UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

AES Redondo Beach, LLC	)))	Docket No. ER98-2843-009

COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON REPORT ON REDESIGN OF CALIFORNIA REAL-TIME ENERGY AND ANCILLARY SERVICES MARKETS

Pursuant to the Commission's October 29, 1999, Notice of Filing and November 8, 1999, Notice of Extension of Time in the above-captioned docket, the California Independent System Operator Corporation (ISO) respectfully submits these comments on the "Report on Redesign of California Real-Time Energy and Ancillary Services Markets," prepared by Dr. Frank Wolak, Chairman of the Market Surveillance Committee of the ISO (MSC), and filed in the above-captioned docket on October 19, 1999.[1] In these Comments, the ISO summarizes and responds briefly to specific issues raised in the Report.

I. Introduction

As discussed below, the ISO concurs with many of the findings and recommendations set forth in the October 19 Report. In these Comments, the

[1] The other two members of the MSC, Robert Nordhaus and Carl Shapiro, have informed the ISO that they concur in general with the Report's findings and conclusions with respect to the ISO's Ancillary Services and real-time Energy markets, and specifically concur with the Report's recommendations concerning maintenance of the ISO's purchase price cap authority and reform of RMR dispatch. These positions are reflected in a letter dated October 19, 1999 from Robert Nordhaus and Carl Shapiro to Jan Smutny-Jones, Chair of the ISO Governing Board, which was filed with the Commission in conjunction with the Report. For ease of reference, the Report prepared by Dr. Wolak is referred to hereafter as the "October 19 Report" or the "Report."

ISO comments on several recommendations and clarifies certain statements contained in the Report. These Comments address the Report's recommendations with respect to the ISO's purchase price cap policy in light of recent actions of the ISO Governing Board and Commission orders which extend the ISO's authority to maintain such caps as needed. The ISO also discusses aspects of the Report concerning the Firm Transmission Right markets.[2] The ISO also addresses a number of specific recommendations in the Report for implementing reforms related to Reliability Must-Run generation. In addition, the ISO offers comments on the options to mitigate market power concerns associated with the divestiture of Pacific Gas and Electric Company's hydroelectric portfolio. Lastly, the ISO addresses a number of topics discussed in the Report relating to the reliable management of the ISO Controlled Grid, including the ISO's Intra-Zonal Congestion Management protocols, its new generation interconnection policy, and the creation of new Congestion Management Zone.

II. Summary of the Report

The October 19 Report reviews the performance of the California ISO's real-time Energy and Ancillary Services markets over the past 18 months (since start-up), with particular emphasis on the relative performance of these markets during the summer of 1999 versus the summer of 1998. The Report also contains a number of specific findings and recommendations for improving the

[2] Capitalized terms not otherwise defined herein are used in the sense given in the Master Definitions Supplement, Appendix A to the ISO Tariff.

overall efficiency of California's wholesale energy markets. The Report's main findings and recommendations are as follows:

- **<u>Market Performance:</u>** The Report concludes that performance of the ISO's Ancillary Services markets during the summer of 1999 appears to be significantly improved relative to the summer of 1998, based on a comparison of sample months. However, this improvement is primarily attributed to lower average hourly total system loads during the summer of 1999 relative to the summer of 1998. The Report states that significant market power remains in California's wholesale Energy market during periods of high total system loads, although the total amount of market power exercised during July 1999 appears to be significantly less than that exercised during that same month in 1998. The Report also suggests that opportunities for the exercise of market power in the ISO's Ancillary Services markets are greater when these markets are cleared on a Zonal versus statewide basis.

- **<u>Price Caps</u>:** The Committee supports the ISO's request for a one-year extension of its authority to maintain maximum purchase prices, and its increase of maximum purchase prices from $250 to $750 effective October 1, 1999. The MSC advises that the caps be left at this level for a full 12 months unless the ISO exercises its "safety net" authority to lower the caps. By the end of the summer of 2000, the MSC believes that the ISO should have enough information on the performance of the ISO's markets under the new Ancillary Services market design and new Reliability Must-Run (RMR) Contracts (and the related pre-dispatch and Day-Ahead scheduling reforms) to evaluate whether removal or raising of this price cap is warranted. Even if the maximum purchase price limits are removed after summer of 2000, the Report recommends that the ISO retain its "safety net" authority thereafter. The Report also indicates that market distortions created by the Competition Transition Charge (CTC) mechanism provide a strong argument in favor of the continued imposition of damage control price caps on all ISO Energy and Ancillary Services markets until the CTC recovery period ends or some of its major market distortions are corrected.

- **<u>Reliability Must-Run Generation</u>:** The Report recommends reforms to implement pre-dispatch of RMR Energy and mandatory Day-Ahead scheduling of RMR capacity to enhance market efficiency, consistent with the market design principles of the California market. Dr. Wolak and the other members of the MSC believe these reforms are necessary for a workably competitive wholesale electricity market.

- **<u>Firm Transmission Rights</u>:** The Report recommends that the ISO monitor the Firm Transmission Right (FTR) markets and establish position limits on the quantity of FTR capacity controlled by any single Market Participant during the initial stages of the operation of this market. Specifically, the MSC favors the imposition of "position limits" at 40% of the available FTRs on any given interface. Market Participants should be required to report all secondary trades of FTRs so that regulators and the ISO can track the ownership of these rights.

- **Price-Responsive Demand:** The Report includes a number of recommendations concerning price-responsive demand. According to the Report, the current retail CTC mechanism creates several impediments to involving price-responsive demand in the Day-Ahead, Hour-Ahead and real-time Energy markets, thereby significantly decreasing the competitiveness of the California electricity market. When the rate freeze ends for a Utility Distribution Company (UDC), the Report advises against implementing a default provider retail rate which passes through hourly wholesale electricity purchase costs. The MSC encourages FERC and the California Public Utilities Commission (CPUC) to coordinate policies to foster price-responsive hourly demand in a cost-effective manner, because the California retail and wholesale markets are highly inter-related. The MSC also states that all prohibitions on forward contracting by UDCs outside of the California Power Exchange (PX) for Energy and Ancillary Services should be eliminated. After the rate freeze period, UDCs and energy services providers (ESPs) should be allowed to offer, in addition to a default provider rate, any bundle of services and prices in order to create full diversity of retail valued-added services.

- **Intra-Zonal Congestion Management:** In the October 19 Report, Dr. Wolak recommends that the ISO revise its Intra-Zonal Congestion Management protocols to create strong incentives for Market Participants to eliminate rather than cause Intra-Zonal Congestion. The Report also states that the ISO should delay implementing any proposal for managing Intra-Zonal Congestion in the forward market until it is convinced that the incentives to cause Intra-Zonal Congestion in the real-time market have been significantly reduced. The Report encourages the ISO to consider two alternative procedures for mitigating Intra-Zonal Congestion: (1) contract in advance for generation units to provide Intra-Zonal Congestion relief services on an annual basis at variable cost for an up-front annual payment similar to the current RMR Contracts. Under this approach, RMR payments for relieving Intra-Zonal Congestion should be charged to the transmission owner(s). (2) treat decremental adjustments supplied for Congestion mitigation as if they were deviations from the generator's Hour-Ahead schedule. All decremental measures taken to relieve Intra-Zonal Congestion should be settled at the hourly ex post real-time price. During any period when the unconstrained Zonal incremental Energy market fails to clear (bids must be skipped over to relieve Intra-Zonal Congestion), incremental Energy would be provided by RMR unit owners at their variable cost, similar to the previous proposal. However, if this RMR unit's variable cost is above the current Zonal price, then this variable cost would set the Zonal Market-Clearing Price.

- **New Generation Interconnection Policy:** The October 19 Report advises that any viable new generation connection policy must contain a policy for managing Intra-Zonal Congestion. Any analysis of the economic efficiency properties of any new generation connection policy will crucially depend on the Intra-Zonal Congestion Management policy in force. The Report suggests that neither the Advance Congestion Cost Mitigation (ACCM) proposal nor the No Grandfathering of Transmission Rights (NGTR) proposal considered by the ISO for its new generation interconnection policy provides the proper economic incentives for when and where to construct new transmission and generation facilities to alleviate Intra-Zonal Congestion. The Report states that this is due in large part to the current ISO protocols for relieving Intra-Zonal Congestion, and that without changes to the current Intra-Zonal Congestion Management protocols, any new generation connection policy is not likely to lead to the geographic distribution of new generation entry and transmission upgrades that will enhance the efficiency of the California electricity market. The Report suggests that it would be prudent to incorporate into any proposed new generation connection policy a revised set of Intra-Zonal Congestion Management protocols. Without a clear statement of these new Congestion Management protocols, Dr. Wolak believes it will be extremely difficult to assess the efficiency properties of any new generation connection policy.

- **New Zone Creation:** Because of the increased opportunities to exercise market power in small Congestion Zones, the October 19 Report cautions against the creation of any Congestion Zones, including the current proposed Congestion Zone south of Path 26, as a way to reduce Intra-Zonal Congestion costs. Unless creating a Congestion Zone substantially improves system reliability, the Report recommends that this process be delayed until there is sufficient experience with the revised Intra-Zonal Congestion Management protocols.

- **Long-Term Grid Planning:** The Report states that the current California market design provides limited incentives for grid upgrades and expansions. In addition, Dr. Wolak notes that the process by which transmission capacity expansion and siting decisions will occur is still the subject of some debate. This is another area identified by the Report where greater communication and coordination between the CPUC and the FERC could enhance the efficiency of the California market over the long-term. The MSC recommends that the CPUC and FERC work in a coordinated effort to remove any regulatory barriers that prevent existing transmission capacity (ETC) owners in California from joining the ISO.

The MSC also recommends that the ISO proceed with a proposal to provide non-firm transmission service, using unscheduled ETC capacity, because it will allow ETC holders greater flexibility to participate in the ISO's markets and give the ISO Market Participants greater access to unused transmission capacity.

- **PG&E Hydro divestiture:** The Report recommends that hydroelectric assets owned by Pacific Gas and Electric Company (PG&E) be divested on a watershed-by-watershed basis to a buyer unaffiliated with PG&E or other major generation owners in Northern California.

III. ISO's Response to Specific Issues Raised in the October 19 Report

The ISO commends Dr. Wolak for his very thorough and substantive analysis of California's wholesale Energy markets, the improvements made to those markets since start-up, and the many challenging issues facing the ISO and stakeholders in our continued efforts to improve the efficiency and competitiveness of these markets. While the ISO concurs with many of Dr. Wolak's findings, the ISO would like to clarify and comment on several recommendations and/or statements contained in the Report. Specifically, the ISO's comments pertain to the areas of the ISO's purchase price cap policy, RMR reforms, FTRs, PG&E hydro divestiture, and several topics relating to managing the ISO grid (*i.e.*, Intra-Zonal Congestion Management protocols, new generation interconnection policy, and new Zone creation).

A. ISO Purchase Price Cap Policy

The October 19 Report strongly recommends that the ISO maintain authority to impose maximum purchase price limits in the Ancillary Services and real-time Imbalance Energy market and recommends that these limits remain at $750 for a full year beginning October 1, 1999 unless the ISO exercises its "safety net" authority to lower them. Although this recommendation is largely consistent with the ISO Governing Board's August 6, 1999, price cap resolution, the Board's resolution contains a provision that directs the ISO to reduce the purchase price cap to $500 effective June 1, 2000 if the ISO Governing Board determines, based on a report from ISO management, that: (1) the markets are not workably competitive; (2) there are not practicable demand side management options in place; or (3) the IOU Utility Distribution Companies have sought and not obtained practicable options to self-provide Ancillary Services and applicable hedging products in the Power Exchange consistent with California Public Utilities Commission Preferred Policy Decisions. In adopting this price cap resolution, the ISO Governing Board recognized that the effectiveness of the ISO's Ancillary Service market redesign efforts has not been confirmed through practical experience and that RMR Contracts have not yet been reformed in a manner consistent with the ISO MSC and the PX Market Monitoring Committee recommendations, which, as discussed below, are confirmed in the October 19 Report. The Board also recognized that demand remains inelastic, in part due to the limited ability of entities serving demand to protect customers against high prices through demand management and hedging products. The ISO believes it would be imprudent to maintain the $750 cap through the summer of 2000 if these three elements, which the ISO believes are essential for a workably competitive market, are not in place. The ISO also notes that, since the October Report was filed, the Commission has accepted an amendment to the ISO Tariff that will give the ISO the authority to maintain and adjust its purchase price cap for Ancillary Services and Imbalance Energy, consistent with the Governing Board's resolution.[3]

B. FTRs

The Report recommends that the ISO monitor the FTR markets for the exercise of market power and establish limits on the quantity of FTR capacity that may be controlled by any single Market Participants (including that entity's affiliates) during the initial stages of the operation of the FTR markets. More specifically, the Report recommends that any one entity (including that entity's affiliates) not be allowed to hold or control more than 40% of the FTRs available on any given interface. The ISO has already filed as part of Amendment No. 22 to the ISO Tariff a requirement that entities who acquire FTRs through either the primary FTR auction or the FTR secondary market to notify the ISO of its affiliates that are either FTR Holders or ISO Market Participants. As explained in the Amendment No. 22 transmittal letter, the ISO believes that it is not necessary at this time to impose any position limits on the ownership or control of FTRs. The ISO has, however, developed a special monitoring system to track FTR ownership, the exercise of strategic scheduling (overscheduling), and the impact of FTRs on the Adjustment Bid market and the prices in the Congestion Management, Ancillary Services, and real-time markets. If inappropriate scheduling behavior, market inefficiencies, or market power attributable to FTR concentration are observed, the ISO's Department of Market Analysis (DMA) will recommend any appropriate corrective actions, including amending the ISO Tariff

3 *California Independent System Operator Corp.*, 89 FERC ¶ 61,169 (November 12, 1999).

to impose position limits or to implement other mitigation measures, such as sanctions.

The Report also states that, by auctioning the FTRs, the ISO is selling a product at an expected loss to California consumers (*i.e.*, the price paid for FTRs will be less than the Congestion revenues the FTR buyer expects to receive). This might be true if the buyers were bidding only for the financial entitlement of FTRs. FTRs, however, also provide FTR Holders with a Day-Ahead scheduling priority, an attribute that stakeholders have informed the ISO that they consider to be a key attribute of the product. It is therefore likely that a buyer of FTRs will pay a premium above the expected Congestion rents, resulting in a net gain for consumers rather than a net loss.

The Report recommends that Market Participants be required to report all secondary trades of FTRs so that regulators and the ISO can track the ownership of these rights. The ISO has already amended its tariff to require such disclosure. The ISO will post on the ISO Home Page the ownership of FTRs as a result of the primary auction as well as secondary market transactions. In addition, the ISO will publish certain additional information, including the prices at which FTRs are sold in the primary auction and secondary market, consistent with the Commission's recent order on FTRs.[4]

C. Reliability Must-Run Generation

The ISO agrees with the conclusions of the October 19 Report regarding the beneficial impacts of modifying the current RMR dispatch and scheduling

4 *California Independent System Operator Corp.*, 89 FERC ¶ 61,153 (November 10, 1999).

protocols. As noted in the Report, pre-dispatch of RMR and scheduling of RMR in the Day-Ahead market: (1) is consistent with the market design principles of the California Energy market, where all Day-Ahead and Hour-Ahead Energy requirements are submitted to the ISO in balanced schedules; (2) would enhance market efficiency by providing better certainty about when RMR Energy requirements are scheduled; (3) would reduce the volatility of wholesale Energy prices and overall wholesale Energy costs, and (4) would improve system reliability by reducing the need to adjust schedules in real time.

The ISO agrees with the Report's principal conclusions regarding RMR scheduling and dispatch. However, the ISO disagrees with several recommendations in the Report regarding the specific mechanisms for scheduling and payment of RMR Energy.

- *Daily versus hourly selection between contract and market paths*. If RMR Energy is dispatched prior to the close of forward Energy markets, RMR Owners would have the option either to accept payment under their RMR Contracts (the "contract path") or committing to supply the dispatched Energy under a market transaction (the "market path"). The Report recommends that RMR Owners be given the opportunity to make this election on an hourly basis. The ISO believes that it is more equitable and consistent with actual market conditions for owners to be required to select between the market and contract paths on a daily rather than hourly basis (*i.e.*, all RMR requirements from an RMR Owner for each operating day must be provided under the same path). If selection is allowed on an hourly basis, RMR Owners benefit from market revenues during individual hours when prices are high, while having the responsible transmission company pay the difference between market prices and the unit's variable costs during hours when prices are low. This would insulate RMR Owners from market price fluctuations during the day to an unnecessary and inappropriate extent.

- *Payment options under market path.* The Report recommends that RMR Owners electing the market path be required to include their unit-level RMR Energy requirements in a balanced Day-Ahead schedule, but be allowed to elect to be paid the Zonal PX Day-Ahead price, Zonal PX Hour-Ahead price, or the Zonal ISO imbalance price. The first part of this recommendation is correct and, indeed is critical: RMR Energy dispatched by the ISO must be included in a balanced schedule in a forward market. The ISO believes, however, that the second portion of this approach may create market distortions and gaming opportunities, since RMR Owners could elect to receive the Market Clearing Price (MCP) from a market other than the market in which this Energy is actually scheduled. Under the ISO's preferred approach, RMR Owners selecting the market path would simply keep any revenues they receive from the market transaction in which it fulfills the obligation to make the dispatched Energy available.

The Report also states that an RMR Owner could "balance the total unit-specific RMR generation that it must provide in its day head schedule with fictitious load," so that the owner would, in effect, be "simply selling this generation in the real time market."

First, under the pre-dispatch provisions that the ISO has circulated to RMR Owners, an RMR Owner cannot fulfill the requirements of the contract path by scheduling RMR generation with fictitious load. The ISO recognizes that California's market design allows any entity with scheduling ability to take a financial position in the real time market by simply over scheduling demand in the forward Day-Ahead or Hour-Ahead markets, and receiving payment for this positive imbalance at the real time price. However, under the approach to pre-dispatch of RMR preferred by the ISO, owners selecting the contract path receive the variable cost payment and would be required to schedule this energy against demand in the Day-Ahead market through a zero-priced bid in the PX. If the RMR Owner schedules "fictitious" load when it is providing RMR under the contract path, the owner must actually buy this energy at the PX price and then receive a credit for the resulting positive imbalance at the real time price. This represents a separate transaction that an owner can make *with* or *without* pre-dispatch and netting out of RMR, based on the owner's expectation of prices in the PX and real time markets. For any given set of price expectations in these two markets, any position that the owner takes in the real time market would be the same, with or without pre-dispatch of RMR. Thus, the incremental effect of pre-dispatch is to ensure that all energy provided under the contract path is scheduled in the Day-Ahead market through a zero-priced bid in the PX, rather than being dispatched after the Day-Ahead market and showing up unscheduled against demand in real time.

Second, the market path in the ISO's preferred RMR procedures contemplates generators scheduling RMR Energy against real load in the Day-Ahead and Hour-Ahead schedules. The ISO acknowledges that generators will nonetheless continue to be able to, in effect, sell Energy in the real time price by scheduling "fictitious" load in the forward markets and then generating in real-time, as noted in the Report. Under the market path of dispatch protocols preferred by the ISO, this ability to effectively sell Energy in real time by over-scheduling of demand is neither increased nor decreased. In addition, it should be noted that the ISO has implemented a variety of market redesign measures aimed at reducing incentives that have existed for units to generate uninstructed in real time. Some of these measures, such as billing of Replacement Reserve costs based on deviations from schedules, were implemented in August 1999, while others, such as settlement based on 10-minute prices, are expected to be proposed and implemented in the coming year.

D. PG&E Hydro Divestiture

The October 19 Report concurs in the DMA's assessment that the terms of the divestiture of PG&E hydro resources "are critical to the functioning of California's ancillary services markets, and that effective market power mitigation measures must be put into place." However, the Report states that the Committee believes that "behavioral" mitigation measures (such as bidding rules and minimum capacity availability requirements) are complex and difficult to enforce." Therefore, the Committee recommends that PG&E's hydro assets be divested on a watershed-by-watershed basis to a buyer unaffiliated with PG&E or other major generation owners in Northern California.

The ISO believes that the overall management of California's water resources rests with entities other than the ISO but that certain issues raised in the October 19 Report must be addressed. The ISO has, to date, not taken a position on the merits of divesting PG&E's entire hydro portfolio to an unregulated subsidiary vs. divesting the portfolio on a watershed-by-watershed basis. Resolution of this question involves much larger political and social issues, and does not rest solely on the issue of market power mitigation. The ISO's role, however, is and has been limited to proposing effective market mitigation measures for a number of possible divestiture scenarios.

The ISO believes that three main options exist that can effectively mitigate the market power concerns associated with divestiture of PG&E's hydro portfolio to an unregulated subsidiary of PG&E or to other entities:

- Structural. Divest the hydro resources to a large number of suppliers. In addition, entities that purchase the hydro assets must not own significant amounts of other resources that participate in the California electricity markets. This feature is necessary so that transfer of ownership does not create or exacerbate market power.

- Contractual. Require contractual agreements, such as Contracts for Differences (CFDs), under which an owner, in effect, sells output at a fixed price under a long term contract. This type of market power mitigation is widely used in England and Australia, and is being proposed in New York.

However, CFDs are currently not a viable market power mitigation tool in California due to CPUC restrictions on investor-owned utility loads entering into bilateral contracts.

- Behavioral Rules. Establish restrictions on bid quantities and prices, similar to the principles developed by the ISO and PG&E. Bidding restrictions can be effective at eliminating bidding at excessive prices and withholding capacity. Bidding restrictions would allow the ISO to set minimum Ancillary Service bid quantities which must be bid at a price no greater than a maximum bid price (initially set at $20), thereby ensuring bid sufficiency. All other available capacity must also be bid in at prices not to exceed an Energy index price (based on the average price of Energy during peak hours each month in relevant Energy futures markets). This approach would allow the ISO to ensure that, when prices are high due to underlying market conditions, PG&E is a "price taker", with prices being set by other suppliers.

The appropriateness and details of using any of these approaches (individually or in combination) must be addressed on a case by case basis, based on factors which include, but are not limited to:

- The total amount and type of generation resources owned by the entity.
- The amount and type of other generation resources available relative to demand in the California Energy and Ancillary Service markets.

- The feasibility of other sources of market power mitigation which are currently unfeasible or very limited in California's Energy market, such as Contracts for Differences, long term contracts between buyers and sellers, and greater elasticity of demand in the Energy and Ancillary Service marketplace.

A key point that the ISO has made throughout the discussion of this issue is that each divestiture option can only be examined once the specific details are known or developed. The market power mitigation plan previously developed by the ISO was specifically designed to establish market power mitigation measures that would be sufficient to address a situation in which PG&E's entire hydro portfolio was sold to an unregulated subsidiary. Other scenarios, including divestiture on a watershed-by-watershed basis, would need to be accompanied by additional analysis of market power issues given the specific divestiture options under consideration.

E. Intra-Zonal Congestion Management

The October 19 Report correctly identifies the inherent problem of relying on Adjustment Bids to manage Intra-Zonal Congestion in situations where there is not a competitive Adjustment Bid market. The Report also correctly notes that, in a non-competitive market, a generator with locational market power can create Intra-Zonal Congestion in its forward schedule, and then submit a high decremental Adjustment Bid, cognizant of the fact that the ISO would have to call on this bid to relive the Congestion.[5] As the Report explains, the solution to the problem is to perform Intra-Zonal Congestion Management in a manner that eliminates the potential for the generator to benefit financially from this behavior.

The ISO is now in the process of examining and clarifying its protocols for addressing a non-competitive Intra-Zonal Congestion Management market.[6] The revised protocols follow the overall framework recommended in the Report, but differs on a few of the implementation details. The approach developed by the ISO is based on the principle of paying and charging units called for Intra-Zonal Congestion Management based on either pre-established costs or market prices, rather than relying on Adjustment Bids in all circumstances, including when a competitive market for Congestion relief does not exist. Specifically, the ISO's procedure for addressing a non-competitive Intra-Zonal Congestion Management market is to: (1) call on RMR units to relieve Intra-Zonal Congestion when such units are available and would be effective; or (2) in the absence of effective RMR units, call on any generating unit that can effectively relieve the Congestion and that has a Participating Generator Agreement (PGA) with the ISO, and pay such unit either: (1) an incremental rate which contains both cost-based components (*i.e.*, start-up and gas imbalance) and components indexed to prevailing market prices; or (2) charge them the *ex post* price if such unit is called

[5] One way bidders could exercise such market power is to play the so-called "DEC game," a tactic whereby a bidder schedules a unit (or a portfolio of units) so as to create Intra-Zonal Congestion, and then submits a highly negative DEC bid knowing that the ISO will have to call on that bid to relieve the Intra-Zonal Congestion so created.

[6] The ISO recently provided the Commission with an explanation of its procedures for real-time non-competitive Intra-Zonal Congestion Management in its request for rehearing of the Commission's order on Amendment No. 19 to the ISO Tariff, filed in Docket No. ER99-3339 on October 15, 1999.

to decrement (DEC) its output.[7] With this modification the ISO believes that the concerns expressed in the Report should be fully addressed.

The most significant detail on which the ISO's procedure differs from the Report's recommendation has to do with the price paid to an RMR unit called to increment (INC) to resolve Intra-Zonal Congestion. The Report recommends that, if an RMR unit's variable cost is above the Zonal MCP, then its variable cost should set the Zonal MCP. It appears that Dr. Wolak's intent is to use the resulting higher *ex post* price as a disincentive for generators to play the "DEC game" by charging the variable cost-based price to units called to DEC to resolve the Intra-Zonal Congestion. The ISO believes that this proposal creates a more severe disincentive than that proposed by the ISO, and that it may have the unintended consequence of increasing the cost of Intra-Zonal Congestion Management, particularly in instances where the DEC side of the constraint is competitive while the INC side is not.[8] The proposal outlined in the Report could

[7] The ISO recently filed Amendment No. 23 to the ISO Tariff, which would provide generating units with an alternative payment option when those units are called upon to manage intra-zonal congestion where there are insufficient effective economic bids available to manage congestion in real-time or when a competitive market for such bids is not present. This proposal also clarifies the circumstances in which the ISO will use its authority to dispatch resources when such conditions are present.

[8] For example, assume that there is no Inter-Zonal Congestion, the system-wide market clearing price is $25/MWh, and the Imbalance Energy volume it applies to is 3,000 MWh. The Supplemental Energy market is competitive. However, in this example, there is Intra-Zonal Congestion involving a small sub-zone, where 50 MWh incremental Energy is needed to resolve it, and the only available unit in that small sub-zone is an RMR unit with a variable cost of $40/MWh. Under the current operating practices, the RMR unit would be called and paid at its variable cost, *i.e.*, it would receive $40*50 = $2,000. An equal amount of 50 MWh should be decremented on the system-wide side of the interface. Since a competitive market does exist there, the marginal unit (at $25/MWh) would be decremented and charged $25*50 = $1250. The net Intra-Zonal Congestion Management cost would be $750. Following the procedure suggested in the Report, the $40/MWh price would apply to all incremental generation, resulting in an additional cost of ($40-$25)*(3000-50) = $44,250. Moreover, there may be a large number of system-wide bids between $25 and $40, submitted in a competitive system-wide Imbalance Energy market, that are not selected, but see a real-time Imbalance Energy MCP of $40**.**

also provide an incentive for generation portfolio owners with high-cost RMR units to bid aggressively into the real-time market so that their dispatch would create real-time Intra-Zonal Congestion, force a real-time call on the high-cost RMR unit, and thereby set the price for their entire portfolio. The ISO therefore believes that it's approach is preferable. Although the ISO recognized that its approach does not provide as strong a signal to discourage the DEC game as the Report's approach, the ISO believes that it establishes a sufficient disincentive.

F. New Generation Interconnection Policy

The Report's recommendation regarding New Generation Interconnection Policy (NGIP) focuses on the need for effective Intra-Zonal Congestion Management and does not necessarily find fault with the specific details of the ISO's NGIP. As previously explained, the ISO's non-competitive Intra-Zonal Congestion Management procedure should effectively ensure that a generator with locational market power will not be able to exercise that market power to create and financially benefit from Intra-Zonal Congestion. As applied in the context of the ISO's NGIP, the ISO's non-competitive Intra-Zonal Congestion Management procedure will ensure that an incumbent generator cannot create a barrier to entry by forcing a potential new entrant to pay exorbitant costs to mitigate any incremental Intra-Zonal Congestion resulting from that entrant's operation when such congestion cannot be addressed through the market. The ISO believes that under the new Intra-Zonal Congestion Management procedure, the NGIP will provide proper locational economic incentives for new generation.

The NGIP establishes a proper incentive to build plants in areas where new generation would have a minimal impact on reliability and congestion. The ISO believes, therefore, that the Report's recommendation in this area should be satisfied.

G. New Zone Creation

The October 19 Report recommends that, because of the increased opportunities to exercise market power in small Congestion Zones, the ISO should not create any Congestion Zones as a way to reduce Intra-Zonal Congestion costs. The Report further recommends that, unless creating a Congestion Zone substantially improves system reliability, the creation of any Congestion Management Zones should be delayed until there is sufficient experience with the revised Intra-Zonal Congestion Management protocols.

The ISO also notes that there are numerous advantages to creating a new Congestion Management Zone which are not addressed in the Report. Converting a transmission path to an Inter-Zonal interface permits forward management of Congestion on that path. Currently, Intra-Zonal Congestion is managed only in real-time, while Inter-Zonal Congestion is managed in the forward markets. Because Inter-Zonal Congestion costs are assigned to the Scheduling Coordinators who use the constrained Inter-Zonal interface, creation of a new Zone also provides for better allocation of Congestion Management costs. This also permits Scheduling Coordinators to place a value on their schedule over a congested interface by submitting Adjustment Bids. Thus, while creation of a new Zone will not necessary lead to a reduction in Congestion

Management costs, as recognized in the October 19 Report, it does provide the marketplace a signal that Congestion is substantial and permit the market to mitigate that Congestion competitively. The creation of a new Zone is therefore appropriate in circumstances where Congestion on an existing transmission path is substantial, as was the case with Path 26.

The ISO has explained the need for, and the ISO Governing Board's approval of, a new Congestion Management Zone south of Path 26 in its filings in Docket No. ER99-4545. The ISO believes that in the case of Path 26, Intra-Zonal Congestion would be prevalent even in the absence of the gaming opportunities under the current procedures for relieving Intra-Zonal Congestion. Furthermore, managing Intra-Zonal Congestion on Path 26 in real-time has proven to be extremely problematic and to some extent, a threat to system reliability. For example, because of the importance of Path 26 to the ISO system, the ISO needs to consider Path 26 Congestion in procuring Ancillary Services in the forward markets, which it cannot do systematically if Path 26 remains an Intra-Zonal pathway. For these reasons, the ISO remains convinced that it is necessary to create a new Zone south of Path 26.

IV. Conclusion

The ISO respectfully requests that the Commission accept these Comments and take them into account in its consideration of the Report on Redesign of California Real-Time Energy and Ancillary Services Markets.

Respectfully submitted,

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Dated: November 16, 1999

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all parties on the official service list compiled by the Secretary in the above-captioned dockets, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, D.C. this 16th day of November, 1999.

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Sean A. Atkins