CALIFORNIA ISO

Market Power in the San Diego Basin

Addendum to Annual Report on Market Issues and Performance

Prepared by the Department of Market Analysis

California Independent System Operator

December 1999

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1. Executive Summary

This report provides a preliminary analysis of market power in electric generation in the San Diego Basin, as addendum to the ISO's *Annual Report on Market Issues and Performance*, submitted to FERC in June 1999.

FERC's original request for an analysis of generation market power in the San Diego Basin was grounded in the concern that San Diego Gas & Electric Company would retain its generation assets. Subsequently, the company has divested its generation assets to two unaffiliated generators. Results of this preliminary analysis nevertheless suggest that there remains a significant potential for generation owners in the San Diego Basin to exercise market power. The high concentration of ownership of generating resources in San Diego (with only two suppliers controlling about 90% of the generation sources within the Basin) creates the potential for duopolistic bidding behavior under high load conditions.

Any effort to exercise this market power, however, is currently mitigated by the ISO's Reliability Must Run (RMR) contracts with generation suppliers in the Basin. The ISO's minimum generation requirements for these RMR units, which are set based on local reliability criteria, are generally sufficient to ensure that the demand for electricity in the Basin can be satisfied by a combination of local generation and imports from the broader congestion zone in which the San Diego is located (SP15), without exhausting the available transmission capacity. This limits the ability of generation owners within the Basin to exercise market power by not scheduling generation in the forward markets, and requiring the ISO to call upon high priced bids in the congestion management and/or real time energy markets.

Given the high concentration of supply inside the Basin, we recommend that any major market design changes (such as modification of RMR contract requirements or creation of a new zone) be preceded by more detailed analysis of how market power in the Basin may be affected by any proposed change and what would be appropriate mitigation measures. We also recommend that market power considerations be incorporated into 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. A preliminary examination of each of these options by the ISO suggests that the cost and lead times of many are significant, and that there is no single option that can be readily implemented to ensure that future load growth in the Basin is met. A detailed examination of these options is beyond the scope of this report.

The remainder of this report is organized as follows: Section 2 provides background on regulatory and policy decisions relating to market power in the San Diego Basin. Section 3 provides an overview of demand and supply conditions in the San Diego Basin. Section 4 describes the methodology used in this report to assess market power in the San Diego Basin and presents results of this analysis. Section 5 discusses implications of issues and trends identified in this report.

2. Background

On September 9, 1999, FERC accepted the *Annual Report on Market Issues and Performance* prepared by the ISO's Department of Market Analysis (DMA) for filing, but directed the DMA to submit a report addressing an evaluation of the market in the San Diego Basin by December 31, consistent with Pacific Gas and Electric Company, et al., 81 FERC ¶ 61,122 (1997). In this order, the Commission directed "the ISO and 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". The DMA's *Annual Report on Market Issues and Performance*, submitted in June 1999, provided an assessment of overall market power in the ISO's Ancillary Service markets, but did not specifically address market power in the San Diego Basin[1]

In October 1997, concern about market power in the Basin stemmed primarily from the fact that San Diego Gas and Electric Company (SDG&E) had not yet divested or announced plans to divest its generation assets in this region. The possibility that SDG&E could use its control over generation assets to exercise market power in the region to influence prices in the region presented a significant issue.[2] FERC did not require divestiture as a condition for market-based rates for SDG&E's energy sales in the PX, on the grounds that market power could be adequately mitigated during the transition period by:

- the retail rate freeze, and its influence on SDG&E's likely behavior;
- requirements that energy from generation owned by SDG&E be sold in the PX;
- Reliability Must Run (RMR) Agreements, which covered all units owned by SDG&E in the Basin; and
- market monitoring/enforcement plans submitted by the ISO and PX

As a longer term solution for the San Diego Basin, FERC identified two options with the potential to effectively mitigate market power in the San Diego Basin:

- development of demand-side bidding, and

[1] See Chapter 7 of the *Annual Report on Market Issues and Performance*, prepared by the Market Surveillance Unit (now the Department of Market Analysis) of the California System Operator, June 1999.

[2] The Commission noted that "during the transition period while the retail rate is in effect, the retail rate freeze in conjunction with the CTC will reduce the incentive to raise prices when the [UDCs} are net buyers," but that "when the [UDCs] are net sellers, they may still have an incentive to raise prices, because the increased earnings from the higher-priced sales may outweigh the losses incurred by reducing the CTC." October 1997 Order, 81 FERC ¶ 61,122 at page 61,122.

- divestiture of generation assets

Since October 1997, the nature and implications of market power in the San Diego Basin has been re-shaped due to a number of more recent developments.

- In Spring 1999, virtually all of SDG&E's generation assets within San Diego were divested so that all of these plants are now bid into California's energy market by new participants (Dynegy and Duke Energy).

- In January 1999, SDG&E announced that it would pay off its CTC by July 1999, removing the clear incentive to keep energy prices low that was created by the CTC. In October 1999, a Joint Settlement Agreement was filed with the California Public Utilities Commission (CPUC) in Phase II of SDG&E's Post Transition Settlement Ratemaking Application (99-01-019) under which SDG&E's bundled customers would be charged for energy and ancillary services at specified benchmark prices. These charges would be adjusted based on the difference between actual costs and the pre-established benchmark. The proposal is designed as a Performance Based Ratemaking (PBR) mechanism that is intended to provide SDG&E with an incentive to minimize energy and ancillary service procurement costs, while sharing the potential risks and benefits of the deregulated wholesale energy market between bundled customers and shareholders.

- Demand-side options, cited in FERC's 1997 order as one of the keys to a long-term solution for mitigating market power in the San Diego Basin, have just begun to be developed in California. In November 1999, SDG&E filed a proposal with the CPUC for a Demand Responsiveness program, under which participating bundled service customers would be paid to reduce consumption on days when high prices were expected to occur. SDG&E is proposing to offer the program during the summer months of 2000, after which time SDG&E would evaluate the program and submit an annual report to the CPUC with recommendations to modify or terminate the program.

- Operating experience now indicates that the level of RMR generation dispatched in the San Diego Basin based on local system reliability criteria also has the effect of mitigating market power in the generation market of the San Diego Basin.[3] However, one of the key goals of the ISO grid planning and Local Area Reliability Services (LARS) process is to identify competitive alternatives to current RMR contracts, including potential transmission upgrades, distributed generation or demand-side options that may be able to substitute for RMR for purposes of ensuring local reliability.

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[3] This effect of RMR Generation in the San Diego Basis is discussed in detail in Section 4.5 of this report.

- In the context of the stakeholder process to develop refinements to the ISO's grid planning process, Sempra (SDG&E's parent company) has raised the issue of whether creating a new zone in San Diego would promote development of new generation as an alternative to other options such as transmission upgrades and continued reliance on RMR generation within the Basin. [4]

[4] For instance, in a recent letter to the ISO, Sempra has stated that "one of the alternatives Sempra is investigating involves splitting the SP15 zone into two zones, which would reduce the price muting effects of RMR generation on energy price signals and intrazonal congestion] in SDG&E's service territory. Allowing these generators to receive scarcity rents that would result from a new zone would provide an economically efficient market price signal to induce demand side bidding and the location of new generation within this zone, thereby creating greater generation competition …With zone splitting, generation can effectively compete with transmission."

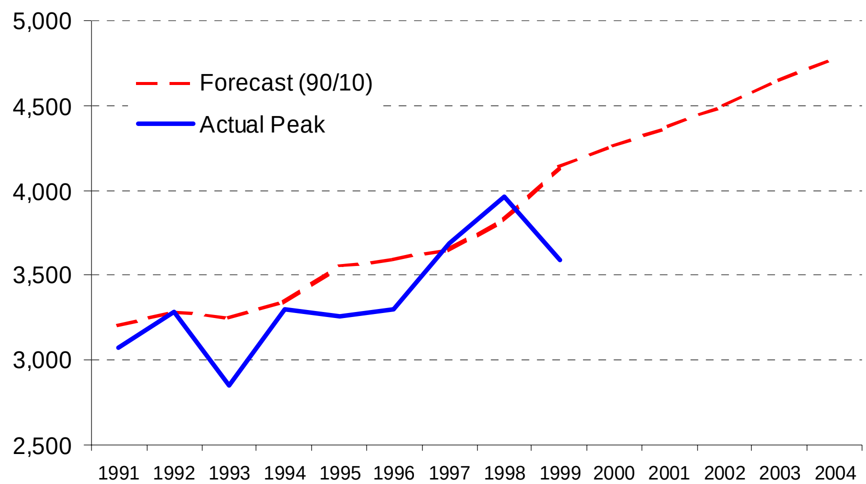
3. Overview of San Diego Basin Electricity Market

3.1 Demand

Load is growing rapidly in the San Diego Basin, with peak loads expected to increase nearly 3% per year over the next few years. Figure 1 compares actual peak loads to SDG&E's "90/10" forecast of peak loads.[5]

The decrease in actual load in 1999 was due to exceptionally cool weather that past summer, which represents the coolest San Diego area temperatures in over 50 years. SDG&E calculates that the weather normalized peak for 1999 (or peak loads that would have occurred under normal weather conditions) was approximately 4,000 MW.

Figure 1. Peak Load Forecast and Actual Loads[6]

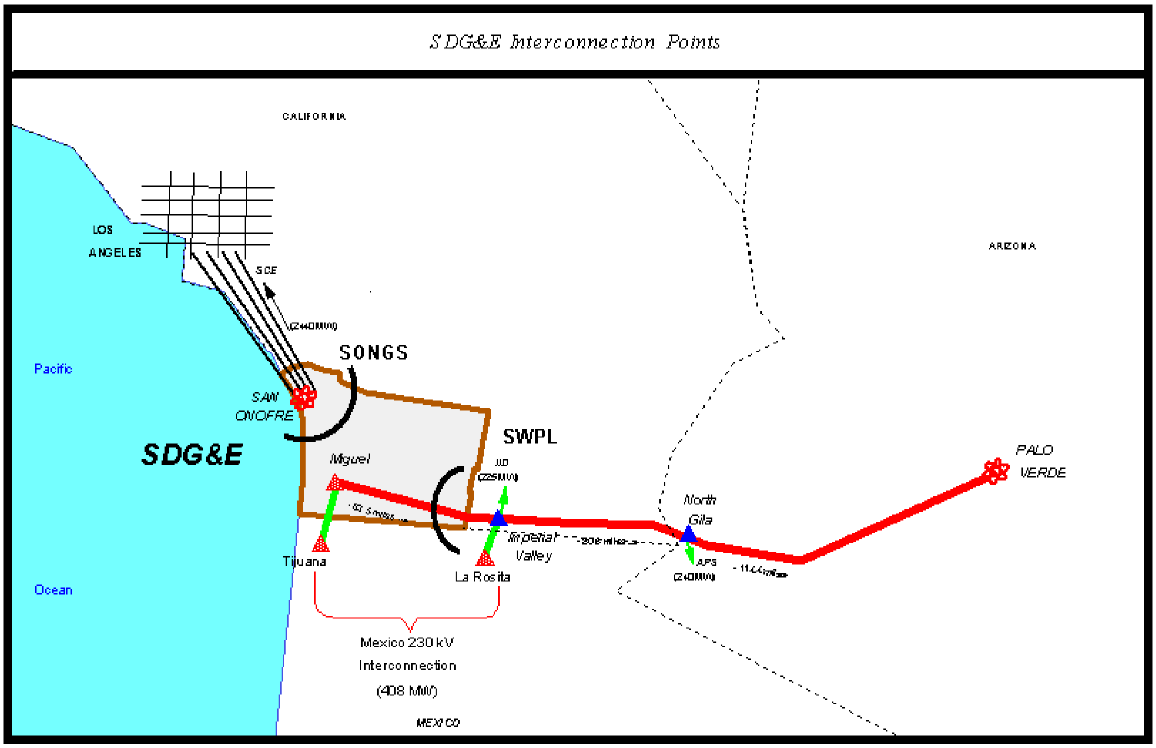


3.2 Imports

Imports into the San Diego Basin play a critical role in meeting demand. The current simultaneous import capability into the San Diego Basin (with all lines in service) is 2,450 MW. The simultaneous import limit (SIL) is defined by the ability to import power via a 500 kV Southwest Power Link (SWPL) and five 230 kV lines south of the San Onofre Nuclear Generating Station (SONGS), which link this source of generation to the San Diego Basin (see Figure 2).

[5] "90/10" forecasts based on weather conditions expected to be exceeded only once in ten years.
[6] Source: SDG&E 1999 Grid Planning Assessment, Version 1.0 October 13, 1999.

Figure 2



The non-simultaneous import capability used to represent a critical *N-1* contingency in Reliability Must-Run (RMR) planning studies and daily RMR dispatch decisions is 1,900 MW. The non-simultaneous import limit of 1,900 MW is based on the available capacity for importing power via the five 230 kV lines south of SONGS when the SWPL is out of service.

In SDG&E's *1999 Grid Planning Assessment*, SDG&E has proposed several transmission projects that may allow the maximum available transmission capacity to be increased from 2,450 to 2,650 MW by June 2000, and increase further to 2,850 MW in June 2002. According to SDG&E, increases beyond this level will require some type of major transmission upgrade, such as a 500kV project proposed for study by SDG&E in November 1999.

In November 1999, SDG&E announced its intent to study a new 500kV interconnection project with a target in-service date of June 2004. SDG&E estimates that such a project could increase their import capability by another 600 to 1,000 MW.

3.3 Generation

Table 1 provides summary data on the major thermal generation capacity within the San Diego Basin. All major generating units in the San Diego Basin (excluding QF's) have been designated as RMR units. This designation is based on the ISO's determination, in its application of the RMR criteria approved the ISO Governing Board, that the full output of all these units would be needed to meet local demand under adverse peak load conditions, combined with transmission and generator contingencies (i.e. the outage of the SWPL line and one of the larger generating units within the San Diego Basin).

SDG&E's 1999 Grid Planning Assessment was based on the assumption that no new generation would be on-line within the San Diego Basin over the 2000-2004 time period covered by this study. For purposes of transmission planning, however, SDG&E only takes into account plants that are constructed or licensed, and have an interconnection agreement with SDG&E. No attempt was made in this report to forecast new merchant power plants that could come on-line in this time period, or the potential for repowering of existing plants in the basin.

PG&EGen (an unregulated affiliate of PG&E) has filed with the California Energy Commission (CEC) to obtain a license to build a 510 MW natural gas-fired combined cycle power plant. The ISO expects that this plant could be operational by late 2002.[7] The plant would built in the Otay Mesa area in western San Diego County, about 15 miles southeast of San Diego, California, and about 1.5 miles north of the United States/Mexico border. A new 230 kilovolt (kV) switchyard at the site is proposed, and PG&EGen plans to build a 0.1-mile connection to SDG&E's existing 230 kV Miguel -Tijuana transmission line that passes near the eastern boundary of the Otay Mesa site.

Beyond the Otay Mesa project, there are no other proposals for new generation capacity that may come on-line within the San Diego Basin within the next few years. Air emissions and other siting constraints within the San Diego Basin present significant barriers to entry in this market.

[7] See Application for Certification (99-ATC-5) filed August 2, 1999 with the California Energy Commission.

Table 1. Generating Resources in San Diego Basin

	Maximum Operating Level	Minimum Operating Level	Variable Fuel Cost [1] Minimum Level	Mid-Point [2]	Maximum Level
Units Bid Into Market by Dynegy					
Encina Unit 5	330	20	$50.93	$28.15	$26.27
Encina Unit 4	300	20	$48.23	$29.13	$27.08
Encina Unit 3	110	20	$33.51	$30.29	$27.90
Encina Unit 2	105	20	$33.36	$31.08	$28.04
Encina Unit 1	104	20	$34.38	$30.01	$28.30
Kearny Power Block Gas Turbines	59	0	$53.19	$53.19	$116.50
Kearny Power Block Gas Turbines	61	0	$55.84	$55.84	$130.37
Miramar Gas Turbine	36	0	$41.54	$41.54	$42.97
Division Naval Station Gas Turbine 1	22	0	$46.77	$46.77	$37.06
North Island GT 2	18	0	$54.84	$54.84	$41.55
North Island GT 1	18	0	$54.84	$54.84	$41.55
Division Gas Turbine 1	14	0	$53.75	$53.75	$41.61
El Cajon	15	0	$55.75	$55.75	$43.93
Kearny Gas Ky1 Gas Turbine	16	0	$53.81	$53.81	$41.96
Encina Gas Turbine Unit 1	15	0	$43.92	$44.31	$43.92
Naval Training Center Gas Turbine	15	0	$56.08	$56.08	$42.32
Dynegy Total	**1,238**				
Units Bid Into Market by Duke [3]					
Southbay Unit 4	222	45	$34.53	$31.85	$30.86
Southbay Unit 3	175	30	$32.07	$27.37	$25.65
Southbay Unit 2	150	30	$30.33	$27.07	$25.11
Southbay Unit 1	146	30	$31.15	$27.47	$25.47
Southbay Gas Turbine 1	15	13	$37.52	$37.13	$36.07
Duke Total	**708**				
Other (SDG&E, QF contracts, etc.)	**174**				
Total Capacity	**2,120**				

[1] Fuel operating costs based on generation owners' RMR filings with FERC, assuming heat rates corresponding to different operating levels indicated in the table and $2.50/MBtu gas cost.

[2] Mid-point between minimum operating level and maximum operating level.

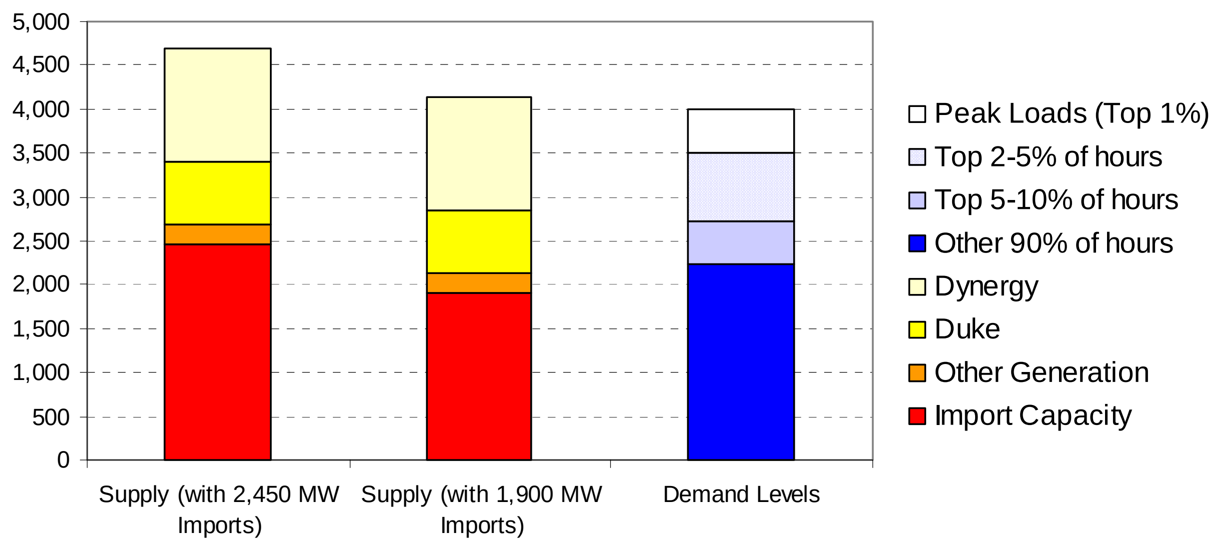
[3] Includes plants owned and/or operated by Duke.

3. 4 Load and Supply Resources Balance

Figure 3 compares maximum supply sources in the San Diego Basin to load levels estimated to have occurred in 1999 under normal weather conditions.[8] As shown in Figure 3, the balance between loads and resources is relatively close for the top 5% to 10% load levels that could be expected under normal weather conditions. During these peak load hours, the largest supply bidder (Dynegy/NRG) is likely to be pivotal, i.e. total demand cannot be met without some of this supplier's capacity. The amount of available transmission capacity for imports also plays a key role in the degree of market power that suppliers within the San Diego Basin may have.

Figures 4 and 5 provides a profile of the load duration curve for the San Diego Basin over the 12 month period from November 1998 through October 1999 that was used in this study. The following section provides a more detailed discussion of market power in the Basin under different load, supply and transmission conditions.

Figure 3. Load and Supply Resources



[8] Based on actual hourly loads from November 1998 through September 199, adjusted upwards by approximately 10% to reconcile actual observed peak with estimated peak of 4,000 MW under normal weather conditions.

Figure 4. Load Duration Curve (Nov 1998-Oct.1999)

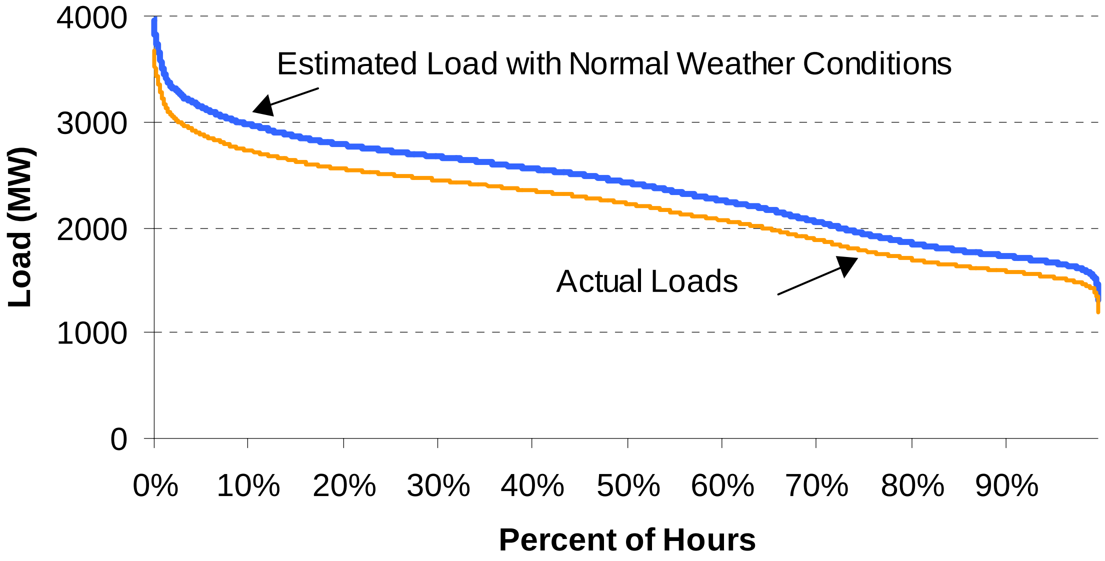
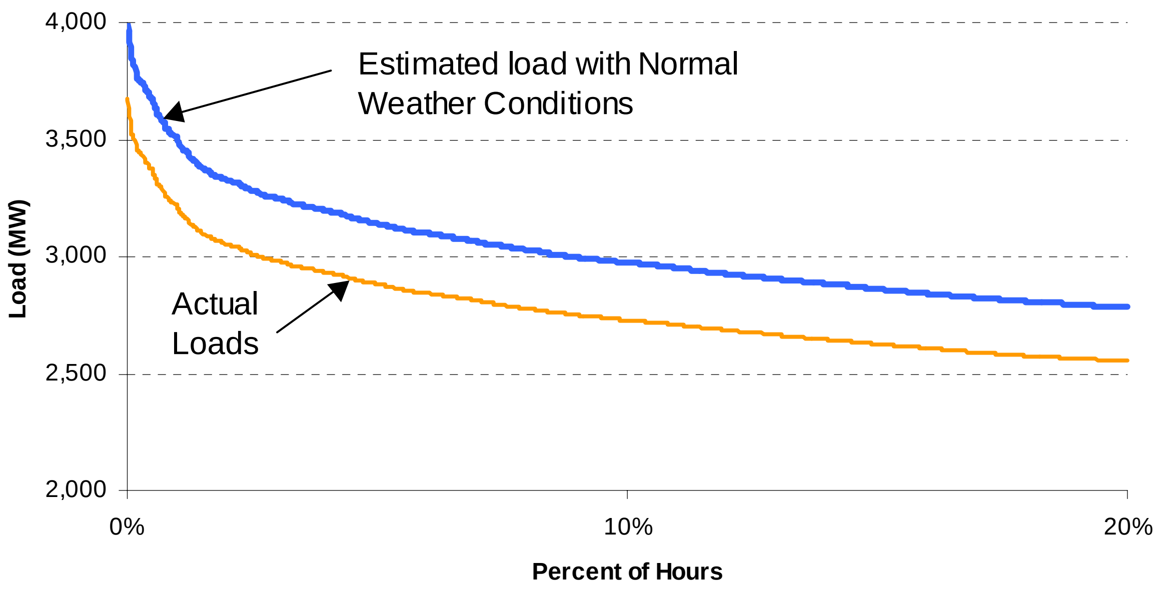


Figure 5. Load Duration Curve
(Top 20% Load Levels - Nov 1998 to Oct.1999)



4. Assessing Market Power in the San Diego Basin

4.1. Overview of Methodology

To assess market power in the San Diego Basin, this study begins by determining whether the market in that area is workably competitive. The classical economic definition of 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 time period. There is market power if there is the ability to raise prices significantly above system marginal costs unimpeded by competition from other suppliers, other substitute products, or demand elasticity. A workably competitive market produces market prices which are reasonably close to system marginal cost, i.e. the highest cost unit to serve the demand. The absence of workably competitive markets can be measured in many ways including calculation of HHI indices, determination that a firm has more than a 20% market share, the number of hours a firm can be pivotal, the Residual Supply Index (discussed below), and, the most conclusive measure, bid-mark-up. This study employs the following three-step approach:

1) Define the relevant geographic markets and product markets and estimate the frequency of each market condition.

a) Define the geographic market. The boundary of the markets often depends on transmission congestion conditions. There may be more than one relevant market under various congestion conditions.

   In San Diego basin, for example, there may be no congestion on the importing interface into the basin or on path 15 or 26 for majority of the hours in a year. Under this no congestion condition, San Diego basin is part of a large geographic market which encompasses the entire California ISO market. When there is congestion on the importing interface into the basin, San Diego becomes an island separated from SP15 zone.

b) Define the product. There are many energy generation and ancillary service products traded in the California ISO and PX markets. Assessment of market power can be performed separately or combined for any of these products.

2) Perform market power screening – In each relevant geographic market/boundary selected in step 1, a market power screen is applied as follows:

(a) The Residual Supply Index (RSI) profile is computed for the geographic market/boundary under consideration. This profile consists of the minimum RSI for each supplier for each hour over certain time period (e.g., a year).

RSI is a measure of supply sufficiency when a large supplier's capacity is taken out of the market. If RSI is high, the remaining suppliers can adequately provide the product to the market and the large supplier has limited market power. Section 4.3 defines the exact formula used to calculate the RSI.

(b) From the RSI profile, the number of hours where the RSI exceeds a given threshold (e.g., RSI>1.0 or RSI>1.2) is recorded for the relevant geographic market/boundary as a percentage of the total number of hours of the RSI profile. This percentage frequency represents the percent of hours when the market may be workably competitive in the relevant geographic market/boundary. Its complement (100% minus the frequency of workable competition) represents the percent of hours when market are not workably competitive.

(c) If the frequency of workable competition exceeds a certain pre-specified threshold, the relevant geographic market/boundary is considered to be workably competitive. The reasonable thresholds presently considered are 99.5% of the time with RSI>1.0 or 95% of the time with RSI>1.2. An equivalent measure is RSI < 1.0 for less than .5% of the time or RSI < 1.2 for less than 5% of the time. This gives a measure of the number of hours a supplier could be pivotal in the market and could set prices at high levels or without constraint.

3) In-depth study of market power

A geographic market/boundary that does not pass the RSI screen test in step 2 (e.g., RSI<1.2 more than 5% of the time, or RSI<1.0 more than 0.5% of the time) must be subjected to further scrutiny. This is because the risk of unworkable competition in this case exceeds the acceptable threshold. The in-depth study of market power in each relevant market will involve computation of bid price markup using market simulation techniques. Market simulation models addressing bidding behavior and market power is currently under development at DMA and is not applied to this study.

4.2. Defining the Relevant Market

4.2.1. Geographic Market

The geographic market under consideration is limited to the San Diego Basin. The San Diego Basin represents a relatively small portion of the southern zone of the ISO system (SP15), which accounts for about one-fifth of the peak demand, and only about 10% of the supply resources within SP15.

For purposes of this analysis, the geographic market is defined as the portion of the San Diego Basin depicted in the shaded area of Figure 2, taking into account available imports of 1,900 to 2,450 MW (depending on the status of SWPL).

Typically, a key step in defining the geographic boundaries to be used in assessing market power involves reviewing the frequency of congestion on the transmission grid. When congestion is present, the ability of generation owners to exercise market power is often increased, since supply from outside the congested area is constrained at a level that requires all residual demand (i.e. total demand minus the amount that can be imported given transmission constraints) to be met by supply resources within the constrained area. In California, ownership of supply resources is much more concentrated within each local sub-zone than within each congestion zone itself. Within smaller local sub-zones (such as the San Diego Basin and numerous other RMR areas), supply is extremely concentrated, with just two major suppliers.

Direct historical data on congestion into the San Diego Basin does not exist for several reasons. First, since San Diego is not a separate zone, no inter-zonal congestion management is performed for the San Diego Basin. Second, any potential intra-zonal congestion into San Diego in real time is prevented from occurring due to RMR minimum generation requirements that are set for suppliers within the Basin under RMR contracts based on local reliability criteria.

Minimum generation requirements for RMR are set to ensure the sufficient generation is in operation within the San Diego Basin to maintain local system reliability in the event of transmission contingency (*T-1)* under which only 1,900 MW could be imported into the Basin from SP15. Although these RMR generation requirements are based on local reliability criteria (rather than on the any need to mitigate intra-zonal congestion), the fact that RMR generation requirements are set in this manner has the effect of preventing real time intra-zonal congestion from occurring whenever the full simultaneous transmission capacity of 2,450 is available.[9]

[9] These minimum generation requirements also have the indirect effect of mitigating any potential for the exercise local market power by not scheduling generation in the Day Ahead energy market, in order to be called “out-of-merit order” at a significantly higher bid price through the ISO intra-zonal or inter-zonal congestion management market.

A more detailed discussion and analysis of congestion and minimum generation requirements set under RMR contracts as these factors relate to market power in the San Diego Basin are presented in Sections 4.3 and 4.4 of this report.

4.2.2. Defining the Product

In California's electricity market, different sub-markets may be defined, including the Day Ahead and Hour Ahead markets for energy, inter-zonal congestion management, Ancillary Services, and real time energy. Given the sequential nature and the interrelationships among these markets, overall market power must be assessed taking all of these markets into account. In this study, we examine overall market power based on the combined overall demand and supply of generating capacity in these different markets each hour.

With this approach, total demand is defined based on total energy load plus additional capacity needed for the following Ancillary Services: upward regulation, spinning reserve, non-spinning reserve and replacement reserve. During peak hours, demand for these Ancillary Services typically represents at least 10% of total loads. [10]

4.3. Screening for Market Power with the Residual Supply Index

The ISO's Department of Market Analysis employs a two-part approach for assessing market power, in which the potential for market power is first screened using the Residual Supply Index (RSI). If this analysis indicates that market power may exist, a more detailed analysis based on other indicators of market power should be performed prior to implementing any policy or market design changes, which may be designed on the premise that a specific market is workably competitive.

The RSI for a market is defined as the ratio of residual supply (i.e. the supply that would be available if the largest single supplier chose to withhold its capacity or bid this capacity at prices significantly higher than costs) to total demand:

$$\frac{\text{Import Capacity}_t + \text{Internal Generation from Other Suppliers}_t}{\text{Demand}_t}$$

The RSI should be viewed as an indicator for the potential for the largest supplier in a market to exercise market power. When the RSI is substantially above 1.0, the largest supplier would be unlikely to profit by withholding its capacity (or bidding capacity significantly in excess of actual marginal costs). When the RSI is

[10] In this analysis, the demand for A/S capacity within the San Diego Basin each hour was defined as 10% of the amount of generation within the Basin needed to meet demand assuming imports of 2,450 MW (i,e. Max [0, (Demand – 2,450) x .10] .

near or below 1.0, that indicates a high potential for the exercise of market power, warranting further study prior to implementing any policy or market design changes based on the premise that a specific market is workably competitive. A more detailed discussion of the RSI and results from applying this measure of market power to the ISO's Ancillary Service markets are provided in Chapter 7 of the *DMA's Annual Report on Market Issues and Performance*, to which this report is an addendum.

When historical bid data are available, the RSI may be applied for specific markets based on actual bid data. The RSI may also be calculated after excluding supply bids significantly above marginal costs (or opportunity costs of capacity in other markets) to provide an better indication of the competitiveness of markets. In this study, however, historical bid data were not utilized due to several factors:

- **Portfolio Bidding in PX Energy Market**. Supply resources are bid into the PX energy market as resource portfolios, rather than individual generating units. Since the resource portfolios of suppliers in the San Diego Basin include units inside and outside of the Basin, actual PX bid data for resources in the Basin are not available.

- **RMR Contracts**. As noted above, all major units in the San Diego Basin are under RMR contracts, and a significant portion of this capacity is dispatched under RMR contracts during high load conditions. We expect bidding to be affected significantly by RMR contracts.

Rather than relying on historical bid data, the Residual Supply Index was calculated based on Monte Carlo simulations of hourly supply, demand, and transmission capacity. The methodology used in this preliminary analysis is summarized below.

- **Demand.** Demand in the San Diego Basin was estimated by first taking actual observed demand for the 8760 hours over the 12 month period from November 1998 through October 1999 (see Figures 4 and 5). These actual hourly demand levels were then scaled up to reconcile the actual observed peak with the peak load of about 4,000 MW that would have occurred in 1999 under normal weather conditions according to SDG&E planning staff. Finally, total demand for generation was adjusted to account for the additional demand for Ancillary Services that would be procured from generation sources within the San Diego Basin to ensure system reliability if the Basin were treated as a separate congestion zone.[11]

[11] The demand for A/S capacity within the San Diego Basin each hour was defined as 10% of the amount of generation within the Basin needed to meet demand. For instance, during hours when transmission capacity equals 2,450 MW, demand for Ancillary Services that should be met through resources inside the Basin equal Max [0, (Demand – 2,450) x .10] .

- **Import Transmission Capacity.** The current maximum capacity of 2,450 MW was assumed to exist during 99% of hours, with only 1,900 MW being available due to unplanned line outages during the other 1% of hours. The 1% of hours when transmission was limited were randomly assigned throughout the year in a series of Monte Carlo simulations.

- **Internal Generation.** A maximum of 2,120 MW of generation was assumed (see Table 1), with each unit having a 2% forced outage rate. The 2% probability that each unit would be unavailable due to forced outages was randomly assigned throughout the year in a series of Monte Carlo simulations. It was assumed that planned maintenance of units was scheduled one unit at a time during January to May, and October to December, so that all capacity is available during peak months of June to September.

A series of 500 simulations were performed, with generation outages and transmission limitations being varied randomly in each simulation. Results of these simulations were then ranked based on the number of hours when the RSI was less than 1.0 in each simulation.

Figure 6 depicts the duration curve of the RSI for simulations representing the range of simulation results. Table 2 shows the number and percent of hours in which the RSI was less than a specified value. These data show that RSI levels are below one in about one percent of the hours, and they are close to one a significant portion of the year. During those hours, there is the potential for market power to be exercised.

Figure 6. RSI Duration Curves
(Hours with Lowest 10% RSI Values Only)

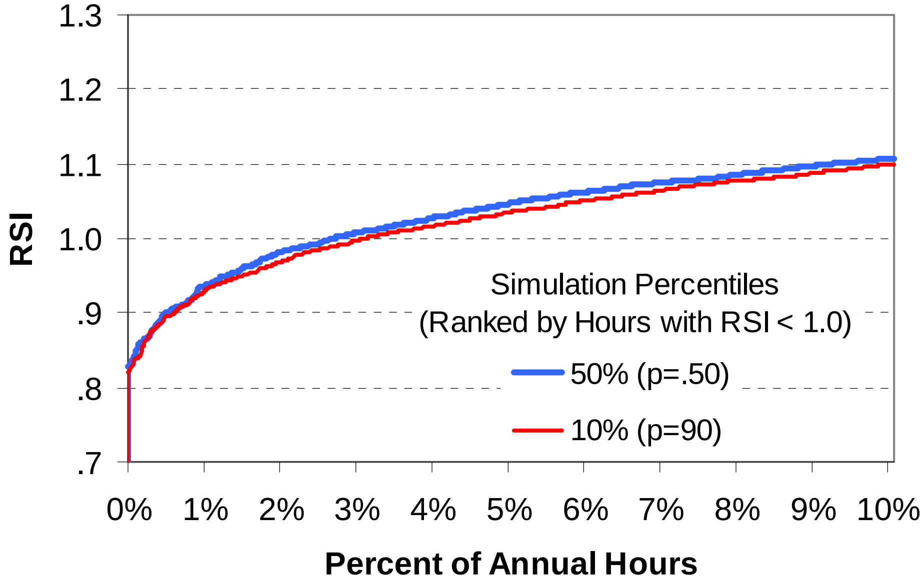


Table 2. RSI Simulation Results

RSI	50th Percentile (Probability = 50%) Number of Hours	Percent of Hours	10th Percentile (Probability = 90%) Number of Hours	Percent of Hours
< .90	42	.5%	39	.5%
< .95	114	1.3%	121	1.4%
< 1.00	229	2.6%	285	3.2%
< 1.05	452	5.2%	495	5.6%
< 1.10	803	9.2%	884	10 %
< 1.15	1,348	15 %	1,443	16 %
< 1.20	2,053	23 %	2,128	24 %

4.4. Potential for Congestion in San Diego Basin

Congestion often coincides with conditions that create opportunities for the exercise of market power. When congestion occurs, supply from outside the congested area is constrained at a level that requires all residual demand (or total demand minus the amount that can be imported given transmission constraints) to be met by supply resources within the constrained area. In California, ownership of supply resources is much more concentrated within each congestion zone. Within most local sub-zones (such as the San Diego Basin and other RMR areas), supply is extremely concentrated, with only two major suppliers.

As noted above, direct historical data on Day Ahead congestion into the San Diego Basin does not exist since San Diego is not a separate zone, and no inter-zonal congestion management is performed for the San Diego Basin. However. for purposes of this study, the potential for congestion in the Day Ahead market was examined by comparing total demand in San Diego to the total generation scheduled in the Day Ahead market by generators within the basin. With this approach, the demand for transmission into the Basin was estimated based on the amount by which total demand exceeds the amount of generation scheduled in the Day Ahead market:

$$\text{Demand for Transmission}_t = \text{Total Demand}_t - \sum \text{Scheduled Generation}_t$$

Where:

Total Demand $_t$	=	The maximum of Day Ahead demand scheduled in San Diego, or actual metered demand in San Diego. Although results were not found to be sensitive to which measure of demand is used, the maximum of these two hourly values was used to ensure demand was not underestimated.
Scheduled Generation$_t$	=	The Day Ahead schedules submitted by all generating units in the San Diego Basin after the Day Ahead market. It should be noted that this does not include additional market energy generated in the real time market as a result of real time energy dispatches or uninstructed deviations. Nor does this include additional non-market energy generated as a result of an RMR dispatch (or schedule change) issued after the Day Ahead market.

The analysis was based on the most recent 12 months of data available, which encompassed the period from November 1, 1998 through October 31, 1999.

Results of this analysis are summarized in Figures 7 and 8. As shown in Figure 8, the potential for congestion when the full 2,450 MW of transmission capacity into the San Diego Basin are available appears relatively limited. Of the 12 months used in this analysis, the difference between total demand and generation scheduled in the Day Ahead market within the Basin exceeded the 2,450 MW level during only 5 hours. During about 14% of hours the potential demand or generation exceeded the 1,900 MW level, representing the *N-1* contingency used in RMR planning and setting minimum generation requirements.

Figure 7. Potential Day Ahead Demand for Transmission Capacity

Estimated Based on Day Ahead Demand minus Day Ahead Supply Schedules within San Diego Basin

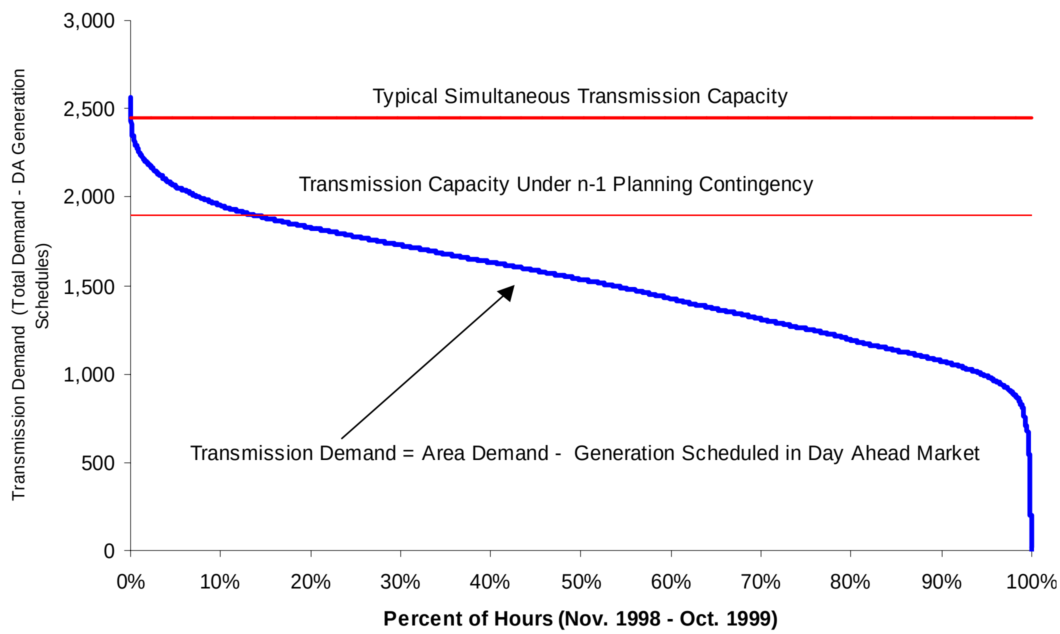
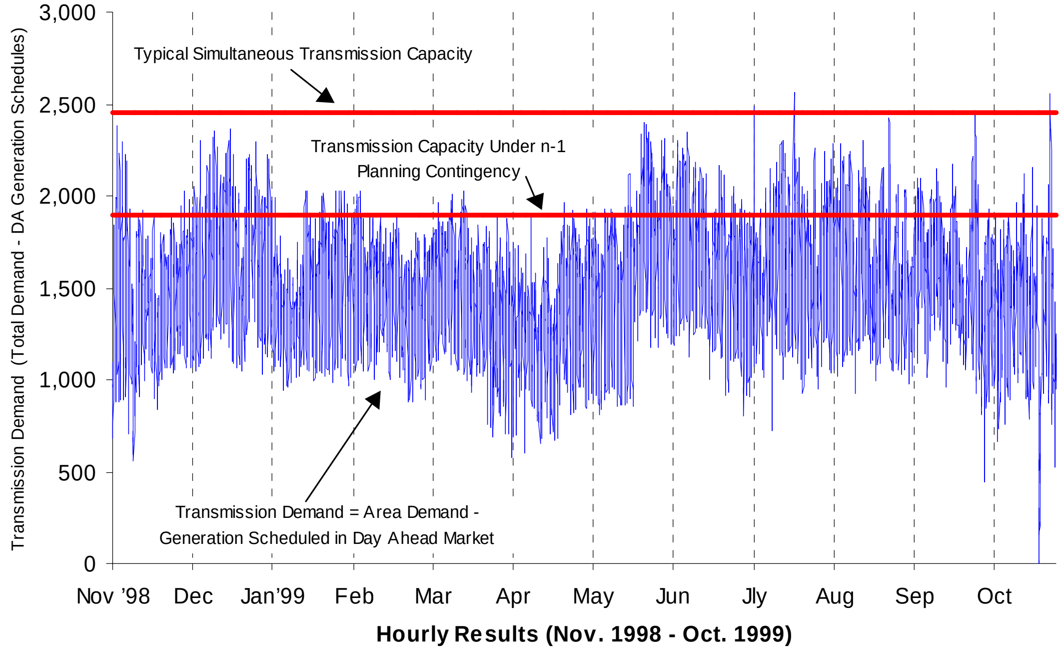


Figure 8. Potential Day Ahead Demand for Transmission Capacity
Estimated Based on Day Ahead Demand
minus Day Ahead Supply Schedules within San Diego Basin



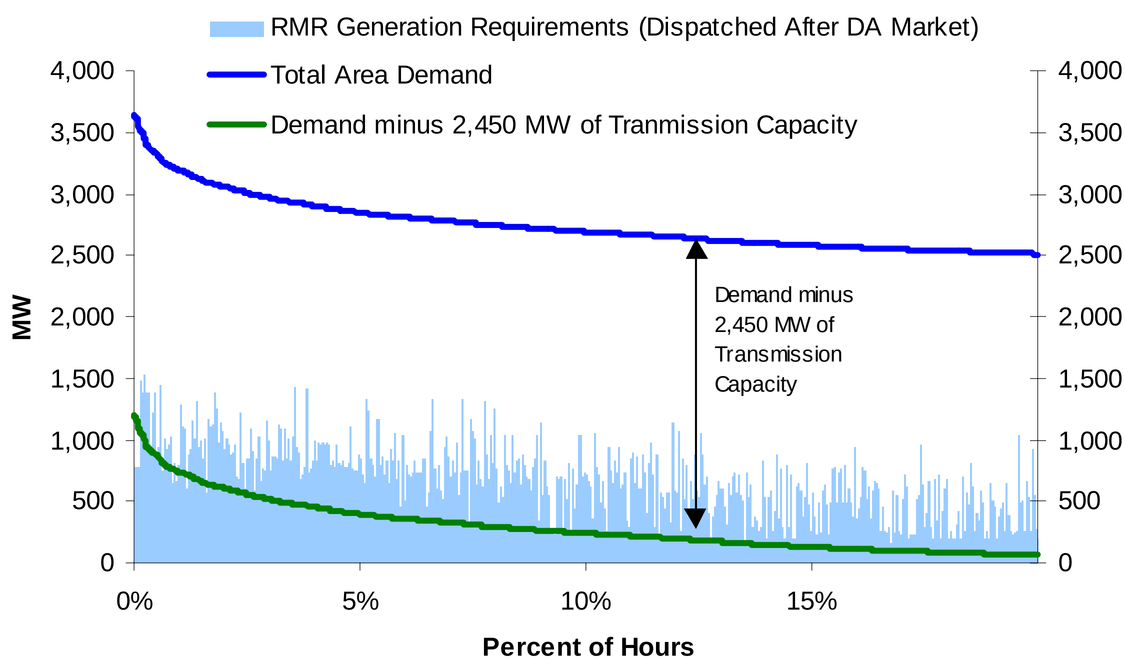
4.5. Impact of RMR Minimum Generation Requirements on Real Time Congestion and Market Power

As a result of the ISO's calling on RMR Units in the San Diego Basin to operate at minimum generation levels for local reliability, real-time intra-zonal congestion into San Diego is prevented from occurring. The minimum generation levels for local reliability are set to ensure that sufficient generation is in operation within the San Diego Basin to maintain reliable system operation in the event of transmission contingency (*N-1)* under which only 1,900 MW could be imported into the Basin from other portions of the SP15 Zone. Although these RMR generation requirements are not set to mitigate congestion, they have the effect of preventing real time congestion from occurring whenever the full simultaneous transmission capacity of 2,450 MW is available.

Figure 9 illustrates the impact of RMR Units' operation at minimum levels necessary to maintain local system reliability in terms of mitigating any real time congestion. Figure 9 compares the total amount of minimum generation requirements set by the ISO under RMR contracts to the total demand in the San Diego Basin, as well as to the minimum portion of demand that must be met by generation within the Basin, after accounting for potential imports from outside the Basin. Results are shown for two levels of potential transmission capacity:

the 2,450 MW that are usually available, and 1,900 MW that are available if an outage occurs on SWPL.

Figure 9. RMR Generation Requirements compared to Total Area Demand (Highest 20% Hourly Loads)



As shown in Figure 9, minimum generation requirements for RMR units issued after the Day Ahead market based on expected load conditions virtually always equal or exceed the amount of demand that would need to be met by generation inside the Basin under typical conditions, with 2,450 MW of transmission capacity available.

Thus, current RMR requirements mitigate the potential for generation suppliers within the San Diego Basin to exercise local market power in the real time intra-zonal market. Any adjustments to the Day Ahead market schedules necessary to meet each unit's RMR requirements are currently issued after the Day Ahead market, and virtually all of this energy appears, unscheduled against demand, as "must-run" energy in the real time market. Without RMR generation requirements, however, under certain load conditions generators may find it most profitable not to schedule generation in the forward markets, and, instead, submit very higher priced supplemental or adjustment bids. If generation within the Basin were insufficient to meet demand (less available transmission capacity), the ISO would need to call this generation out of merit order, and pay the high bid price to relieve intra-zonal congestion.

Results of this report suggest that the San Diego Basin does not meet either of the two key criteria used by the ISO to determine if new zones may be created: the occurrance of significant intra-zonal congestion, and existence of workable competition within the new zone. However, if a new congestion zone were created in San Diego, RMR contracts would continue to be needed to mitigate market power under the current supply and demand balance. Under this scenario, generation owners within the Basin may be able to create congestion in the forward Day Ahead inter-zonal market by not scheduling generation in the Day Ahead markets, even when market prices exceed the variable operating costs of this capacity. Due to available RMR generation, however, the major buyer in San Diego (SDG&E) would be able to "defend" against any effort by suppliers to exercise market power in the Day Ahead market by simply not scheduling in the Day Ahead any portion of its expected demand that significantly exceeds available transmission capacity, and/or submitting relatively low priced demand adjustment bids for use in resolving inter zonal congestion.

Under either of these two responses, any demand that could not be met at competitive prices through imports from the broader SP15 market would appear in the real time market as an energy imbalance. The major buyer in San Diego could rely on the fact that due to RMR minimum generation requirements, the total amount of supply available in the real time market would be sufficient to meet demand, so that no inter-zonal congestion would typically occur in real time. As a result, any imbalance due to a shifting of demand into real time would typically be met at the overall system price or the SP15 price in the event of congestion on Paths 15 or 26.

Under tariff changes being considered by the ISO for filing with FERC, RMR dispatches would be issued prior to the Day Ahead market, and new protocols would be established to ensure that the bulk of this energy is scheduled against demand in the Day Ahead market. With these tariff changes (often referred to as "pre-dispatch" and "netting out" of RMR from the Day Ahead market), most of the incentive for the strategic bidding by suppliers and buyers described above would be eliminated, since the amount of RMR generation scheduled in the Day Ahead market plus transmission capacity would typically be sufficient to avoid congestion.

Another important tariff change to mitigate locational market power has been filed under Amendment 23, and awaits FERC's decision. This Amendment would remedy serious gaming opportunities that exist under non-competitive market conditions whereby a participant with local market power could schedule in the forward market so as to create intra-zonal congestion. When a lack of competition exists in the adjustment bid market on either side of an intra-zonal interface, generators can create intra-zonal congestion and then submit excessively high (e.g. $750/MWh) incremental bids or excessively low (e.g. -$750/MWh) decremental bids to alleviate the congestion. Amendment 23 would allow the ISO to call such resources out-of-market under these conditions for a fair compensation that includes a combination of verifiable cost-based components (start-up cost and gas imbalance charges), and energy and capacity payments (based on competitive market indices for three most recent similar days).

5. Summary Discussion of Results

Results of this analysis suggest that there is a significant potential for local market power to be exercised by generation owners in the San Diego Basin, but that incentives to exercise this market power are successfully mitigated by the ability of the ISO to call on generators within the Basin under RMR Contracts to operate at minimum generation levels to meet local reliability criteria. As a result, generators bid sufficient quantities into the market at competitive prices to avoid congestion into the San Diego area. These findings are consistent with our expectation that, given the operating costs of generation resources in the San Diego area relative to prices in the ISO's southern zone (SP15), we would expect the frequency of congestion to be low in the absence of any exercise of market power.

Without the mitigating effect that RMR generation requirements have on the ability to exercise market power, bidding behavior could be radically different. The residual supply analysis presented in this report indicates that market power could frequently be exercised if RMR contracts or other market power mitigation mechanisms were not present. Based on the analysis presented in this report, we found that the RSI could be expected to fall below 1.0 for 2.6% of the time (or 229 hours per year). In these hours, one of the two major suppliers in the Basin is pivotal and could set the price at any level. During nearly 23% of hours the RSI was found to be between 1.0 and 1.2 , a range where we would expect serious market power concerns, particularly given the high concentration of ownership of supply resources in the Basin.

The high concentration of ownership of generating resources in San Diego (with only two suppliers controlling about 90% of the generation sources within the Basin) creates the potential for duopolistic bidding behavior under high load conditions. Potential transmission upgrades, as well as the proposed addition of a 510 MW plant by a third supplier (PG&EGen) may significantly reduce opportunities for the exercise of market power and may also help ensure local reliability during super peak loads. However, given the rapid load growth and the high concentration of supply inside the Basin, we recommend that any major market design changes (such as modification of RMR contract requirements or creation of a new zone) be based on more detailed analysis of how market power in the Basin may be affected and mitigated under different market design rules.

We also recommend that market power considerations be incorporated into 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 preliminary examination of each of these options presented in this report suggests that the cost and lead times of many are significant, and that there is no single option that can be readily implemented to ensure that future load growth in the Basin is met. Finally, results of this report suggest that the San Diego Basin does not meet either of the two key criteria used by the ISO to determine if new zones may be created: the occurrence of significant intra-zonal congestion, and existence of workable competition within the new zone.