UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)	Docket No. ER00-997-000

**ANSWER OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
TO MOTIONS TO INTERVENE AND REPLY COMMENTS**

On December 30, 1999, the California Independent System Operator Corporation ("ISO") submitted the "Market Power in the San Diego Basin Addendum to Annual Report on Market Issues and Performance" prepared by the ISO's Department of Market Analysis ("DMA") in the above-captioned docket.[1] Pursuant to Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213, the ISO hereby submits its Answer to Motions to Intervene and Reply Comments to comments submitted in response to the December 30 filing.

I. Introduction

As explained in the ISO's December 30 transmittal letter in this proceeding, the Report was prepared in compliance with the Commission's October 30, 1997 order authorizing the ISO to commence operations, *Pacific Gas and Electric Co., et al.*, 81 FERC ¶ 61,122 (1997) ("October 30 Order"). In the October 30 Order, the Commission accepted the market power mitigation

1 For ease of reference, this document is referred to hereafter as the "December 30 Report" or the "Report."

proposal of San Diego Gas & Electric Company ("SDG&E") as adequate to mitigate market power during a transition period discussed in the order. The Commission also directed the ISO and the California Power Exchange ("PX") to "monitor for market power in the San Diego Basin and to present information in their annual reports that would assist in the evaluation of this issue." October 30 Order at 61,546. In a subsequent letter order the Commission accepted the ISO's first *Annual Report on Market Issues and Performance* (submitted June 4, 1999) and required the ISO, consistent with the October 30 Order, "to submit, by December 31, 1999, a report addressing an evaluation of the market in the San Diego Basin." *California Independent System Operator Corp.*, 88 FERC ¶ 61,284 (1999).

The December 30 Report provides a preliminary analysis of market power in electric generation in the San Diego Basin as an addendum to the ISO's first *Annual Report on Market Issues and Performance*. The Report presents background on regulatory and policy decisions relating to market power, an overview of demand and supply conditions, the methodology used in the Report to assess market power, and the implications of issues and trends identified in the Report. The Report concludes that any major market design changes to address market power in the San Diego Basin, such as modification of Reliability Must-Run ("RMR") Contract requirements or creation of a new Congestion Management Zone, be preceded by more detailed analysis of how market power in the Basin might be affected by any proposed changes.[2] The Report also

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

contains the recommendation that market power considerations be incorporated into the analysis of different options for meeting new Load growth in the San Diego Basin, including new transmission capacity, new generation, repowering of existing Generating Units, and demand-side options.

The ISO does not oppose any of the motions to intervene, but does respond to some of the comments submitted in order to clarify the ISO's position on certain matters and to note that some issues raised in those comments will more properly be addressed in other proceedings.

II. Answer to Interventions

On January 5, 2000, the Commission issued a Notice of Filing concerning the December 30 Report. The Public Utilities Commission of the State of California ("CPUC") filed a notice of intervention, and motions to intervene were filed by several parties.[3] The ISO does not oppose any of the Motions to Intervene. In addition, a number of parties filed comments on the December 30 filing.[4]

III. Reply Comments

Most of the parties commenting on the December 30 Report generally agree with the analysis and the conclusions set forth in the Report. Oversight Board at 2-3; DWR at 4; CPUC at 3. None of the parties commenting on the Report suggest that it does not comply with the Commission orders discussed above.

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[3] Timely motions to intervene were filed by the California Electricity Oversight Board ("Oversight Board"); the City and County of San Francisco; Sempra Energy ("Sempra"); and Williams Energy Marketing & Trading Company ("Williams"). The California Department of Water Resources ("DWR") and Southern California Edison Company ("SCE") filed motions to intervene out of time.

[4] The following parties filed comments on the December 30 Report: DWR; the Oversight Board; Sempra, and Williams.

Nonetheless, the ISO believes it is appropriate to respond to certain of these comments. Some of these comments raise issues which the ISO will properly address in other proceedings, while others contain statements that are more likely to confuse, rather than clarify, the Commission's understanding of the Report's methodology and findings, as well as actual operating practices under California's market design.

As several parties note in their comments, the Commission, in its order on Amendment No. 23 to the ISO Tariff, has recently directed the ISO to undertake a review of its Congestion Management system and specifically its mechanism for managing Intra-Zonal Congestion.[5] Sempra at 3; Oversight Board at 5. The ISO is currently evaluating all the ramifications of the January 7 Order and how best to respond to the FERC directive. The ISO believes that the Amendment No. 23 proceeding, and any review process that will be initiated in response to the January 7 Order, are the proper forums for addressing many of the issues raised by commenters. In fact, Sempra's comments raise a number of issues and offer various suggestions about the ISO's Congestion Management design that Sempra acknowledges will be best addressed as part of that process. *See* Sempra at 3-4, 7-8. For example, Sempra's comments include a suggestion that the ISO create a new "San Diego" Congestion Management Zone. The creation of such a new Congestion Management Zone is clearly a possibility to be considered as part of the review process directed in the January 7 Order. The ISO welcomes the input of Sempra and all other stakeholders as part of that process.

[5] *California Independent System Operator Corp.*, 90 FERC ¶ 61,008 (January 7, 2000) ("January 7 Order").

Sempra's comments also raise questions about the December 30 Report's methodology and its conclusions to which the ISO believes it must respond. Specifically, the ISO seeks to clarify the Report's findings about the occurrence of Congestion in the San Diego Basin, and the role that RMR Contracts have had in mitigating (or avoiding) Congestion that may have occurred in the Basin as a result of the exercise of local market power in the absence of RMR Generation.

Sempra claims that the December 30 Report reaches the conclusion that San Diego does not meet the existing criteria for creation of a new Congestion Management Zone "even though [the ISO] is able to develop little factual information about how much transmission congestion actually arises from serving the San Diego Basin." Sempra at 4. This claim ignores the Report's specific discussion of this issue. The methodology used to assess the degree to which Congestion would have occurred in the Day-Ahead Market given the amount of generation scheduled within the Basin through the market (*i.e.*, in response to Market Clearing Prices in the ISO's Southern Zone ("SP15")) is described on page 19 of the Report.

The methodology is based on three factors for which historical data are available and have been applied: (1) the total amount of generation inside the Basin scheduled in the Day-Ahead Market (*before* any adjustments or incremental generation necessary to meet RMR requirements); (2) total demand in the San Diego Basin; and (3) the amount of transmission capacity into the Basin. Results of this analysis presented on pages 20-21 of the Report show that, over the recent 12 month period used in the analysis, "the difference between total demand and generation scheduled in the Day-Ahead Market within the Basin [*i.e.*, the net demand for transmission into the basin] exceeded the 2,450 MW level [the available transmission capacity] during only 5 hours." This analysis shows that, contrary to Sempra's claim, virtually no Day-Ahead Congestion would have occurred given the amount of generation scheduled by suppliers within the Basin in response to Market Clearing Prices in the ISO's Southern Zone (this analysis is based on a hypothetical world *without* RMR *and* without locational market power). Attachment A to this filing includes a numerical example that further illustrates both the methodology and basic findings referenced above.

Sempra faults the Report for not adequately explaining how the preservation of "reliability" is technically distinguishable from the management of Intra-Zonal Congestion. Sempra at 5. An example of how local reliability may in some cases be differentiated from management of Intra-Zonal Congestion is provided in Attachment A. As explained above, analysis of generation within the Basin that is scheduled in the Day-Ahead Market in response to market prices shows that, in the case of the San Diego Basin, RMR Generation dispatched based on local reliability requirements does not "mask" any Congestion that would otherwise occur into the Basin under competitive market conditions. Rather, RMR Generation merely serves to mitigate (or avoid) congestion that would occur due to the exercise of local market power through withholding or curtailment of generation. Congestion would arise under these circumstances when generation is withheld in the Basin and there is a need to import a significant amount of Energy, thus congesting transmission paths into the Basin.

In the absence of RMR Contracts, significant real-time Intra-Zonal Congestion may indeed have occurred in the Basin due to the exercise of local market power. Given the high concentration of ownership in the Basin, either of the two major owners of generation in the Basin could frequently cause Congestion by simply curtailing the amount of generation they scheduled in the Day-Ahead Market (or curtailing scheduled generation from one of their units)[6]. The generation owner could then force the ISO to call for additional generation out-of-sequence at a very high bid price (*e.g.*, the currently applicable price cap of $750) to resolve the resulting Congestion. Whether such a strategy would be profitable would, of course, depend on the factors such as the amount of generation that would need to be curtailed to create Congestion, the real-time imbalance price in SP15, and the *residual demand* within the basin (*i.e.*, the demand that could not be met by a combination of the imports from SP15 and the other major supplier in the Basin). The Residual Supply Index ("RSI") utilized in the December 30 Report provides an indication of this final factor, or the demand that could not be met by a combination of the imports from SP15 and the other major supplier in the Basin.

[6] If a generation owner curtailed generation from one unit that had been scheduled in the Day-Ahead market, the Generator would pay for the resulting imbalance at the real-time price in SP15, the ISO's Southern Zone, (*e.g.*, $50). However, in the absence of RMR Contracts, the owner could earn a much higher payment for generation from another of the owner's units in the Basin bid at a very higher price (*e.g.*, $750) that would need to be called by the ISO to resolve congestion.

Sempra states that "the creation of new zones [in areas such as San Diego] allows for the possibility of reducing the aggregate cost to consumers of meeting load under the current market power mitigation system, while consumers would fare no worse than under the CAISO's current procedure for managing congestion into the San Diego Basin, even if market power exists in the new zone." Sempra at 6.

In California's current market design, a key difference between *Inter-Zonal* and *Intra-Zonal* Congestion Management is that Inter-Zonal Congestion Management is performed in the Day-Ahead Market (through which the bulk of Energy is traded and scheduled), as well as the Hour-Ahead Market, while Intra-Zonal Congestion Management is performed as part of the real-time imbalance market. As explained in the Report, an examination of the Day-Ahead Market Energy schedules submitted by generators in the Basin (*before* any additional incremental Energy is dispatched in the Basin to meet local reliability criteria) indicates that Congestion into the Basin in the Day-Ahead Market would be very rare and infrequent (*i.e.*, only four hours during the recent 12 month period used in the analysis). Under California's Zonal market design, differences in the final Day-Ahead Market clearing prices of any two adjacent Zones only occur when Congestion occurs and is resolved by utilizing Adjustment Bids. Thus, the analysis of Day-Ahead Market Energy schedules submitted by generators in the Basin presented in the Report indicates that, at least in the continued absence of an ability to exercise local market power in the Basin, the creation of a new Zone in San Diego would not have resulted in a price differential of between this new

Zone and the adjacent Zone (SP15) during the recent 12 month period used in the analysis).

The ISO attributes the fact that local market power has not, to date, been exercised in a way that creates Congestion into the Basin in the Day-Ahead Market to the fact that market power has been effectively mitigated by a combination of two factors: (1) units in the Basin scheduling Energy in the Day-Ahead Market are paid the Market Clearing Price in the ISO Southern Zone, rather than a separate Zonal price that can be affected by the exercise of local market power; and (2) any effort by generators inside the Basin to exercise local market power and thereby get called out-of-sequence in the real-time and paid a very high bid price is mitigated by RMR Contracts. As noted below, the ISO has committed to conduct a study which addresses the impact of RMR Contracts on Intra-Zonal Congestion and on the ISO's criteria for creation of new Zones. The ISO will address the type of concerns raised by Sempra in the context of that study.

Sempra also seems to suggest that, simply because the San Diego Basin includes 1.2 million end-use meters, it should be treated as a separate Congestion Management Zone. Sempra at 4. The ISO believes that criteria based on economic considerations will result in better overall market and system efficiency than a method where Zonal boundaries are established only on the basis of number of customers. The ISO believes that the current criteria for creating Zones (*i.e.*, a significant level of Congestion and workable competition) is appropriate, but, as noted above, will consider alternative methodologies in the context of the discussions in other, more appropriate, forums.

Several parties comment on the ISO's use of simulations instead of historical data for aspects of the Report. Williams suggests that the use of such simulations results in a Report that is subject to "considerable interpretive debate." Williams at 3. Sempra criticizes the ISO for "resorting" to Monte Carlo simulations, rather than actual bid data in performing its analysis of market power. In the structural analysis of market power presented in the Report, Monte Carlo simulations were merely used to represent unplanned unit outages in an unbiased, objective manner. Representing such contingencies through Monte Carlo simulations is a standard and commonly accepted practice in economic analyses. In such analyses, the major source of potential bias or error is the assumed forced outage rate. The ISO notes that, throughout its analysis, the ISO intentionally selected assumptions that underestimate, rather than overestimate, market power. However, because these parties did not raise specific concerns with any of the inputs used in the analysis, the ISO cannot respond to any specific problems. As explained further below, Sempra faults the ISO's basic methodology or approach, but does not identify any specific flaws in the ISO's study nor proffer a viable alternative approach.

Sempra faults the December 30 Report for failing to "develop a historical record of the PX bids submitted by the generators located in the San Diego Basin." Sempra at 4-5. On page 16 of the Report, it is explained that actual bid data were not used in the study for two reasons. First, actual bids for resources in San Diego cannot be determined due to the fact that generation owners bid portfolios of supply resources -- rather than individual units -- into the PX. Since the resource portfolio of each of the two suppliers in the Basin operate include supply resources outside the Basin, PX bid data cannot be linked directly to units in the San Diego Basin. The second, and most important, reason cited is the ISO's expectation that historical bidding would be affected significantly by RMR Contracts. This, combined with the fact that the Basin is not a Zone, has removed any incentive for generators to try to exercise local market power in order to raise either Day-Ahead or real-time market prices. In other words, since the potential to benefit from the exercise of local market power has been mitigated to a large degree by RMR Contracts throughout most of the 12 month period used in the Report's analysis, the ISO expects that bidding data during this period is not reflective of the bidding behavior the ISO would expect in the absence of RMR Contracts. In such a case, the ISO would expect the local market power existing in the Basin to be exercised.

Sempra goes on to recommend that the Commission "consider adopting measures to ensure bidding information is available by location so that the DMA and other monitoring institutions will have an adequate behavioral record to analyze." Sempra at 5. Portfolio bidding in the PX Energy market is a key feature of California's market design that is intended to allow suppliers to bid aggregated resource portfolios in the PX, and to then allocate Energy that "clears" the PX market to individual units in the owner's portfolio in an optimal manner, taking into account unit operating constraints, unit efficiency at different operating levels, and subsequent opportunities in the Ancillary Service and real-time markets. While the

ISO agrees with Sempra that it would be preferable to have available more detailed and accurate information on locational differences in bid prices, portfolio bidding in the PX is a fundamental and important feature of the California market and is a feature which reduces the usefulness of locational bid data.

Williams claims that the ISO's approach of equating "all generation bidding in excess of marginal costs as potentially reflective of market power" perpetuates a "fundamental flaw in the ISO's market power assessments. Williams at 3. Williams specifically suggests that the ISO's bid mark-up and Residual Supply Index analyses have not been subject to academic scrutiny. Williams, however, offers no substantive critique of these analyses. As the ISO has noted elsewhere,[7] it continues to believe that the classical economic definitions of market power and workably competitive markets are appropriate. That is to say, a workably competitive market is one in which a large number of firms compete to produce the same product and no firm is able to raise prices significantly above system marginal costs for a sustained period of time. Conversely, the ISO believes that a market is not workably competitive if a small number of firms have the ability to raise prices significantly above system marginal costs unimpeded by competition from other suppliers, other substitute products, or demand elasticity. The absence of workable competition, or market power, can be measured in many ways, including calculation of HHI indices, the market share of major suppliers, the number of hours a firm can be pivotal, the Residual Supply Index,

[7] *See, e.g.,* the ISO's January 27, 2000 Answer and Reply Comments in Docket No. ER00-703.

and, bid mark-up (or the degree to which Market Clearing Prices exceed the marginal cost of the highest cost source of supply needed to meet demand).

Several parties submit comments that raise issues which the ISO believes are properly addressed in other proceedings or forums. For example, the Oversight Board notes that an ISO study submitted in Docket No. ER00-703 on December 1, 1999 raises questions about the impact of RMR Contracts on Intra-Zonal Congestion and the ISO's "5 percent" criterion for the creation of new Congestion Management Zones. Oversight Board at 4. In a filing submitted in that docket just last week, the ISO restated its commitment to undertake a further study concerning whether and how the costs incurred under RMR Contracts should be taken into account in the ISO's criteria for creating new Zones.[8] The ISO has requested Commission guidance on the proposed methodology for that study.

The Oversight Board also states that the interaction between RMR dispatch and Intra-Zonal Congestion Management should be considered as part of the review of the Congestion Management system that the Commission directed the ISO to initiate in the January 7 Order. The ISO agrees that the use of RMR Contracts to prevent or alleviate Intra-Zonal Congestion is an issue that must be addressed. Indeed, the ISO anticipates that the study it is preparing on RMR costs and the criteria for creating new Zones will help inform whatever process is initiated in response to the January 7 Order.

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8 *Id.*

The CPUC raises questions about the use of RMR Contracts to mitigate market power in the San Diego Basin in the long-term. CPUC at 3. The CPUC suggests that substitutes for RMR Contracts, such as additional generation or transmission upgrades, should be considered and that, to the extent RMR Contracts continue to be used to mitigate market power in the San Diego Basin, the terms of such contracts, including their pricing mechanisms, may need to be re-examined. The CPUC's statements are consistent with two key recommendations of the December 30 Report: (1) that any market design changes, including the possible modification of RMR Contract requirements, be considered in the context of a more detailed analysis of how such proposed modifications might affect and/or mitigate market power in the San Diego Basin; and (2) that market power considerations be incorporated into the analysis of different options for meeting new Load growth in the San Diego Basin, including new transmission capacity, new generation, repowering of existing Generating Units, and demand-side options. *See, e.g.*, Report at 24-25. The ISO also notes that one of the primary goals of the ISO's annual Local Area Reliability Service ("LARS") process, by which Generating Units are designated as RMR, is the identification and selection of cost-effective alternatives to RMR Contracts, such as transmission upgrades or load-based alternatives. The ISO expects to continue to work with the CPUC to address such issues in the future.

Lastly, DWR offers a comment that should be addressed in other proceedings before the Commission. DWR notes that, under revisions proposed and accepted in Amendment No. 23 to the ISO Tariff, the costs for certain ISO "out-of-market" generation dispatch calls are allocated to Participating Transmission Owners ("Participating TOs") and that those Participating TOs have proposed to pass such costs on to their customers. DWR at 4-5. In its Comments on the December 30 Report, DWR requests that the Commission address issues related to the charging of transmission customers for such costs. This request concerns matters well beyond the scope of the December 30 Report, and the Commission should not respond to the request in this proceeding. The proper place for DWR to make such a request is in the FERC dockets for the various Participating TO filings identified in footnote 1 of DWR's Motion to Intervene and Comments.

IV. Conclusion

The ISO respectfully requests that the Commission accept its Answer to Motions to Intervene and Reply Comments and further requests that the Commission accept the "Market Power in the San Diego Basin Addendum to Annual Report on Market Issues and Performance" submitted in compliance with Commission orders.

Respectfully submitted,

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Dated: February 3, 2000

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 docket, 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 3rd day of February, 2000.

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Sean Atkins

ATTACHMENT A

Impacts of RMR and Local Market Power on Intra-Zonal Congestion

The following scenarios are provided to further clarify: (1) the methodology and findings of the Report; (2) several of the fundamental features of California's current market design; and (3) the impact RMR Generation may have on Intra-Zonal Congestion and the exercise of local market power in the Intra-Zonal Congestion Management market. Figure A-1 summarizes the three numerical scenarios used in the following discussion.

Figure A-1

Illustrative Scenarios: Potential Impacts of RMR and Local Market Power on Intra-Zonal Congestion

	Scenario 1	Scenario 2	Scenario 3
	No Congestion (*with* or *without* RMR)	Congestion Avoided due to Local RMR Reliability Requirement	Congestion due to Exercise of Local Market Power (*Without RMR*)
Day Ahead Market			
Total Scheduled Demand in Basin	3,500	3,500	3,500
Generation (in Basin) Scheduled in DA Market	1,500	500	500
DA Demand for Transmission Capacity (into Basin)	2,000	3,000	3,000
Available Transmission Capacity	2,500	2,500	2,500
Excess (or shortage) of Tranmission Capacity into Basin based on DA Schedules	+ 500 (no congestion)	- 500 (congestion)	- 500 (congestion)
Local Reliability Management with RMR			
Local Area Reliability Requirement	1,600	1,600	0
Generation (in Basin) Scheduled in DA Market	1,500	500	0
RMR Schedule Change	100	1,100	0
Real Time Market			
Total Real Time Demand (in Basin)	3,500	3,500	3,500
Total Generation in Basin in Real Time	1,600	1,600	500
Real Time Demand for Trans.Capacity (into Basin)	1,900	1,900	3,000
Available Transmission Capacity	2,500	2,500	2,500
Excess (or shortage) of Tranmission Capacity into Basin in Real Time	+ 600 (no congestion)	+ 600 (no congestion)	- 500 (congestion)
Incremental Generation Called *Out-of-Sequence* from within Basin to resolve Intra-zonal Congestion	0	0	500

Scenario 1: No Congestion (With or without RMR)

This scenario illustrates conditions under which no Intra-Zonal Congestion would occur --- either in the absence of local market power, or, if local market power exists, where it is effectively mitigated by the existence of RMR Contracts. This scenario represents conditions that exist in the San Diego Basin during virtually all hours (as explained and shown in Figure 7 on page 20 of the December 30 Report).

In this example, total area load is 3,500 MW. A total of 1,500 MW of generation within the Basin is scheduled in the Day-Ahead (DA) Market. Thus, the total demand for transmission capacity into the Basin is only 2,000 MW, while the total available transmission capacity is 2,500 MW.[9] Since San Diego is not a Zone, no Day-Ahead Congestion Management is performed. However, even if Day-Ahead Congestion Management were performed for this transmission interface (either by making San Diego a Zone or by instituting Day-Ahead Intra-Zonal Congestion Management), no Congestion would exist on the transmission interface since imports into the Basin are less than the available transfer capability.

After the Day-Ahead Market, the ISO compares the final Day-Ahead Market schedule of each RMR unit to the Minimum Reliability Requirement ("MRR") of each unit. If a unit's MRR is higher than its Day-Ahead Energy schedule, the ISO issues a Schedule change for the incremental amount of generation needed from the unit to meet the RMR Unit's MRR. In the example shown in Scenario 1, for instance, the sum of the MRR for each RMR unit in the area equals 1,600 MW. A total of 100 MW of incremental generation is required to meet each individual RMR Unit's MRR.[10]

As illustrated in this scenario, it is possible to identify conditions under which Congestion would not have occurred (in the absence of both local market power and with no RMR Contracts) by simply comparing the total available transmission capacity to the demand for transmission capacity (or local area demand minus local generation

[9] For mathematical simplicity, we have rounded the available transmission capacity into the San Diego Basin up from 2,450 to 2,500.

[10] Under current ISO protocols, the ISO issues Schedule Changes to RMR Units after the Day-Ahead Market as necessary to dispatch this incremental generation, which appears (unscheduled against any market demand) in real-time.

scheduled in the Day-Ahead Market). As shown in Figure 7 of the Report, this analysis indicates that virtually no Congestion would have occurred in the San Diego Basin (in a theoretical world in which local market power did not exist in the Basin) even if no RMR Generation needed to be "constrained on" by the ISO to meet local reliability criteria.

Moreover, it is important to note that the MRR for each RMR Unit is based directly on the need to meet local area reliability criteria, rather than the need (if any) to mitigate Intra-Zonal Congestion during any given hour. In fact, RMR Generation is not designated for the purpose of mitigating Intra-Zonal Congestion. In most cases, however, the sum of total amount of generation needed to meet each RMR Unit's MRR *exceeds* the total amount of generation that would be required within an RMR area to prevent Intra-Zonal Congestion. Thus, RMR Generation that is "constrained on" to ensure that local reliability criteria are met may in some case prevent Intra-Zonal Congestion that may otherwise occur in real-time in the *absence* of any effort by the ISO to meet local reliability criteria by constraining on RMR units. This situation, which was virtually never found to occur in the San Diego Basin over the recent 12 month period examined in the Report, is illustrated under Scenario 2.

Scenario 2: Congestion Avoided (or Mitigated) by RMR

This scenario illustrates conditions under which Intra-Zonal Congestion could occur for either of two reasons: (1) a shortage of "economic" supply inside the area *(i.e.*, generation which is profitable for generators to scheduled and operate given Market Clearing Prices in the ISO's Southern Zone, SP15); or (2) a shortage of generation scheduled from units inside the area due to exercise of local market power. However, as shown in this example, RMR Generation requirements have the effect of mitigating (or avoiding) both these types of Congestion.

First, Congestion may occur simply because the supply of generation within the Basin that is scheduled through the Day-Ahead Market at the Zonal (SP15) Market Clearing Price is less than the amount of generation needed to meet demand inside the Basin (*i.e.*, total demand minus transmission capacity into the Basin from SP15). In this example, total area load is 3,500 MW (same as Scenario 1), but a total of only 500 MW of generation within the area is scheduled in the Day-Ahead (DA) Market. However, in real-time, Congestion is avoided due to the fact that 1,600 MW of RMR Generation is required. The additional 1,100 MW of RMR Generation that is dispatched (through a schedule change issued by the ISO after the Day-Ahead Market) appears in real-time, so that no Congestion occurs into the Basin.

In this scenario, if generators within the Basin attempt to exercise local market power by withholding capacity (*e.g.*, by not scheduling generation in the Day-Ahead Market even though it would be profitable to do so at market Energy prices, and/or by curtailing in real-time generation by some units that are scheduled in the Day Ahead Market), they cannot profit from this strategy since no Intra-Zonal Congestion occurs due to the level of RMR Generation that is "constrained on". The following scenario (Scenario 3) illustrates how local market power could be exercised in this way if no RMR Contracts or minimum reliability generation requirements existed in the Basin.

Scenario 3: Congestion due to Exercise of Local Market Power without RMR

This scenario illustrates how, in the absence of RMR Contracts, local market power may be exercised to create Congestion (by withholding capacity or curtailing scheduled generation), and thereby force the ISO to call upon very high priced real-time Energy bids out-of-sequence from either of the two major suppliers within the Basin. This scenario is similar to Scenario 2, but assumes that no RMR Contracts or Generation requirements are set for the Basin. Under these conditions, the ISO would need to accept 500 MW of real-time Energy bids submitted by the two major suppliers in the Basin *out-of-sequence* in order to alleviate Congestion. With only two major suppliers inside the Basin, competition to supply the incremental Energy the ISO would need to call out-of-sequence under this scenario would be very limited. Since Energy called *out-of-sequence* from non-RMR units is paid at bid price (rather than the Zonal real-time imbalance price), generators can benefit from exercising local market power in the manner illustrated in this scenario by bidding Energy at a very high price into the real-time market through Supplemental Energy bids and/or through Energy bids that must be submitted for capacity providing Ancillary Services (Spinning, Non-Spinning and Replacement Reserve). In this example, for instance, the two generators within the Basin would sell a total of 1,000 MW less in the Day-Ahead Market at the Zonal Market Clearing Price compared to Scenario 1 (500 MW versus 1,500 MW), but could sell an additional 500 MW at a higher “as bid” price as a result of the ISO’s need to call upon bids out-of-sequence to relieve Intra-Zonal Congestion.