CALIFORNIA ISO

California Independent

February 27, 2004

Magalie Roman Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Compensation for Generation Units Subject to Local Market Power Mitigation in Bid-Based Markets: Docket No. PL04-2

Dear Secretary Salas:

Enclosed please find an electronic filing in the above-captioned proceeding of the Comments of the California Independent System Operator Corporation on the February 4 and 5, 2004 Technical Conference. Thank you for your attention to this filing.

Respectfully submitted,

Anthony J. Ivancovich
Counsel for the California Independent
System Operator Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Compensation for Generating Units Subject to Local Market Power Mitigation In Bid-Based Markets | **Docket No. PL04-02-___**

COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON THE FEBRUARY 4 AND 5, 2004 TECHNICAL CONFERENCE

The California Independent System Operator Corporation ("ISO") thanks the Commission for the opportunity to submit comments on the February 4 and 5, 2004 Technical Conference in the above-captioned docket.

Like other independent system operators, the ISO took over the operation of power delivery systems built by vertically integrated utilities to an overall least-cost standard. These systems required that some generating units be operated under certain conditions to comply with reliability criteria. Before restructuring, these units were operated by utilities that had an incentive to maintain and operate these units because they represented the least-cost way of dealing with ensuring reliable service. During restructuring, many of these units were sold to entities whose primary motivation was to maximize the return on their investment. They could do so either by scrapping such older units or by trying to leverage the fact that these units were required to operate to ensure reliability. It has become clear that the separation of the transmission and generation businesses under restructuring raises challenging issues in regards to local market power, revenue adequacy for generating units, and sufficient and efficient investment in electric infrastructure. On these issues, the CAISO offers the following comments:

1. A robust market design requires strong local market power mitigation (LMPM) measures that apply across the entire market. When California restructured its private electric power industry, it chose to deal with the issue of local market power by developing facility-specific Reliability Must-Run (RMR) contracts. Determining which units should be subject to RMR contracts, however, has proven to be a highly contentious issue. The power delivery network is a dynamic system whose configuration can change moment by moment due to necessary maintenance and unforeseen outages. Every generating unit is, under some not-too-implausible set of outage conditions, needed to ensure reliability and therefore able to exercise local market power. To avoid awarding RMR Contracts to every unit in the ISO Control Area, the ISO's Board of Governors adopted criteria specifying a relatively narrow set of conditions (based on the most severe overlapping outages of a generating unit and a transmission line) under which a unit would be eligible for an RMR Contract. As a result, today approximately 10,000 MW of capacity out of a total of 54,000 MW in the ISO Control Area[1] is subject to an RMR Contract. Given that the system the ISO must operate is vulnerable to and often has more outages than the system modeled to evaluate RMR

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[1] Of that total, approximately 41,000 MW is from "participating" resources (resources which have signed a Participating Generator Agreement with the ISO), 10,000 MW from non-participating resources, and 3,000 MW from resources owned or operated by municipal utilities.

eligibility, however, the ISO often requires certain generating units to operate to maintain local reliability – *i.e.*, units that have local market power - that have not been awarded an RMR Contract. Because the opportunity to exercise local market power practically resides with every generating unit, depending on the conditions, local market power mitigation must be applied across the entire market, not just through individual contracts.

2. Units needed to operate to maintain local reliability must have adequate revenue opportunities to recover going forward fixed costs, at least on an average annual basis[2]. While units must not be permitted to exercise local market power, a unit needed for reliability must recover its fixed costs. The reliability consequences of allowing or even forcing such a unit to retire are too great. The ISO believes that fixed cost recovery should be handled outside of hour-to-hour market energy transactions through longer-term bilateral contracts. Attempting to provide fixed cost recovery administratively through hourly market transactions can create perverse market incentives. As an example, the ISO initially implemented an RMR Contract (Type "A") that paid a portion of fixed costs on a per-MWh basis when the unit did not operate through the market but was called under the RMR Contract. As a result, RMR Owners rationally withheld their units from the market or inflated their bids if the profits they could make in the

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[2] Unit owners do not necessarily have to recover the going-forward fixed costs of such units every year but, at a minimum, should have sufficient revenue opportunities to be able to do so on average over several years.

market were less than the per-MWh fixed cost adder in the RMR Contract. Ironically, the "pay-as-you-go" design of the RMR "A" Contract – which was intended to prevent suppliers from exercising market power by withholding supply - created a perverse incentive to withhold units from the market. Paying a unit's fixed costs to ensure it is available to meet reliability needs must also encourage that unit to participate in the energy markets on a short-run marginal cost basis, not encourage it to bypass or withhold from the markets.

3. Where there is a deficiency of supply in a local pocket, it is reasonable to allow prices in that pocket to rise to reflect that scarcity and to encourage investment in that area. But scarcity prices are not a panacea. First, it is imperative that scarcity prices must reflect true scarcity, not ownership concentration. At the most basic level, scarcity exists where 100 MW of load exists in a local area with 50 MW of import transmission and less than 50 MW of generation. Ownership scarcity exists in that same situation where there is 500 MW of generation and all but 49 MW of that generation is controlled by one entity. Moreover, because a power system must maintain a level of reserves, scarcity pricing arguably should apply when operating reserves, including locally-required operating reserves, drop below a certain level (*i.e.*, during times of reserve scarcity as opposed to energy scarcity). However, there are often both tangible and political external realities and barriers to entry that prevent, or severely compromise, the investment needed to relieve the problem.

Environmental, land use or other restrictions restrict the ability to build generation or transmission where power system operating realities would indicate that infrastructure is most needed. Applying scarcity prices in such situations, where legitimate and insurmountable barriers to entry exist, does nothing except create a wealth transfer. Finally, scarcity prices may lead to a self-correcting problem if those prices drive the demand away. Such a solution may be theoretically correct but socially or politically intolerable.

4. The competitive right price in a market without scarcity is the marginal cost of the last resource dispatched to meet the demand requirement. In theory, a scarcity price should reflect demand's marginal value of consumption. In practice, demand is generally inelastic, which requires setting scarcity prices at administratively determined levels, typically at the prevailing energy bid cap.
5. Allowing the spot market to reflect the scarcity price does not guarantee investment. The production and delivery of electric energy requires costly infrastructure that cannot spring forth overnight, particularly in densely populated areas where there is apt to be strong social and environmental opposition to new infrastructure. New power system infrastructure in highly populated areas (*i.e.*, load pockets) requires long planning, permitting and construction lead times and an extensive public process. Additionally, to encourage stable investment, the time frame of the price

signal must correspond to the time frame of the asset. This truth argues in favor of long-term contracts, not volatile spot market prices.

6. The state of electricity markets is such that infrastructure development must be guided by a planning process and not simply rely on spot market signals and responses. While some may assert that building new generation and transmission through a planning process can never have perfect foresight and is therefore prone to inefficiency, the spot market is not yet ready to serve this role on its own. Competitive spot markets may be the best way to allocate scarce supply to demand in situations in which not serving demand is an acceptable outcome. Public policy has not yet moved to the state where cutting off service to those unable or unwilling to bear the spot market price is a viable alternative, nor, as evidenced by this proceeding, have electricity markets proven to be suitably competitive so that the market price is always arrived at or allocated fairly. Discarding the planning process and relying on spot markets to drive investment is like abandoning all health care save emergency rooms. Any system in which progress is precipitated only by crisis is a system in chaos. Markets provide the impetus to spur innovation and benefit all consumers, but California's experience demands that the transition to markets must be careful, not headlong. Market forces should be focused on the long-term, not on the moment.
7. Because local reliability problems stem primarily from the presence of more demand that can be accommodated by the available delivery

capability, the costs of – or price signals for, when the time and method are right - of local reliability problems should be allocated to the local load serving entity. The load serving entity should be responsible for providing that sufficient infrastructure – either generation or transmission capacity – is available and committed to serve its load. The ISO acknowledges the validity of this proposition in proposing to move to Locational Marginal Pricing, in which the costs of operating to accommodate local constraints are reflected in locational prices that are paid by load. While local reliability costs (*i.e.*, the costs of RMR Contracts) are currently assigned to transmission owners, not load serving entities, the ISO ultimately believes that allocating prices to load serving entities via locational prices is the proper approach.

8. Mandating that local load-serving entities maintain adequate local reserves is an approach that can work, provided that steps are taken to ensure that local market power is not simply transferred from the real-time market to the forward contracting market. Such reserves should be procured through long-term bilateral contracts. Moving fixed cost recovery out of real-time participation to long-term contracts re-creates the favorable paradigm that existed prior to restructuring: fixed costs are recovered through stable rates, while the spot market does business purely on the margin.

The ISO again thanks the Commission for convening the technical conference to discuss these important issues and for the opportunity to submit comments.

Respectfully submitted,

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Dated: February 27, 2004

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Folsom, CA, on this 27th day of February, 2004.

For

Anthony J. Ivancovich