THE UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)))	**Docket No. ER00-___-___**

Declaration of Kellan Fluckiger

State of California)
)
City of Folsom)

I, Kellan Fluckiger, declare as follows:

1. My name is Kellan Fluckiger and I am the Vice President of Operations for the California Independent System Operator Corporation ("ISO"). My business address is 151 Blue Ravine Road, Folsom, CA 95360. As the Vice President of Operations, I am responsible for all aspects of ISO markets and operations, such as dispatching, scheduling, operations engineering, market operations, system planning and outage coordination.

2. The purpose of this affidavit is to discuss the manner in which the ISO's current practices for the dispatch of Reliability Must-Run ("RMR") Generation affect ISO operations.[1] To put it most simply, the ISO can operate the ISO Controlled Grid most efficiently and effectively when decisions on scheduling and commitment of RMR resources are made through Day-Ahead and Hour-Ahead Schedules, and when Market Participants adhere to those schedules. The current procedures for RMR Dispatch preclude this advance coordination, and instead force the ISO to rely upon Real Time directions to

[1] In this affidavit, I use capitalized terms in the sense given in the Master Definitions Supplement to the ISO Tariff.

Generators and Operators of Load, and their prompt and correct response to those directions, to balance Load and Generation. These practices raise the cost of operating the ISO Controlled Grid and increase reliability risks.

3. To make clear why this happens it may be useful to revisit how RMR Dispatch is done currently (I will explain later in my affidavit how the current practice developed). In the Day-Ahead time frame (that is, the day before the operating day), the California Power Exchange ("PX") runs an Energy market between 7:00 and 9:00 a.m. All market participants, including RMR owners, may bid into that market at any price they wish. The megawatts that clear this market are given to the ISO as individual unit schedules at 10:00 a.m. In addition, bilateral arrangements into, within or out of the control area and trades between Scheduling Coordinators are also submitted to the ISO at 10:00 a.m., so that the ISO has an initial picture of Load and Generation Scheduled in the Day-Ahead Market.

4. The Congestion Management process is then run, revised schedules are submitted, and the Congestion Management process is run again on the revised schedules, so that by 1:00 p.m. on the day before the operating day the ISO has a complete picture of the schedules making up the Day-Ahead Market.

5. In the afternoon between 1:00 and 4:00 p.m., the ISO examines the units scheduled in the Day-Ahead Market and compares them to the reliability needs in the nine RMR areas in the state. Because many RMR Units are older and less efficient, it is often the case that much of the reliability need is not satisfied in the Day-Ahead Market. This means that dispatch instructions are issued in the afternoon between 4:00 and 6:00 p.m. to RMR units not cleared in

the Day-Ahead Market or scheduled as bilaterals. These dispatch instructions require them to generate specified amounts of Energy during specified hours of the next day. Creating dispatch instructions after Day-Ahead Markets clear results in incorrect clearing prices in the PX markets and marginal suppliers and producers seeing different prices. This economic problem is discussed in the report prepared by Mr. Hildebrandt. My purpose is to describe the operational problems that this causes. When RMR Units dispatched after the Day-Ahead Market actually produce power to support the reliability of the ISO Controlled Grid, as they must according to their contracts, the system has excess Energy, which creates an Overgeneration condition. This is because RMR Units that are instructed to generate do not have any demand or Load associated with their output. Because the instruction took place <u>after</u> markets were cleared, all such Generation will be excess in relation to scheduled Load.

6. Some entities serving Load, knowing that there will be excess generation in real time, purposely do not schedule in forward markets in order to absorb this excess. However, since Load does not know reliability requirements and since it cannot predict Generator bidding behavior, which determines which Generation clears the forward markets, Load does a very poor job of "showing up" in real time at the right quantities and in the right hours. This causes significant operating and market problems which I will describe. These problems include:

a. Excessive use of Imbalance Energy.

b. Excessive use of Regulation.

c. High volatility in imbalance prices.

d. Excessive "thinness" in imbalance markets.

e. Control problems and Reliability Criteria violations.

7. Excessive Use of Imbalance Energy. With significantly varying amounts of "excess" RMR Energy showing up in real time, the ISO's inventory of Imbalance Energy resources (often referred to as the "Imbalance Energy stack") is strained. Not only must the ISO call upon these resources to make up for normal variances in Load estimates, weather changes, etc., but it is forced to use them to absorb significant Overgeneration. It is not unusual to exhaust "decremental" bids (that is, offers by Generators to reduce their output) in attempting to absorb the excess.

8. Excessive Use of Regulation. As decremental bids are exercised in large quantities to absorb excess RMR Energy, through many Generating Units moving at different ramp rates at different times, regulating units are placed under significant strain to hold frequency within tolerance. This has been a major contributor to the ISO's need to purchase more Regulation (as a percentage of Load) than was required historically (6 - 12 percent, as opposed to 1.5 – 3 percent). This of course strains the Regulation market, causing high and volatile prices.

9. High Volatility in Imbalance Prices. As many imbalance bids are used, movement in the Imbalance Energy stack is large and varies significantly from hour to hour. This causes large price swings and significantly affects Generator bidding behavior. Load also attempts to respond, further increasing volatility and creating a "see-saw" effect.

10. <u>Excessive "Thinness" in Imbalance Markets.</u> As noted above, heavy use of Imbalance Energy resources, especially in a decremental direction, often exhausts the Imbalance Energy stack and makes price swings bigger as you get near the end of supply curves. This makes the ISO market less stable, creating the need to go "out-of-market" to make transactions necessary to balance the system.

11. <u>Control Problems and Reliability Criteria Violations</u>. The bottom line is that these large movements in real time operations create difficulty in controlling the system, which increases the likelihood and occurrence of Reliability Criteria violations and path overloads. The Western Systems Coordinating Council's CPS2 standard requires that imbalances in Generation and Load be mitigated in 10 minutes or less. The large movements in Imbalance Energy resources that are required to accommodate excess RMR Energy showing up in real time create situations in which it is difficult to avoid violations of this standard. Path overloads occur when large imbalance requirements, combined with large and fast Regulation responses, cause Intra-Zonal Congestion or Inter-Zonal Congestion in portions of the grid. Such Congestion further exacerbates the imbalance problems noted above by placing additional requirements on the Imbalance Energy stack, which is already strained.

12. The important point here is that none of these undesired effects are necessary. If RMR Energy, which must run, were matched against Load in one of the forward markets, then there would be no additional imbalance need, no strain on Regulation, less volatility in imbalance pricing, less strain on supply and better system performance for reliability.

13. Therefore, wholly apart from all the economic arguments, when there is a "must run" situation for the resource, Load must be scheduled against the Energy that resource produces. This can best be accomplished by making reliability requirements known before the Day-Ahead Markets and then requiring all Generators to be scheduled against Load in the Day-Ahead Market or, at least, in the Hour-Ahead Market.

14. Their process presents no economic consequence to the Generators, since they can choose to be paid under their respective RMR Contracts at "cost based" rates, or alternatively to accept market prices as payment. In either case they must be scheduled against Load as either a PX schedule or a bilateral transaction, in order to ensure that the real time effects I have described are avoided.

15. The ISO's proposal accomplishes this by requiring Generators who elect to get paid cost-based rates that day to bid zero in the PX to assure they clear the market, meaning that their resources' Energy is matched against Load scheduled in the market. Alternatively, they may schedule a bilateral transaction in the Day-Ahead Market. Generators who elect market revenue may bid as they choose in Day-Ahead Market or do bilateral deals, but if they do not schedule in the Day-Ahead Market, they must bid zero in the Hour-Ahead to ensure that they will clear that market. Hour-Ahead bilateral deals are also allowed to satisfy the requirement. The point is that the Energy must be scheduled no later than the Hour-Ahead Market in order to get both correct economics and avoid the operational problems I have outlined. It is also important to note that bidding zero in any PX market does not mean that the

Generator will get paid zero. It simply ensures that the bidder will receive the Market Clearing Price and more importantly that it <u>will be scheduled</u>.

16. It has been suggested that scheduling the RMR Energy in the Day-Ahead or Hour-Ahead Markets will somehow create situations in which there is more Energy bid into the PX than there is Load, which will make the PX price zero. Requiring RMR Energy to be scheduled against the Load it serves will not cause this problem. Excess Energy in minimum hours and spring runoff situations have caused low or zero clearing prices in the PX in some spring months. RMR needs are low to non-existent in such off peak conditions and therefore will not create this theoretical problem.

17. In considering the operational problems caused by the the current approach to RMR scheduling and dispatch, it is useful to review the initial California market design and subsequent modifications. In the March 1997 initial Tariff filing, when the California investor-owned utilities ("IOUs") owned the Generation that was expected to be designated as RMR, there were two portfolios which were to be bid into the PX at zero as "must take" Energy. The first was the Regulatory Must-Take/Regulatory Must-Run Generation, consisting of nuclear units and QF Generators, as well as Hydro Spill Generation. The second was RMR Generation. Both of these portfolios were supposed to be submitted to the PX before its market ran for the first time at 0700. To accomplish this, it was envisioned that the ISO would identify RMR needs prior to the PX markets. In other words, the initial market design envisioned that RMR Generation would be reflected in the PX Day-Ahead Market schedules.

18. Between March 1997 and August 1997, as the IOUs' divestiture of Generating Units proceeded, this approach was changed to further the philosophy that the market should provide as much of the RMR need as possible. Under the revised scheduling approach, the RMR need would not be provided until after the initial PX schedules were submitted and after Congestion Management was run, but before the revised PX schedules were submitted. This timing was premised on the belief that the market should provide the Energy needed to support reliable operation of the grid, to the extent it could. Also, since Congestion Management in the Day-Ahead Market would deal only with Inter-Zonal Congestion (plans to address Intra-Zonal Congestion in forward markets were deferred), it was felt that RMR Units would not be able to exercise locational market power in the RMR areas, which are small and do not extend between Zones. In addition, issuing calls for RMR output between the preferred and final Day-Ahead Schedules would still provide the opportunity to schedule all RMR Units against load in the final PX Day-Ahead schedules, thus avoiding the problems I have discussed.

19. During the Operational Dry Run ("ODR") period between October 1997 and March 1998 it became apparent that comparing the RMR needs to the Energy reflected in the preferred PX Day-Ahead schedules in each of the nine RMR areas to determine incremental needs for RMR Energy was time consuming, requiring 3-5 hours. The ISO, however, would have only 30 minutes after Congestion was run before Suggested Adjusted Schedules were given to the market at 11:00, allowing insufficient time for this process. Since start-up, RMR needs have been determined after the market is final, between 1:00 and

4:00 in the afternoon on the day before the operating day. While the process has been refined and somewhat automated, the determination of incremental RMR needs after the Day-Ahead schedules is still an intensive process consuming 1-2 hours. The notification and dispatch of RMR needs after the Day-Ahead Market gives rise to all the operational problems described above.

20. In addition, the PX, which represents 80-90% of the market, has not implemented the ability to participate in the iteration between 11:00 and 12:00, after Congestion Management. Therefore, Generating Units scheduling through the PX are not able to accommodate revised schedules in any meaningful way. Even if there were sufficient time to notify and dispatch RMR Generation before revised PX Day-Ahead schedules were submitted, the RMR Energy could not be reflected in those revised schedules.

21. A year and a half of operations is now behind us. It is now clear that from both the economic perspective and the operational perspective it is essential to move the RMR notification ahead of all the markets. The RMR Contracts have materially changed to correct flaws in the initial design and the reliability and operational problems associated with the current RMR notification and dispatch schedule have also been amply manifest.

22. As proposed by the ISO, notification and dispatch of RMR before the market will satisfy both the economic and operational needs demonstrated by the actual operational experience. In addition it will support the “market-first” change that originally caused us to move the RMR dispatch from pre-PX market to post-PX market timelines. Upon notification, which happens at 6:00 a.m., before PX markets, RMR Generators can now choose payment under the

contract or through the market (either a PX market or a bilateral transaction). The availability of the latter option ensures that the ISO will continue to obtain RMR Energy through the markets, where the market price is sufficient to attract that Energy. RMR Generators will elect to receive cost-based payments under their RMR Contracts when they estimate the revenues they would receive through market transactions to be less than their costs. If they expect market revenues to be greater than the cost-based contract payments, they will elect the market option. In that event, they receive payment for their Energy through the markets, <u>not</u> from the ISO, and they forego recourse to the contract. This allows the markets to provide and pay for all RMR Energy that they can provide.

23. Regardless of which payment option is selected, all Energy supplied by the RMR Generators is scheduled against Load in forward markets either as bilateral transactions or in PX markets. This avoids all the operational problems I explained earlier and provides clear and transparent signals to the markets.

I declare under penalty of perjury that the foregoing is true and correct. Executed on January 19, 2000.

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