EMPIRICAL ANALYSIS OF THE EXERCISE OF MARKET POWER IN CALIFORNIA ELECTRICITY MARKETS

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International Industrial Organization Conference
Industrial Organization Society
Atlanta, Georgia

April 9, 2005

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March 22, 2005

Beginning in June of 2000, spot wholesale electricity prices in California and other Western states rose to previously unprecedented levels. Understanding the causes of the crisis continues to have policy implications, particularly since some analyses have suggested that the price increases can be attributed largely to the exercise of market power. An alternative view is that many factors contributed to higher prices in California during 2000 and 2001, and the possible exercise of market power was, at most, only part of the explanation. It is important that these assertions that the price increases can be largely attributed to the exercise of market power be carefully investigated. The present paper summarizes empirical sensitivity analyses of the most prominent studies that have identified market power as a cause of a significant portion of the increase in Western prices. The work summarized here suggests that the data that have been used to conclude that the market power accounted for most of these price increases actually suggests that market power was unlikely to be the dominant factor and may not even have been a significant cause of the price increases. This finding does not prove that market power was not exercised but, rather indicates that the errors in these market power analyses have been larger

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than the effects being estimated. This is important because mistakenly attributing the bad outcomes in the west to the exercise of market power distracts attention from identification of the root causes of the crisis and leads in inappropriate policy conclusions.

I. INTRODUCTION

Beginning in June of 2000, spot wholesale electricity prices rose in California to previously unprecedented and unexpected levels. Even more surprisingly, spot prices continued to spike to high levels throughout the summer. Spot prices declined in the fall, then rose again and remained high through the spring of 2001, even during periods in which electricity demand was not normally high. The full story of the causes and consequences of these events is still unresolved although the events are now in the past and spot prices have fallen dramatically. It is still important to understand the causes of this complex matter because the causes continue to have policy implications. In particular, there have been a number of assertions that the rise in prices was mostly attributable to the exercise of market power.

A systematic exercise of market power could reduce or eliminate the consumer benefits of restructuring electricity generation markets. It is therefore important to identify circumstances in which market power is being or has been exercised, to understand the factors underlying the ability of market participants to exercise market power, and to address the policy implications. However, high wholesale electricity prices could arise from conditions of high cost and shortages, as well as from the exercise of market power. Moreover, since many of the remedies for high prices arising from the exercise of market power (e.g., divestiture and mitigation) are quite different from the remedies for high prices arising from high costs or capacity shortage (e.g., more investment in low cost electric generating capacity), it is important to distinguish among the various causes of high prices. Confusing an exercise of market power with other causes of high prices could lead to inappropriate policy responses that aggravate rather than remedy the real problem, or at least divert attention from critical issues. Indeed, just such a series of misdiagnoses may have played an important role in exacerbating the western energy supply crisis in 2000-2001.

It is therefore important from a public policy perspective to be able to distinguish empirically between high prices attributable to the exercise of market power or high prices attributable to high costs and high demand. One methodology that has been used in a number of papers to assess whether spot electricity prices have been affected by the exercise of market power is to simulate the competitive level of prices and then to compare the simulated prices with actual spot prices. Although appealing in principle, this indirect simulation approach imposes substantial burdens on the simulation model to distinguish the effect of an exercise of market power from higher costs, increased demand, capacity constraints, as well as from the lower costs intrinsic to simulated optimization versus imperfect real-world performance.

Such comparisons between actual and simulated costs are particularly problematic in the electric industry. The usual argument for why market power presents a special problem in the case of electricity emphasizes the tendency of the supply curve to rise rapidly at high levels of output near the capacity of the system. In this range, a small level of supply withholding to exercise market power could produce a large price increase. Unfortunately, this same feature means that small errors in the simulation model or small differences between theoretical and real-world system and generator performance could produce large changes in the simulated price in this same range. This analytical problem inherent in simulation models is compounded when the traditional tools for analyzing electricity markets are replaced by more approximate models that do not include factors that can materially influence the cost of meeting load in actual operations, e.g., the need for operating reserves, start-up and minimum load costs of operating units, transmission congestion, generation ramping constraints, uncertain load, unit operating inflexibilities, environmental restrictions, and uncertain outages.[2]

Over many years, the standard industry simulation models (e.g., GE-MAPS, ProMod or Gridview (ABB)) evolved to incorporate such features, driven by a recognition that these features of the real electricity system can have a material effect on the costs of operations. Including the additional detail makes the simulation exercise more difficult, but it has been accepted in the industry that the benefits of improved realism were worth the costs. The exception has been in the recent empirical studies of the exercise of market power in electricity

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2 Scott M. Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000 (hereafter Harvey-Hogan October 2000); Scott M. Harvey and William W. Hogan, "On the Exercise of Market Power Through Strategic Withholding in California," April 24, 2001 (hereafter Harvey-Hogan April 2001); Scott M. Harvey and William W. Hogan, "Identifying the Exercise of Market Power in California," December 28, 2001 (hereafter Harvey-Hogan December 2001); and Rajesh Rajaraman and Fernando Alvarado, "[Dis]proving Market Power," January 24, 2002 (revised March 2, 2002).

markets. The most prominent analyses that have found a ubiquitous exercise of market power in electricity markets have been based on simplified models which largely ignore these details, rather than using standard industry simulation models. This practice simplifies the simulation but further increases the likelihood that it is the approximations that lead to differences between observed and simulated prices.

In addition to simulating the competitive price, therefore, it is equally important to identify the sensitivity of that estimate to changes in assumption that might reflect errors in the model. If the sensitivity analysis reveals relatively small changes in the simulated price, the errors may not be important. But if the sensitivity analysis produces a wide range of prices, a range large enough to include the observed prices, then the simplified model may not be able to distinguish between the exercise of market power or the errors in the simulation model. There has been, nevertheless, a continuing series of studies that report finding pervasive exercise of market power in wholesale electricity markets based on comparisons of actual and simulated prices in California,[3] PJM,[4] and New England.[5] All of these studies have used highly simplified market models and have included little or no sensitivity analysis of key assumptions. This paper

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3 Severin Borenstein, James Bushnell, and Frank Wolak, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market," August 2000 (hereafter BB&W 2000); Frank Wolak, R. Nordhuas and Carl Shapiro, "An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets," September 2000; Paul Joskow and Edward Kahn, "A Quantitative Analysis of Pricing behavior in California's Wholesale Electricity Market During Summer 2000," March 2001 (hereafter Joskow-Kahn March 2001); Paul Joskow and Edward Kahn, "Identifying the Exercise of Market Power: Refining the Estimates," July 5, 2001 (hereafter Joskow-Kahn July 2001); Paul Joskow and Edward Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000: the Final Word," February 4, 2002 (hereafter Joskow-Kahn February 2002); Severin Borenstein, James Bushnell and Frank Wolak, "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market," June 2002.

4 E. T. Mansur, "Environmental Regulation in Oligopoly Markets: A Study of Electricity Restructuring," November 2001; Erin Mansur, "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market," April 2001; Erin Mansur, "Vertical Integration in Restructured Electricity Markets: Measuring Market Efficiency and Firm Conduct," October 2003. PJM covers a region in the Mid-Atlantic states. For an exception, see the sensitivity analysis in Erin T. Mansur, "Measuring Welfare in Restructured Electricity Markets," Yale University, September 3, 2004, which argues that simplified simulation overstates the welfare loss after accounting for unit commitment effects.

5 James Bushnell and Celeste Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," February 2002 (hereafter Bushnell and Saravia). Bushnell and Saravia find an average price markup that exceeds the threshold proposed by the California ISO as a trigger for automatic implementation of market power mitigation; California ISO MD02 proposal submitted to FERC, May 1, 2002.

focuses on two studies of the California electricity market that have recently been published in *The Energy Journal*(Joskow-Kahn)[6] and *The American Economic Review* (BB&W).[7]

The present paper reports on a sensitivity study both of the Joskow-Kahn simulation analysis (which relies solely on publicly available data) and a sensitivity study based on additional confidential data more akin to the BB&W study. The sensitivity analysis could be extended to utilize the standard industry simulation models, but this would require additional data affecting both the unit commitment and dispatch conditions. Given the limitations of the simplified simulation models, the purpose of the present paper is not to produce a better estimate of the competitive price levels. Rather, the focus is more on assessing the degree of confidence that one can place on the estimates produced by these kinds of models, the importance of some of the common simplifications in these models, and whether these models provide a sound basis for drawing strong conclusions regarding the cause of high prices in California. As a first step, an attempt to independently replicate the simulated prices was not fully successful and this itself illustrates the difficulty of building a reliable simulation model. Then with this baseline, various tests assess the impact of some of the simplifying assumptions in the Joskow-Kahn and BBW simulations.

The results produce a wide range of simulated prices, a range that includes observed market prices. This indicates that the sensitivity analysis of simulation results is essential in assessing any policy conclusions. Drawing inferences regarding competition based on comparisons between actual prices and those simulated in these simple models could produce substantial errors. The difference between the actual and simulated prices could arise from the real-world constraints omitted from the model in conjunction with purely competitive behavior, or the difference could arise from the exercise of market power by sellers that are able to raise prices because of constraints omitted from the model. One simply cannot tell from these simulations. While the potential exercise of market power in deregulated wholesale electricity markets is an important concern that deserves careful scrutiny, the methodology employed in

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[6] Paul Joskow and Edward Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Market During Summer 2000," *The Energy Journal*, September 2002, p. I-35 (hereafter Joskow-Kahn 2002).

[7] Severin Borenstein, James Bushnell and Frank Wolak, "Measuring Market Inefficiencies in California's Restructured Electricity Market," *The American Economic Review*, December 2002 (hereafter BB&W 2002).

these simulation studies appears likely to find that market power has been exercised regardless of the competitiveness of the market.

A more direct approach to the identification of the exercise market power would be to assess whether capacity has been strategically withheld from the market during high priced hours. Given observed market prices, estimated production capacities and costs, and actual production for individual plants over a period of time, a significant exercise of market power would reveal repeated deviations from competitive profit maximizing production levels, that are unambiguously outside the range of potential cost variations. Typically the deviations would appear as offering less than the competitive level of output taking account of prices, environmental restrictions, ramp rates, deratings, and supply of ancillary services.

Analyses by Paul Joskow, Edward Kahn and Robert Reynolds have attempted to assess the role of market power in elevating California electricity prices by examining actual output data and both conclude that there is evidence of strategic withholding. These analyses, however, do not take account of environmental output limits, generating unit operating constraints, real-time operating problems, system operator dispatch instructions or settlement rules, and imperfectly measured costs. In revisiting these analyses, we find that the Joskow-Kahn study provides no evidence of withholding, while a review of Dr. Reynolds more detailed analysis for one company (Mirant), shows that economic withholding by Mirant could not have been material.

Finally, the BB&W, Joskow-Kahn and Reynolds analyses all discuss physical withholding of capacity but provide no evidence that physical withholding of capacity actually occurred. Review of the overall on-line availability of non-utility generation (NUG) finds that much more generation was on-line during the crisis period than under utility operation. In addition, detailed outage data for generating plants owned by Mirant have been made available, allowing for analysis of outage rates for a significant group of plants in the California market. A detailed analysis of the outage rates of Mirant generation, controlling for production time since the last forced or maintenance outage, finds that outage rates were materially lower, not higher, during the crisis period than they had been under utility operation.

In every case addressed, the evidence for an exercise of market power has not withstood the sensitivity analysis. The conclusion of the analysis in this paper, however, is not that it is impossible to reliably detect the exercise of market power in the electric industry. The exercise of market power can be identified through examination of economic and physical withholding and most of the limitations of the Joskow-Kahn and Reynolds withholding analyses are avoidable as the information required to address these limitations should be readily available to the system operator. Furthermore, while there may be some unavoidable ambiguity in the availability of capacity impacted by outages or deratings on a particular day, it should be possible to identify systematic patterns of physical withholding of capacity through outages or deratings during high priced periods.

II. SIMULATING COMPETITIVE PRICES

A. Simulation Methodology

There is a long history of building and using dynamic multi-price models to analyze a wide array of energy policy problems in the electricity industry. Experience with even very complex simulation models (e.g., GE-MAPS and Promod IV), which include network constraints, ramping rates, and many other characteristics within an optimization framework to replicate the chronological decisions of economic dispatch, indicate that the optimized output in the model invariably fails to reflect important constraints facing real system operators.[8] Even with a good, or very good model, differences between simulated and real results arise because of simplifications in the model. In the typical application, the impact of simplifications in the model is addressed by comparing results between different simulation cases, thereby attempting to isolate the effects of the differences in the simulation cases and net out any bias in the simulation models.

With the focus on market power problems, however, there has been a new approach to simulating the operations of the electricity system, using models that strip away most of the details of the electricity system. In particular, the new approach has been to ignore all the

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[8] In part because of MAPS and Promod's origins as single control area planning models, there are several features of multi-control area operation that are highly approximate and the models do not account for the occasional turmoil and uncertainty of real-time operation.

complications of the electric network to assume that the market operates effectively at a single location. Further, these models ignore dynamics and assume that each electricity plant has complete flexibility to change its output in any hour based on the economics of price versus a variable cost in that hour, with no start up costs, minimum load costs, ramping constraints or minimum run or down times. With these simplifications, the resulting model views each hour as independent of all other hours of operation. Hence, there are no dynamic effects. The model is static and solved separately for each hour. Furthermore, without separate treatment of different locations or products, the market outcome reduces to a single market price for energy. Hence, the resulting model is a static single-price simulation.

With these assumptions, the static single-price simulation requires data on plant capacities, incremental energy costs, and aggregate demand for energy and ancillary services. Given a rule for simulating outages and deratings either by randomly selecting available plants in each hour, or by derating the output of all plants using an average availability factor, the energy bids of the available plants are stacked from lowest to highest. Starting from the bottom with the cheapest, plants are dispatched until the combined output meets the aggregate load. The incremental cost of the most expensive plant dispatched determines the simulated competitive price. This analysis is repeated separately for each hour and this simulated price provides the competitive standard for comparison.

The validity of using a static single-price simulation rests on the premise that the errors induced by the simplifications are not significant compared to the price markups reflecting a difference between simulated competitive prices and the observed market prices. Given the long history in the electric industry of use of dynamic multi-price simulation models, applied with care and caution, this is a somewhat surprising assumption. Were it true, the widespread industry practice over many years of investing in the more complicated models would not have been rational. Furthermore, the switch from the traditional methodology of comparing simulation cases (which tend to net out the modeling bias) to direct comparison of a simulation case with the real data, should raise a further caution about the reliability of the new methodology. The purpose here is to assess the assertion that the static single-price simulation model does not introduce errors as large or larger than the effect it is intended to estimate.

Although studies have been undertaken of NEPOOL and PJM electricity markets as well of California, the sensitivity analysis discussed here was undertaken for the California studies, in part because of familiarity with a number of the data sources and because market prices reached much higher and more controversial levels in California. The initial focus is on the simulation results from Joskow and Kahn because they based their work on public information. Additional sensitivity cases based in part on the confidential data that was utilized in the BB&W studies are then reported.

The starting point for the sensitivity analysis is replication of the most recent Joskow and Kahn simulations, which use only publicly available data. The replication focuses on June 2000 because of the large gap they found between actual and simulated prices during that month.[9] The Joskow-Kahn methodology has not been fully described, however, and there are many important steps in the simulation for which their papers provide little guidance, in particular the derivation of the actual output of geothermal, cogeneration, and solar and bio-mass generating units used in the model. In filling in these gaps it was attempted to utilize the data sources referred to by Joskow and Kahn, and to be conservative (choosing the alternative that would tend to result in lower simulated prices).[10] The base-case replication of the Joskow-Kahn simulation for June 2000 derived an average monthly electricity price of $85.28 per MWh at a $10/pound NOx cost with real-time imports calibrated against day-ahead prices, which is noticeably higher than the $67.23 figure reported in Joskow-Kahn September 2002.[11] The methodology employed in Joskow-Kahn September 2002 apparently scheduled imports to clear the market, regardless of whether the resulting simulated price was above the prevailing Cal ISO price cap.[12] This

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9 This analysis of a single month does not demonstrate that the prices prevailing in the WSCC during 2000 and 2001 can in all cases be explained by purely structural considerations. The purpose of the analysis is to demonstrate that the simplifications commonly made in simulating electricity prices with single-stack models introduce such a wide range of error in simulating market prices that the error is larger than the effect being estimated.

10 The details of the replication methodology are described in Scott M. Harvey and William W. Hogan, "Market Power and Market Simulations," July 16, 2002 (hereafter Harvey-Hogan July 2002). The replication uses the same $4.59/mmBtu North and $4.99/mmBtu South gas prices as Joskow and Kahn, and also utilizes the same $10/lb. SCAQMD NOx allowance costs.

11 BB&W appear to have used a much lower NOx allowance cost, using an average of market prices and zero priced affiliate transfers.

12 Joskow-Kahn 2002, p. 13, states "We rely upon imports to clear the market when in-state fossil supply is exhausted. Because this will occasionally require more net imports than what was actually observed, our procedure will raise their price substantially when this is required. These prices will be higher than the ISO

approach has the potential to lead to extremely high hourly prices during shortage hours that might materially impact the simulated monthly average prices, hindering meaningful comparisons with actual Cal ISO spot prices, which were subject to a price cap. For this paper the monthly average prices have been calculated, both with and without a $750 cap on the simulated prices. With the $750 price cap applied to the simulation results, the average June price in the base case simulation falls to $76.90. Actual prices ranged from $111.48 (the average of the lowest INC price on SP-15 in each hour)[13] to $131.55 (the NP-15 hourly real-time price).

The base case simulation model was also run calibrating real-time imports against real-time prices (instead of day-ahead prices) and these results are also portrayed in Table 1. Joskow and Kahn scaled actual real-time imports up or down based on the relationship between the simulated price and *day*-ahead price rather than adjusting the simulated level of real-time imports based on the relationship between the simulated price and the actual real-time price. The simulated prices are about $6/MWh higher than if real-time imports are calibrated against real-time prices rather than day-ahead prices. In examining the simulation results, it appears that calibrating real-time imports against day-ahead prices as Joskow and Kahn did in their paper tends to depress simulated prices relative to real-time on the days on which real-time prices greatly exceeded day-ahead prices, because more imports are assumed to be available at a lower price than was actually the case on such a tight supply day. Conversely, on days on which real-time prices were much lower than day-ahead prices, calibrating real-time imports against day-ahead prices tends to reduce simulated import supply but this appears to have little impact on simulated prices because demand is low.[14]

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price caps in place during the summer. We interpret these cases as corresponding to the ISO's purchase of Out of Market (OOM) energy."

13 Comparisons based on the lowest INC price isolate the extent to which the hourly price is due to sustained conditions as opposed to intra-hour ramping constraints and load peaks that are not included in an hourly simulation model.

14 BB&W also appear to have calibrated real-time imports against day-ahead prices.

Table 1
June 2000 Prices

	ISO	SP-15	NP-15
PX Prices Actual		116.85	125.73
PX Prices Unconstrained	120.20		
ISO-Real-Time-Hourly		121.95	131.55
ISO-Real-Time-Lowest INC[1]		111.48	117.30
BB&W (2002)	53.59		
Joskow-Kahn (uncapped)			
March 2001	62.60		
July 2001 10-Load Slices	53.98		
July 2001 100-Load Slices	74.03		
September 2002 100-Load Slices	67.23		
Joskow-Kahn Replication 720 Load Slices			
Uncapped Prices			
Imports – PX Price	85.28		
Imports – Real-Time Price	91.97		
Capped Prices			
Imports – PX Price	76.90		
Imports – Real-Time Price	82.63		

[1] Lowest 10-minute interval price in hour.

The noticeable differences between the base case simulation results and those reported by Joskow-Kahn indicate that some of the various methodological ambiguities have been resolved in a manner different from that of Joskow-Kahn. These ambiguities, however, were resolved here in a reasonable and conservative manner and applied the spirit, if apparently not the letter, of the methodology described by Joskow and Kahn.[15] The apparent sensitivity of the simulated prices to seemingly innocuous differences in assumptions underlines the need for sensitivity analyses and replication. The several Joskow-Kahn implementations of the single-price simulation methodology produce a range of average prices from $54 to $74, suggesting the difficulties even when the methodology is well known.[16] Here the attempt at independent replication adds almost

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15 It will be seen below that our resolution of these ambiguities was also conservative relative to the real world, as prices simulated using actual hydro, geothermal, cogeneration, wind, solar and bio-mass output are higher than those we simulated based on approximate public data.

16 Among other uncertainties, it is not certain which utility and fringe generating units were included in these models. If the Joskow-Kahn or BB&W simulations treated mothballed utility or fringe generation as available

50 percent to the range of estimates. It is reasonable to infer that these results give a rough estimate of the error inherent even within the simplified framework of the single-price simulation methodology.

The second stage of the analysis was to use this replication to test the impact of alternative assumptions regarding reserve requirements, environmental constraints, start-up and minimum-load costs, outages, hydro power availability, and import elasticities. These start with the replication which serves as the basis of comparison. Hence, the sensitivity tests do not depend on the full resolution of the difficulties in repeating what Joskow and Kahn reported. This resulted in several hundred sensitivity cases; these results, as well as the model used to estimate them, are posted on the web.[17] It is seen that essentially every case that accounts for actual California Independent System Operator (Cal ISO) reserve requirements produces simulated prices that are consistent with or above average actual prices.

B. Sensitivity Analysis

There are several potentially important assumptions embodied in the Joskow-Kahn and BB&W simulation results. While the data required to assess the impact of some of these assumptions are not available, an important purpose of this paper is to assess the practical significance of those simplifying assumptions that it is possible to analyze, including operating reserve requirements, recognition of start-up and no-load costs, delta dispatch restrictions, outage status, inter-zonal congestion and non-NUG output as summarized in Table 2 (appended). A complicating factor in providing this sensitivity analysis is that it is anticipated that the effects of variations in assumptions will not necessarily be linear, hence one cannot simply compute a few cases and sum the effects to assess their cumulative impact. Computational complexity has been balanced with informational needs by calculating prices for all of the permutations and combinations of certain assumptions (hydro capacity, reserve requirements, environmental limits (e.g., delta dispatch), NUG outages and regulated unit output, and undertaking a more limited set of price

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for dispatch, that would have lowered prices but this would not reflect economic or physical withholding by non-utility generators.

[17] See www.lecg.com/Practice Areas/Energy/Research Papers and Testimony.

calculations for some of the other sensitivity assumptions. As noted above, all of the sensitivity analyses are based on an import supply curve calibrated against real-time prices.

Operating Reserves. The first of the sensitivity analyses examined concerns the level and method of accounting for operating reserves in the Joskow-Kahn simulations. Although the original Joskow-Kahn simulations assumed an overall Cal ISO ancillary services requirement of 10 percent of load for reserves and upward regulation and dispatched generation based on its offer prices to meet load plus 10 percent,[18] the simulations reported in later papers assumed an overall Cal ISO ancillary services requirement of only 3 percent (for upward regulation) and dispatched generation to meet load plus 3 percent.[19] As pointed out in an October 2000 paper, simulating market prices taking account only of a 3 percent ancillary services requirement is not consistent with the real-world operation of the transmission system operated by the Cal ISO, as the Cal ISO would almost certainly shed load before it would let its operating reserves go to zero and would, in practice, buy high-priced imports to maintain reserves. In fact, NERC and WSCC policies require the Cal ISO to buy high-priced imports to maintain reserve levels.[20]

BB&W also ignore operating reserve requirements in their simulation model, arguing that it is not necessary to take account of reserves on the basis that "with the exception of regulation

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18 Joskow-Kahn March 2001, p. 11.

19 Joskow-Kahn July 2001, pp. 7-8, and Joskow-Kahn February 2002, p. 13.

20 "Each Region, subregion or reserve sharing group shall specify, and each control area shall provide, as a minimum, operating reserve as follows: (1) Regulating Reserves. An amount of spinning reserve, responsive to AGC, which is sufficient to provide normal regulating margin, plus; (2) Contingency Reserve. An additional amount of operating reserve sufficient to reduce area control error to meet the Disturbance Control Standard following the most sever single contingency. (2.1) Spinning Reserve. At least 50% of this operating reserve shall be spinning reserve, which will automatically respond to frequency deviations." NERC Policy 1, p. P1-1 to P1-2.

"Each control area shall maintain minimum operating reserve which is the sum of the following: Regulating Reserve. Sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the control area to meet NERC's Control Performance Criteria. Contingency Reserve. An amount of spinning and nonspinning reserve, sufficient to meet the Disturbance Control Standard as defined in 1.E.2 (a). This Contingency Reserve shall be at least the greater of: (1) The loss of generation capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency (at least half of which must be spinning reserve); or (2) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation (at least half of which must be spinning reserve)." Western Systems Coordinating Council, Minimum Operating Reliability Criteria, p.2,

For a further discussion, see Harvey Hogan December 2001, pp. 36-40.

reserve, as described below, all other reserves are normally available to meet real-time energy needs if scheduled generation is not sufficient to supply market demand. Thus, the real-time energy price is still set by the interaction of real-time energy demand – including quantities supplied by reserve capacity – and all of the generators that can provide real time supply."[21] This view is mistaken. The California market design does permit units that are being paid as reserves to be dispatched to provide energy if their offer price is less than the market price, but this market rule only changes the identity of the units providing operating reserves,[22] it does not change the fact that NERC and WSCC reliability criteria require the Cal ISO to maintain operating reserves. The Cal ISO itself recently noted

> The ISO, as the Control Area Operator, is obligated by the Western Electricity Coordinating Council ("WECC") Minimum Operating Reliability Criteria ("MORC") to maintain a certain minimum level of operating reserves. At least fifty percent of this reserve must be synchronized to the grid and available within ten minutes. Due to the fact that the ISO Control Area is, with respect to total system load and control of generation, among the largest and most electrically influential in the Western Interconnection, careful maintenance of the reserve is essential to the integrity of the ISO Control Area and the Western Interconnection.[23]

If there is insufficient undispatched capacity within the Cal ISO control area to maintain the minimum level of reserves, the Cal ISO is required to buy energy from suppliers external to the Cal ISO control area and back down internal generation to maintain the MORC level of reserves. The market price set by this import supply could greatly exceed the price simulated in the BB&W and Joskow-Kahn simulation models.

If the Cal ISO was unable to maintain the MORC level of reserves it would declare a stage 1 emergency and begin taking other actions to restore reserves including the dispatch of interruptible load. If reserves fell to 1.5 percent the Cal ISO control area would be in a Stage 3

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[21] BB&W 2002, p. 1384.

[22] This feature of the California market design is problematic and likely contributed to the reliability problems encountered during 2000 and 2001. The highest valued use for dispatchable limited energy units would likely have been to provide reserves during this period. Because the Cal ISO includes reserves in the general dispatch stack these units could only avoid being dispatched to provide energy by offering energy at very high prices, but they were often prevented from doing so by various bid caps. This caused the limited energy units to be dispatched inefficiently, exhausting their energy supply and making them unavailable to provide reserves.

[23] California ISO, "Commentary by the California Independent System Operator Corporation on the CPUC Staff Investigative Report on Wholesale Electric Generation," released September 17, 2002," October 25, 2002, p. 6.

emergency and involuntary load shedding would be implemented, as was the case during 2001. After accounting for upward regulation, BB&W and Joskow and Kahn effectively model the Cal ISO as operating in a state of Stage 3 emergency during high load periods without taking any action to buy high cost power to maintain reserves. This mistake does not make much difference during low demand periods because reserve capacity would be available and the need to maintain reserves would not have raised prices.[24] During the summer of 2000, however, the Cal ISO was short of capacity and operated in Stage 1 and 3 emergency levels during all or part of 38 hours during June 2000. Failure to take account of operating reserve requirements transforms the actual shortage situation during these hours into a surplus. For this reason alone, the Joskow-Kahn and BB&W simulation results provide no guidance regarding the competitive level of prices in California during the summer of 2000.

On the other hand, dispatching generation to meet load plus 10 percent based on energy offer prices is likely to overstate energy prices during non-shortage conditions as the assumption in effect requires the Cal ISO to buy energy to meet its reserve requirements. Thus, while the assumption that there need only be enough capacity to meet a 3 percent ancillary services requirement is inappropriate, it is not possible to precisely replicate the impact of the Cal ISO's actual ancillary services requirements in idealized generation stacking models of the kind utilized by Joskow and Kahn, BB&W, Mansur or Borenstein and Saravia. Furthermore, reserve data at the level of detail needed for the simulation model have not been publicly available from the ISO. This paper assesses the sensitivity of these results of these price simulations to the modeling of reserves by examining the impact on the simulated price of several alternative rough representations of Cal ISO ancillary services requirements, none of which provides a fully accurate portrayal of actual ancillary service requirements but which roughly bound the appropriate price level. Two alternatives are: (1) R2: Energy is dispatched to meet Cal ISO real-time load increased by 10 percent to reflect ancillary service requirements; and (2). R5: Energy is dispatched to meet Cal ISO real-time load increased by 3 percent (to reflect impact of ramping constraints on the cost of energy dispatched to meet load), plus an available capacity

[24] During very low demand periods the need to maintain reserves tends to depress energy prices as additional generation must be committed uneconomically at minimum load in order to maintain reserves, depressing energy prices. This is likely one of the reasons that the BB&W type simulations overstate prices during low demand months.

requirement (including spinning and non-spinning reserve imports plus 500 MW of assumed unloaded hydro capacity) of load plus 10 percent.[25]

The R2 reserve case differs from the base reserve case in that supply is dispatched to meet 110 percent of load, rather than 103 percent. This is consistent with the assumptions used to proxy for Cal ISO ancillary services requirements in a variety of contexts, including the original Joskow-Kahn simulation, and probably roughly corresponds to the Cal ISO's actual demand for capacity. Significantly, this measure of demand correctly attributes high prices to true shortage under shortage conditions. On the other hand, as noted above this measure is likely to overstate energy prices during non-shortage conditions as it in effect requires the Cal ISO to buy energy to meet its reserve requirements. The impact of changing the ancillary service assumption to that utilized in the original Joskow-Kahn simulation, while holding the remainder of the methodology constant, is to raise the simulated price without a $750 price cap to $165.69 (well above the actual price). If a $750 price cap is applied to the hourly prices, the simulated price is $115.74 (slightly lower than the actual average hourly price).

The R5 reserve case attempts to correct for the potential of case R2 to overstate market prices in non-shortage situations by dispatching energy to meet 103 percent of load as in the base case. The 3 percent margin is taken to roughly reflect the impact of ramping constraints on the cost of the generation required to meet load. In addition the level of total capacity available at this price is calculated, and if the available capacity is less than 110 percent of load, the price of energy is raised until sufficient imports are drawn into the market to provide capacity equal to 110 percent of load. That is, energy imports are scheduled and units internal to the Cal ISO control area are backed down until reserves equal to 10 percent of load are created. In this calculation, capacity is defined as total must take energy plus all available dispatchable capacity, plus import supply at the market clearing price. The measure of available capacity also includes the hour-ahead schedules for spinning and non-spinning reserve imports and a further allowance for 500 MW of unloaded capacity on hydro units (in addition to imported reserves) to provide a sense of the impact of such capacity. This measure identifies hours of capacity shortage without overstating the energy cost of meeting load. It is not known whether the 3 percent assumption

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25 Additional intermediate cases (R3 and R4) are discussed in Harvey-Hogan July 2002.

accurately reflects the impact of real-world ramping constraints. In addition, the measure of available capacity is very approximate and may understate the available capacity. The simulated uncapped price falls to $138.77 in the R5 case, while the simulated price with a $750 hourly price cap is $100.94. The capped price is noticeably less than actual prices, but much closer to actual prices than to the prices simulated by Joskow and Kahn.

The need to take account of operating reserve requirements should not be controversial and this limitation of the original BB&W simulations was pointed out in October 2000, but none of the subsequent BB&W or Joskow-Kahn papers has even included a sensitivity case reflecting actual real-world operating reserve requirements. The system is in a shortage condition when there is not enough capacity to meet load and provide reserves and this needs to be recognized in a competitive market simulation.[26] Moreover, it is seen above that the results of these simulations are in fact very sensitive to the omission of operating reserve requirements.

Hydro Energy. A second sensitivity case considered is the level of hydro energy available on peak. Joskow-Kahn assumed in their later papers that 8,500 MW of hydro was available in the high-load hours and assumed that 8,000 MW were available in their original paper. The actual level of hydro energy that was available during the on-peak hours in June 2000 is not publicly available but the sensitivity analyses include a variety of possible levels to permit assessment of the impact of this assumption. The cases evaluated were: H1: 8,500 MW maximum; H2: 8,000 MW maximum; H3: 7,500 MW maximum ;H4 7,000 MW maximum;

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[26] The 2002 State of the Market Report, Midwest ISO, prepared by Potomac Economics Ltd., the independent market monitor for the Midwest ISO, noted in May 2003 at p. 51:

> Shortages arise when energy demand and ancillary service requirements cannot be simultaneously satisfied. Although these instances generally occur in only a limited number of hours per year, prices set during these hours are an essential component of the economic signals to:
> - Resources in other regions that could supply energy in response to the shortage;
> - Peaking generation whose primary value is to be available under these conditions; and
> - In the long term, existing and new generation needed to serve the region.

Further observing on p. 52 that:

> During shortage conditions when the energy demand is satisfied only by compromising the required operating reserves, the energy prices in the reserve deficient area should be set at the bid cap.

Indeed, the NYISO in 2003 filed changes to its market rules with FERC that were intended to ensure that real-time prices always reached the price cap when there was not sufficient capacity to maintain 10-minute reserves in real time. See NYISO, Docket ER03-766-000, April 23, 2003. On February 1, 2005 the NYISO implemented software that automatically elevates real-time prices (potentially by up to $1,600/MWh) when the NYISO is short of various categories of reserves within various regions.

H5: 7,000 MW at $0, 7001-7500 MW at $500; and H6: 9,000 MW maximum. Table 3 summarizes the impact of varying the assumptions regarding the amount of hydro energy available on-peak for the base reserve case and cases R2 and R5. In these simulations a 500 MW decrease in the amount of hydro energy assumed to be available in the peak hours tends to raise average monthly prices by about $5/MWh.

Table 3
Hydro And Reserve Cases
Capped Prices ($/MWh)

	R1	R2	R5
H6 (9,000 MW)	77.74	111.04	96.17
H1 (8,500 MW)	82.63	115.74	100.94
H2 (8,000 MW)	86.95	120.87	106.26
H3 (7,500 MW)	91.54	126.03	111.15
H4 (7,000 MW)	96.81	131.63	117.41
H5 (7,000 MW + 500 MW)	94.99	130.18	111.25

The assumptions regarding the level of hydro supply in high load hours therefore have an important impact on the simulation results, producing a range of $20/MWh in the simulated priced under most reserve model assumptions. It was observed in the July 2002 Harvey-Hogan paper that the single hydro supply case analyzed by Joskow-Kahn led to rather surprising price patterns in off-peak hours, suggesting that there was something amiss with their assumptions.[27] It will be seen in the discussion of actual hydro supply below, that the Joskow-Kahn simulation in fact substantially overstated the available hydro supply during peak hours.

Environmental. A third sensitivity factor was environmental restrictions. These are difficult to account for because not all of these restrictions are public. Moreover, some of the restrictions that are known (such as Mirant's Delta Dispatch restriction) had variable impacts that are difficult to model without access to extremely detailed operational data. The Delta Dispatch restrictions applied to eight of the Mirant generating units in the Bay Area during the period roughly from May to Mid-July. These restrictions were intended to prevent the discharge of

[27] See Harvey Hogan July 2002, pp. 41-42.

waste water from power plants from overheating the river and interfering with fish spawning during this period. During this period, the eight units were not permitted to operate at a level that would result in outlet water temperatures in excess of 86 degrees, except at the specific direction of the Cal ISO either to maintain local reliability or in emergency conditions. These restrictions resulted in large amounts of capacity being unavailable for dispatch to meet load outside the Bay area, except during emergency conditions.

The base case E1 is the Joskow-Kahn simulation which does not take account of any environmental restrictions. Case E2 proxies roughly for the impact of the Delta Dispatch restrictions on the Mirant Contra Costa and Pittsburgh units by reducing the capacity of the units subject to Delta Dispatch (Contra Costa 6-7, Pittsburgh 1-6) by 50 percent. This capacity figure likely overstates the available capacity on most days but may be too low at times. Given the variability of river conditions and tides, it is not apparent that there is any simple rule that would capture the reality of these limits. Case E2 potentially understates capacity on high load days because it does not account for the possibility that the Mirant capacity could sometimes be dispatched in non-emergency (i.e., non-shortage conditions) as a result of intra-zonal congestion (i.e., reliability must-run (RMR) dispatch) to meet Bay area load.

Case E3 attempts to account for the impact of both Delta Dispatch restrictions and RMR dispatch on the Mirant units by setting the output of the Mirant Delta Dispatch units equal to their actual CEMS output in that hour.[28] The Mirant Delta Dispatch units are therefore effectively treated during this period as price takers whose output was controlled by the Cal ISO's RMR desk, which is probably an accurate characterization.

Table 4 summarizes the impact of varying the assumptions regarding the impact of environmental restrictions across several reserve cases. Because of space limitations, results are reported only for the base case hydro assumption and capped prices.[29] It can be seen that the environmental assumptions have a material impact on the simulated capped prices, raising them by an average of $9 to $14/MWh even though account is taken of only one of the restrictions

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28 The raw hourly CEMS output is scaled down to reflect plant energy use using the June 2000 ratio of total net output reported to the EIA and total gross output reported in the CEMS data.

29 The average simulated uncapped prices for Case E3 and R2 or R5 consistently exceeded $200/MWh.

imposed on a single company (Mirant). This sensitivity case suggests the importance of accounting for environmental restrictions in price simulations. Other important environmental limits were the limits on annual operating hours that applied to somewhat more than 1,000 MW of the generating capacity included in the Joskow-Kahn simulation. Most of these limits restricted the hours of operation to 877 hours per year, while others were restricted to operating only 200 hours. A number of these units exhausted their hours of operation during both 2000 and 2001 despite offering their capacity at higher prices than assumed in the Joskow-Kahn simulation.[30]

Table 4
Environmental And Reserve Cases
Capped Prices ($/MWh)

	R1	R2	R5
E1	82.63	115.74	100.94
E2	90.48	129.33	111.00
E3	85.92	129.42	109.14
All simulations reported use base case hydro assumptions.			

Regulated Unit Output. Since the purpose of the simulation model is to separate the effects of shortage conditions from the exercise of market power by unregulated generators, the role of generation owned by regulated utilities deserves attention. As regulated entities and net buyers of electricity, the utilities would have an interest in lower, not higher prices. If anything, these generators would have an incentive to affect prices by producing too much, not too little output. It follows, therefore, that the observed actual output of the utility generation is an upper

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30 There are several complications in attempting to take account of these units in a simple simulation model such as that utilized by Joskow and Kahn. First, because the Joskow-Kahn model does not take account of transmission constraints it will not dispatch these energy-limited units as often as they actually operated in the real world as many of these units are located and used to solve transmission constraints. The model would therefore sometimes overstate prices because these units would not set prices when they were dispatched out of merit under RMR contracts to solve constraints. Second, the units are underdispatched in the Joskow-Kahn model at times when they would set prices because the Joskow-Kahn model does not take account of start-up costs, minimum load costs or minimum run times, making steam units appear lower cost than they actually are for meeting load peaks. Third, the units would also be underdispatched at times when they would set prices in the model because there are no demand or supply "surprises" in the Joskow-Kahn model, nor start-up times for steam units. In the real world, quick-start units are often dispatched to respond to unanticipated shocks in a timeframe in which off-line steam units cannot respond.

bound on their likely production at the observed prices in a competitive market. Simulated output in excess of the actual production for these suppliers would be evidence questioning the simulation model rather than evidence of an exercise of market power by the regulated suppliers.

Since the Joskow-Kahn simulation uses the theoretical capacity and estimated costs of utility generation to determine their output, actual prices could exceed the simulated prices because of the outages, offer prices and, operational performance of the utility generation rather than due to the exercise of market power by the non-utility generators. The extent to which the Joskow-Kahn simulation model may overstate the supply available from utility generation was assessed by capping the output of the utility steam generation in the model based on the hourly CEMS data. The output of gas turbines (GT) is not capped (because no CEMS data are available to measure their actual output) and their capacity is derated as in the base case per NERC EFOR ratings. This is case RUO2/N1.[31] The simulated prices are reported in Table 5 for several alternative sets of reserve and environmental assumptions. It can be seen that the difference between the predicted and actual output of the regulated units accounts for a $3-$7 increase in simulated prices across these cases. This indicates that the Joskow-Kahn model tends to overstate the competitive output of these suppliers and, presumably, similarly overstates the competitive output of the non-utility suppliers. The regulated units were dispatched for 405.83 GWh in the base case, while the NUGs were dispatched 3,847 GWh or more than nine times as much. If the dispatch of the NUGs is similarly overstated by the model relative to real-world operating constraints and costs, this could imply a further understatement of the competitive price level by $25-$60/MWh.

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[31] Since no CEMS data are available for Hunters Point Units 2 and 3, their output is not capped, but their capacity is derated as in the base case.

Table 5
Regulated Unit NUG Output Cases
Capped Prices ($/MWh)

Case	R1		R2		R5	
	E1	**E3**	**E1**	**E3**	**E1**	**E3**
Base	82.63	85.92	115.74	129.42	100.94	109.14
RUO2/N1	85.90	89.89	122.31	137.07	105.16	115.32
RUO2/N2	93.08	99.68	142.21	157.58	120.40	129.43
RUO2/N3	98.09	107.53	148.71	167.12	125.08	135.24
All simulations reported use base case hydro assumptions.						

Non-Utility Generation Outages. A further category of sensitivity analysis concerns the availability of non-utility generation. Joskow-Kahn model the impact of forced and maintenance outages by proportionately derating units, while BB&W use a Monte Carlo approach. Both the Joskow-Kahn and BB&W simulations are based on generic national average forced outage data, and on the assumption that maintenance outages can be scheduled such that a unit is never unavailable due to maintenance outages when needed to meet load. In addition, both simulations assume that steam units incur neither start-up nor minimum load costs and that there are no operating inflexibilities; that is, steam units can instantly come on-line when needed and go off-line as soon as they become uneconomic. None of these assumptions is warranted and the methodology is in general biased toward understating the competitive price level by overstating the capacity that would be available in a competitive market. There are four reasons for this.

First, in the actual operating world outages are often lumpy, so the impact of outages on the available capacity is less smooth than in the Joskow-Kahn simulation. The assumption that outages are proportionate therefore tends to increase the available capacity in shortage hours, and indeed less capacity would be needed and prices lower for any given level of capacity in such a world. BB&W do not take this smooth derating approach and instead utilize a Monte Carlo simulation methodology based on unit outage probabilities, which is more complex to implement but better reflects operating realities.

Second, neither the Joskow-Kahn nor BB&W methodology can distinguish between the possibility that actual prices are higher than simulated prices because actual outages and deratings exceeded those that would be predicted by the average NERC data versus the possibility that suppliers raised prices by exercising market power. The outage rates used in both studies are based on NERC data for generic units categorized only by type (steam, combined cycle, gas turbine) and unit size, rather than on the actual historical outage rates of the California units under utility operation. Moreover, both studies take account only of forced outage rates (i.e., outages that required on-line units to go off-line) assuming that all maintenance outages and overhauls can be scheduled during periods when the units would not be needed.

For the units of the one firm for which outage data are available, these assumptions are inconsistent with the actual historical operation of the units included in the simulation. Table 6 shows that the forced outage rates for the Mirant units under PG&E ownership and operation, while varying unit to unit, tended to greatly exceed the forced outage rates assumed in the Joskow and Kahn and BB&W simulations. This is particularly true for Pittsburg Units 1-4. Moreover, while the historical PG&E data show that forced and maintenance outage rates were lower in the summer months, consistent with PG&E trying to have as much capacity on-line as possible in the summer, Table 6 shows that the summer combined forced and maintenance outage rate under PG&E ownership tended to greatly exceed the forced outage rate used in the Joskow-Kahn and BB&W simulations. Thus, if similar differences exist for other units included in simulations, the Joskow-Kahn and BB&W simulations understate the competitive price level because they assume higher unit availabilities than were historically achieved by these units under utility ownership and operation.

Table 6
Actual and Assumed Outage Rates for PG&E/Mirant Units

	NERC/ Joskow-Kahn (A)	Annual Forced Outage 1994-1999 (B)	Annual Total Outage 1994-1999 (C)	Summer Forced Outage 1994-1999 (D)	Summer Total Outage 1994-1999 (E)
Contra Costa 6	8.51	23.75	31.51	6.73	16.75
Contra Costa 7	8.51	4.36	13.87	2.48	4.98
Average	8.51	14.05	22.69	4.61	10.86
Pittsburg 5	8.51	14.98	26.31	10.21	11.47
Pittsburg 6	8.51	2.05	12.76	0.58	21.22
Pittsburg 7	8.71	8.91	22.18	6.43	7.60
Average	8.58	8.65	20.42	5.74	13.43
Potrero 3	6.70	6.30	17.96	5.16	11.22
Pittsburg 1	10.30	50.48	56.64	49.07	52.50
Pittsburg 2	10.30	45.43	54.66	24.24	26.56
Pittsburg 3	10.30	68.55	76.03	42.21	45.39
Pittsburg 4	10.30	27.28	41.34	12.91	21.30
Average	10.30	47.94	57.17	32.10	36.44

(A) NERC GADS data, 1995 - 1999 Generating Unit Statistical Brochure, available at www.nerc.com/~filez/gar.html
(B) Forced outage hours January 1, 1994-December 31, 1998/ (forced outage + on-line hours)
(C) [Forced outage hours January 1, 1994-December 31, 1998/ (forced outage + on-line hours)] + [(maintenance hours/total hours)]
(D) Forced outage hours June 1 - September 30, 1994-1998/ (forced outage + on-line hours)
(E) [Forced outage hours June 1 - September 30, 1994-1998/ (forced outage + on-line hours)] + [(maintenance hours/total hours)]

Source: Table 78 p 178/179 Scott M. Harvey and William W. Hogan, Prepared Direct Testimony, FERC Docket EL00-95-075 March 3, 2003.

Third, the Joskow and Kahn and BB&W simulations both fail to take account of start-up and minimum load costs in developing a hypothetical "competitive supply" curve and thus overstate the output that would be available at a given price in a competitive market because the simulation model can meet load during individual simulation hours with the output of steam units that would not be economic to start-up or keep on line over night in the actual world.[32] Analysis of the dispatch pattern of generation in the replication of the Joskow-Kahn simulation

[32] This limitation was pointed out in Harvey-Hogan October 2000, pp. 38-39, Harvey-Hogan April 2001, pp. 25-33, and Harvey-Hogan December 2001, pp. 33-35.

and found that many units were dispatched to meet load in the base case simulation that could not have profitably operated if start-up and minimum-load costs were accounted for.[33]

Fourth, both simulation models also assume perfect foresight in a non-chronological model, i.e., the simulation assumes that steam units can be instantly started to meet load, and that demand is never misforecasted. Thus steam units are never off-line during high load conditions nor on-line during low load conditions. In practice, however, there was a substantial element of unpredictability to real-time prices during June 2000. The difference between day-ahead PX prices in NP-15 and the real-time imbalance price had a mean absolute value of $148, and a standard error of $236, while the figures were an absolute value of $136 in SP-15 and a standard error of $221. Modeling a world that had this degree of uncertainty as one in which suppliers had perfect foresight in scheduling their units on- and off-line is a non-trivial assumption. Moreover, this variation between day-ahead and real-time prices was not simply hour-to-hour variations that cancelled out over the day. The difference between the average on-peak (16-hour block) weekday NP-15 day-ahead PX and real-time ISO price for the same hours differed by $20/MWh of more on 19 of the 22 week days during June 2000. The similar statistic for SP-15 was 18 out of 22 weekdays.

On balance, these assumptions in the Joskow and Kahn and BB&W simulations tend to depress the level of simulated prices relative to the competitive price level. Two alternative cases have been analyzed to provide a rough assessment of the potential impact on the simulated price of these simplifications. One alternative approach was to use the actual on-line off-line status of non-utility steam units, per the CEMS data, to determine their availability. Thus, only units that were on-line in each hour in the actual world could be dispatched to meet load in this case.[34] This is case N2. This case, therefore, controls for the operating status of these generators, and prices will be higher in the simulation to the extent that steam units were off-line in the real-world due to outages, start-up costs, or misforecasted demand. This case cannot distinguish between

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33 See Harvey-Hogan July 2002, pp. 24-27, for a detailed discussion of uneconomic operation in the single-stack simulation model. It has also been shown that it would have been uneconomic in the real world for a number of these units to have been committed to operate during days with individual high priced hours; see Harvey Hogan April 2001, pp. 25-33 and Harvey Hogan December 2001, pp. 3-26.

34 CTs are assumed to be available in this simulation in every hour regardless of their on/off status in the real world because CTs and GTs are quick-start units that can come on-line in very short periods of time (10 to 30 minutes).

generators that were off-line because of outages, mistaken load forecasts, problems coming on line, as a result of physical withholding, or simply because prices were not high enough to warrant starting them. If steam units were in reality off-line as a result of physical withholding, this sensitivity case overstates the competitive price level.[35] Conversely, however, if these units were off-line in reality because of outages, unpredictable demand or because it was uneconomic to start them, then the Joskow-Kahn/BB&W simulation methodology understates the competitive price level.

Case N2 accounts for forced unit outages but makes no allowance for unit deratings. It therefore still has the potential to overstate the capacity actually available to the Cal ISO. Case N3 attempts to account for this possibility by excluding off-line units and derating on-line units to reflect NERC derating data.[36] Thus, steam units are on line if they were on line in real-time and are derated based on (EFOR-FOR)/(1-FOR) while, as in Cases N1 and N2, GTs are assumed to be available regardless of their on/off status per the EFOR rating.

Table 7 above reports the results of the N2 and N3 cases in conjunction with the RUO2 case for regulated unit output. It can be seen that taking account of the actual on off status of the NUG units has a material impact on simulated prices under either of the environmental assumptions and all of the cases which take account of actual Cal ISO reserve requirements, raising average monthly prices by \$20 to \$30/MWh. The simulated prices in these cases are generally consistent with actual prices, but noticeably higher than the actual price level in the 10 percent ancillary service requirement case (R2). It appears that this sensitivity case has a rather material impact on the simulated price level, suggesting that it is important that simulations take account of these considerations. As noted above, the high prices simulated could reflect the impact of the exercise of market power through physical withholding, but it needs to be shown that such physical withholding actually occurred in order to infer that market power was exercised.

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[35] It is seen below, however, that the actual availability of the Mirant units was considerably higher during the crisis period than it had been under utility ownership and operation.

[36] The use of NERC derating data provides only a rough approximation of the actual deratings. The NERC data controls only for fuel and capacity; it does not take account of unit age, type, current or past use, or past maintenance. Moreover, the derating data do not reflect all of the operational factors that limited real-world output such as air and water temperature, tidal conditions, clogged condensors, ramp limits, etc.

Transmission Congestion. One of the simplifications underlying the Joskow-Kahn and BB&W simulation models is that they do not take account of intra- or inter-zonal congestion. While there was generally not a great deal of inter-zonal congestion during June 2000, it was not entirely absent and could affect comparisons between actual and simulated prices. As a further sensitivity test, Table 8 reports the average simulated prices for the hours in which there was no inter-zonal congestion in the actual world. Comparisons between actual and simulated prices for these hours would control for the direct effects of the failure to model congestion in the simulation, although there would still be potential indirect dynamic effects between congested and uncongested hours. Actual real-time prices were slightly lower in these hours than in all hours, averaging $109.50 with an average lowest INC price of $94.11, which is again in the range of the prices simulated in the R2 and R5 reserve cases.

Table 8
Regulated Unit NUG Output Cases
Capped Prices: Real-World Uncongested Hours ($/MWh)

	R1		R2		R5	
Case	**E1**	**E3**	**E1**	**E3**	**E1**	**E3**
Base	74.15	76.96	101.83	114.67	89.69	97.11
RUO2/N1	76.69	80.10	107.01	121.21	92.55	101.86
RUO2/N2	83.07	89.33	125.70	140.50	106.15	114.81
RUO2/N3	87.44	96.54	131.47	149.33	110.19	119.93
All simulations reported use base case hydro assumptions.						

This sensitivity analysis does not take account of intra-zonal congestion, which could either raise or lower the market-clearing price in Cal ISO markets depending on whether the congestion required low-cost generation in a generation pocket to be backed down out-of-merit or high-cost generation in a load pocket to be dispatched up out-of-merit.

Import Elasticity. All of the sensitivity cases above have maintained Joskow-Kahn's assumed 0.33 elasticity for imports. This elasticity is an important assumption that lacks empirical support.[37] It is therefore useful to provide some assessment of the impact of alternative

[37] While the elasticity estimate assumed by Joskow and Kahn is loosely tied to results reported in BB&W 2000, (Joskow-Kahn March 2001, p. 12, Joskow-Kahn February 2002, p. 15) the BB&W methodology for estimating

assumptions regarding import elasticities. The price simulation was repeated with assumed import elasticities of 0.75 and 1.50. The impact of assuming a higher import elasticity is generally to raise the average simulated price, but for some of the high priced cases, the higher assumed import elasticity lowers the average simulated price. These mixed price impacts reflect the two countervailing effects of changes in import elasticities. On the one hand, a higher import elasticity means that an increase in internal California supply in the simulation relative to the real-world produces less of a decline in the market clearing price, while conversely reduced internal California supply relative to the actual world requires smaller price increases in order to attract sufficient imports to close the gap. Overall, the base case simulated price ranges from $82.63 at an elasticity of 0.33, to $91.78 at an elasticity of 0.75, to $99.22 at an elasticity of 1.50, so it is important in simulating prices to either base the analysis upon reliable estimates of this parameter or to allow for a range of values in sensitivity cases.

BB&W base the import supply curve used in their model in some manner on Cal ISO congestion adjustment bids but do not explain whether the supply curve is based on day-ahead or hour-ahead adjustment bids, how adjustment bids at different locations were combined, or whether imports are scaled based on the day-ahead or real-time price.[38] Moreover, since adjustment bids for congestion management in Cal ISO markets were price differences, it is not clear why these offers, particularly real-time offers, would be relevant to assessing the supply elasticity for imports or even how they were utilized.

Actual Hydro, QF, and Geothermal Output. It was possible to obtain access to actual hydro, QF and geothermal output data in a 2003 FERC proceeding and these confidential data were used to simulate market prices for June 2000 using the same simulation model described above. These results were subsequently made public by FERC. The simulation results based on the confidential data permit testing the sensitivity of the Joskow-Kahn simulation methodology to the assumptions used in estimating hydro, geothermal and QF output. In addition, the simulation results based on the confidential data should permit replication of the BB&W

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import supply curves is poorly described in all of the various BB&W papers and of uncertain validity (see Harvey-Hogan October 2000, pp. 35-36).

38 BB&W 2002, pp. 1387-88 and BB&W 2000, pp. 25-27. The methodological ambiguity has been pointed out in previous papers but BB&W have not elaborated on their methodology in their subsequent papers. See Harvey Hogan October 2000, pp. 35-36; April 2001, p. 21; December 2001, pp. 43-45; July 2002, p. 39.

simulation results, which were also based on confidential data. In addition, access to the confidential data allowed development of a much more accurate model of the impact of reserve requirements on market prices. These additional analyses are discussed below.

First, in comparing the data utilized in the July 16, 2002 study with the later confidential data, it was determined that the daily import data posted by the Cal ISO that were utilized in the July 16, 2002 simulation did not always include complete import data for all hours of the day. These differences were in general small. In addition, it was determined that a number of the units included in the posted Cal ISO lists of control area generation that were included and dispatched in the replication of the Joskow-Kahn simulation model, were not included in the confidential Cal ISO generation data and apparently injected no energy into the Cal ISO control area during June 2000.[39] Rerunning the base case simulation correcting for these data errors raised the simulated average capped price from $82.63/MWh to $85.47/MWh for June 2000.[40]

Second, an effort was made to replace the Joskow-Kahn assumptions regarding hydro generation and the sensitivity cases described above with the actual hourly hydro generation, based on confidential Cal ISO data. It was possible to identify the unit type for all but 17 units from various publicly available Cal ISO unit identification lists. Column A in Table 9 portrays the assumed hydro output of Cal ISO generation during June 2000 during the 10 load deciles used in the Joskow-Kahn analysis. Column B also portrays the average output during the hours of these load deciles of the units it was possible to definitely identify as hydro units. This data could understate hydro output to the extent that some of the 17 unclassified units are hydro generators. Column C portrays the output of the known hydro generation included in Column B and adds the output of all 17 of the unidentified units, which is the maximum possible level of hydro generation.

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39 The apparently erroneously included units were two LADWP units (Harbor units 6 and 7), six SMUD units (Campbell units 1 and 2, and Carson units 1, 2 and 3, and McClellan unit 1), and one Modesto Irrigation unit (Woodland).

40 The uncapped price was $98.89/MWh.

Table 9
June 2000 Summary Comparison of Hourly Hydroelectric Metered Generation by Joskow-Kahn Load Decile

Decile		Joskow-Kahn A	Total Known Hydro B	Total Known Hydro + Possible Hydro C
1	Average	3,484	2,962	3,667
2	Average	3,484	3,001	3,729
3	Average	3,484	3,243	4,027
4	Average	3,484	3,904	4,749
5	Average	3,484	4,466	5,355
6	Average	6,651	4,986	5,918
7	Average	8,500	5,050	5,945
8	Average	8,500	5,629	6,507
9	Average	8,500	6,022	6,877
10	Average	8,500	6,872	7,742

Notes:
1: Joskow-Kahn values exclude LADWP, Imperial and Pacificorp Hydro, but not SMUD
2: CAISO Total Hydro Generation Includes Pump Storage Units when their generation is positive, but not when they are pumping.
Source: Table 80 p. 185 Scott M. Harvey and William W. Hogan, Prepared Direct Testimony, FERC Docket EL00-95-075 March 3, 2003.

It can be seen in Table 9 that the Joskow-Kahn assumption regarding the level of hydro generation[41] on average substantially overstated the hydro generation available during the five high load deciles and understated the hydro generation available during the low load deciles. Replacing the Joskow-Kahn assumptions regarding hydro generation with the highest possible figure for actual hydro generation, results in an almost \$10/MWh increase in the simulated base case market price from \$85.47/MWh to \$95.43/MWh and raises the price from \$103.98 to \$117.46 under reserve model R5.[42]

Third, although it is not known exactly what figures Joskow and Kahn used for QF and geothermal generation, one can test the impact of replacing the output estimates used in the replication with the actual output data, again under the assumption that all of the unclassified units are hydro generation. Since it was possible to match the unit identifications for all of the units in the model that are dispatchable, the totals for the sum of the hydro, QF and geothermal

41 Joskow and Kahn describe their 8,500 as a Cal ISO estimate of hydro capacity available in their control area (Joskow-Kahn September 2002, p. 11), but a review of the source Joskow and Kahn cites makes it clear that this is not the case. The 8,500 MW figure was simply assumed by Joskow and Kahn without support and it is inconsistent with the actual data.

42 The uncapped price was \$115.09/MWh.

generation should be accurate, even if the breakdown between hydro and the other categories is not quite correct. Replacing the estimate of geothermal and QF with the actual hourly output per the Cal ISO data results in a further increase in the simulated competitive price from $95.43/MWh to $108.65/MWh in the base case and from $117.46 to $131.10 under reserve model R5.[43]

Fourth, it was found that total generation calculated from the confidential Cal ISO data was inconsistent with the publicly posted Cal ISO load data used in the July 16, 2002 replication of the Joskow-Kahn simulation. The confidential data is sometimes higher and sometimes lower than the public data, but appears to be lower on-peak and higher off-peak. It has not been possible to account for the discrepancy. In the course of other analyses, however, it has been observed that the new Cal ISO confidential output data reports zero output for some Mirant units on days on which the units were in fact operating at maximum capacity virtually around the clock.[44] If this kind of omission is not an isolated instance but reflects a more general problem with the confidential data produced by the Cal ISO, perhaps the new data are simply erroneous and this might account for the differences between Cal ISO load calculated based on the data produced by the Cal ISO in the refund proceeding and the load data posted on the Cal ISO website. Nevertheless, as a further sensitivity test of the simulations results, the model was reestimated using these alternative demand data. This reduced the estimate of the capped price for June 2000 to $93.89/MWh in the base case and to $115.25/MWh under reserve case R5.[45]

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[43] The uncapped simulated price was $139.60/MWh.

[44] For example, on January 5, 6 and 7 2001, the Cal ISO reported zero output for Potrero 3 and Pittsburg 2 but both Mirant's records and the EPA CEMS data show that these units were operating in every hour on these days and operating at maximum capacity for all but a few hours in the middle of the night.

[45] The uncapped price was $104.11.

Table 10
Sensitivity Cases
Capped Prices ($/MWh)

		No Reserves	R5 Reserve Model	R7 Actual Reserve Data
A	Corrected Imports and Generation	$85.47	$103.98	$98.79
B	A plus Corrected Hydro	$95.65	$117.46	$111.65
C	A plus Actual Hydro, Geothermal and QF	$108.77	$131.10	$123.96
D	C plus Alternative Load Data	$93.89	$115.25	$109.20

Source: Table 81 p 189 Scott M. Harvey and William W. Hogan, Prepared Direct Testimony, FERC Docket EL00-95-075 March 3, 2003.

Actual Hydro Reserves. The R5 model of operating reserve requirements discussed above is a significant improvement on the failure of the Joskow-Kahn and BB&W simulations to account in any way for operating reserve requirements. Nevertheless, the R5 model is highly approximate in terms of accounting for the available reserves on hydro generation and other resources. The final sensitivity analysis using the confidential Cal ISO data was to improve the model of reserves by replacing the assumption of roughly 500 MW of reserves on hydro resources with the actual amount of undispatched reserves on all units not dispatched in the model (i.e., hydro, geothermal and QF). The prices simulated under this assumption are reported in the R7 column of Table 10. This improved modeling of reserves reduces the simulated prices by roughly $5-$10/MWh relative to case R5, but the simulated prices remain $13 to $16 above the prices simulated not taking account of reserve requirements and are close to the actual prices prevailing in the Cal ISO and Cal PX markets during June 2000.

Simulation Sensitivity Summary

The simulation results reported in cases C and D for the R7 reserve model in Table 10 imply prices ranging from $109 to $123, in the range of the actual real-time prices which averaged $111 in the south and $117 in the North, strikingly higher than the simulated prices of $53 and $67 on which BB&W and Joskow-Kahn base claims that only the exercise of market power can explain the level Cal ISO electricity prices. Moreover, as a result of the constraints in the FERC proceeding, it was not possible to repeat the environmental, regulated unit output and NUG outage sensitivity cases from the July 16, 2002 paper using the confidential data. In the model based on public data, these sensitivities raised simulated prices by another $35/MWh relative to the base case (see Table 5), implying a simulated price level in the range of $145 to $160, well above actual real-time prices.

None of these simulations, however, is a full description of reality and all contain simplifications that may understate or overstate the competitive level of prices as summarized in Table 2. Thus, the range of uncertainty around the level of competitive prices is even greater than indicated by these simulation results. First, the simulations tend to overstate the competitive level of prices because none of these models or simulation cases fully take account of the impact of RMR contracts in depressing prices when RMR units are scheduled to operate at minimum load or units are dispatched out of merit.[46] Second, the simulations do not account for the impact of intra-zonal transmission congestion, which could either depress or increase actual prices. Third, the simulations tend to understate the competitive price level because they do not account for the impact of environmental restrictions other than the Delta Dispatch limits. In particular, no account is taken of the run time limits that applied to more than 1,000 MW of thermal generation. In addition, there is a range of uncertainty in the market price of NOx allowances during June 2000. The simulation replications used the same $10/lb. NOx allowance cost employed in the Joskow-Kahn simulation while BB&W apparently assume a lower allowance cost.[47] Fourth, none of the forced outage and derating adjustments are specific to the specific units in the model or take account of the actual level of use during June 2000. Fifth, the Cal ISO capacities used in some cases overstate or understate unit capabilities. Sixth, while some cases (RU02 and N3) account for the impact of start-up costs, minimum load costs, and operating inflexibilities in limiting supply, none fully account for the impact of these factors in keeping units on-line overnight in low-prices hours.[48] Seventh, the simulation models presume that prices are not only determined competitively, but in an efficiently structured market, with perfect communications and perfect dispatch. To the extent that the actual prices are affected by the

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[46] Data on RMR schedules and dispatch instructions are not public to our knowledge. Case E3 accounts for the impact of Delta dispatch restrictions and RMR instructions on the output of the Mirant units, but not on other market participants.

[47] BB&W 2000, p. 1399. BB&W apparently use the average price of all allowance transfers, including transfers between affiliates or to brokers, many of which are transferred at zero or nominal prices, so the BB&W allowance cost would be well below the market price estimates used by Joskow and Kahn.

[48] The comparison of on-peak and off-peak prices should account in part for this and we see little apparent impact, but some on-peak hours are low-price hours.

actual Cal ISO price determination rules, that the Cal ISO's dispatch was not perfect, that there were breakdowns in the transfer of data and instructions, actual prices may have been elevated by factors that are unrelated to the exercise of market power. Eighth, the Henwood heat rate and variable O&M cost data may over- or understate the true value.[49] Neither the Joskow-Kahn nor BB&W simulations, nor our replication account in O&M costs for the outage risks associated with operation at high capacity levels.[50]

Ninth, generation units in the Joskow-Kahn and BB&W models and in the replication are always able to operate at their full capacity absent forced outages or deratings. In practice, however, generation output varies with ambient temperature, water temperature and a variety of operating conditions (including tides and condensors clogged with sea life). Moreover, in these simulations, generators can instantly adjust their output as demand rises, while in the real-world generators have ramp constraints, which sometimes require more expensive generation to be dispatched, raising prices for portions of an hour. Tenth, all of these simulation models treat hydro generation as price taking, which is not necessarily accurate and this tends to understate the competitive price level.[51]

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49 For example, all of the simulations used the unadjusted Henwood variable operating and maintenance costs described by Joskow and Kahn. This data base had zero variable O&M costs, probably reflecting missing data, for the Mirant combustion turbines Potrero 4, 5 and 6. Actual third-party vendor operating and maintenance charges incurred to keep these units operating over the period January 1 to May 31, 2001 amounted to $37/MWh and Mirant incremental staffing costs would have raised this figure further. Similarly, the very high forced outage rates for some of the older units under utility operation, such as Pittsburg 1-4 in Table 6, suggest that the actual variable operations and maintenance costs per MWh was substantially higher than assumed in these simulations.

50 Moreover, neither the Joskow-Kahn nor BB&W simulations take account of the impact of Cal ISO dispatch and pricing rules on the incremental costs of GTs and CTs. Once started, GTs and CTs should generally operate for an hour or more before being turned off. As a result, the incremental cost of being dispatched by the Cal ISO for one interval is far higher than the average hourly cost. The NYISO, PJM, and ISO-NE all address this problem through a bid production cost guarantee that assures the GT/CT owner that if the unit is dispatched by the ISO to operate and prices subsequently decline, making its operation uneconomic, the generation owner will be made whole for its as-bid cost over its minimum run time (i.e., it will be paid its bid if that turns out to exceed the average hourly price). This bid production cost guarantee makes it economic for a generation owner to offer its capacity at its average hourly cost. The Cal ISO market rules did not provide a similar guarantee, so the incremental cost of GTs and CTs supplying output in a dispatch interval could greatly exceed their average hourly cost, which would be reflected in the offer price of a competitive supplier.

51 BB&W 2002 argue that this treatment is appropriate on the grounds that the optimal hydro schedule would equate the marginal value of water across periods; see Appendix C. Their argument, however, abstracts from several elements of hydro generation that invalidate their conclusion. Five considerations are important. First, the model on which they base their conclusions assumes that the release of a given quantity of water permits the generation of the same amount of power in all periods permitting an equivalence between a unit of water and

Eleventh, none of these simulations models adequately account for the occasional turmoil of real-time operations. In the simulations there are no surprises that require load to be met with high cost generation, while the real world is filled with such shocks. Table 11 reports the mean, median and variance in load and prices for the 10 load deciles. It is noteworthy that the variation within these deciles tends to be materially lower in the simulated models than in the real-world, aside from the highest deciles, and dramatically lower in the base case simulation. In fact, virtually none of the variation in real-time prices at a given load level is explained by the factors accounted for in the base case simulation.[52]

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the marginal cost of generation. In practice, however, it is understood that the operation of hydro generation at very high capacity levels sometimes reduces the efficiency of the generation in terms of quantity of water released per MW. Thus, if a given quantity of water could generate 1 MW worth $250 in the future, but would only generate 1/2MW if released during the current hour, then the price of that power is $500/MWh less an adjustment for the time value of money. Second, the BB&W model does not account for the value of ancillary services. If using water today reduces pondage to the point that the hydro facility would not be able to provide reserves for several hours or days or raises the risk of being put in this situation, then the marginal cost of using the water today could greatly exceed the future value of the energy alone generated with that water. Third, some of the hydro systems in the west involve a series of reservoirs that must be jointly optimized. The release of water in one reservoir during a particular hour may earn the market price of power for the energy generated in that hour, but may require generating using that water in downstream dams at fixed points in time in the future that may not have high value. When these kinds of interactions are present, the shadow price of releasing the water for current generation may greatly exceed the price of energy in any single future hour. Fourth, the BB&W model assumes that the release times for water are optimized solely for electric generation. This is also not necessarily the case, and levels of hydro-generation that entail sacrificing other uses would be offered only at a premium to the marginal value of the future generation alone. Fifth, the result that the value of hydro generation is capped by the cost of thermal generation assumes that the marginal cost of thermal generation defines the value of power. This assumption is not valid in circumstances in which the value of consumption defines the value of power. The market price of power can greatly exceed the variable cost of incremental thermal generation in periods in which there is insufficient capacity and load serving entities with insufficient capacity risk involuntary load shedding or if load serving entities are making payments to consumers to reduce consumption in order to avoid involuntary load shedding. All of these considerations were likely relevant at times to the offer prices of various western hydro resources. They may not have been important at all times for all producers and some may not have been important considerations for the California hydro generation of PG&E and SCE but this is an empirical question. The assumption that hydro is price taking is therefore not conservative but rather understates the competitive price. The alternative approach of using the actual offer prices of energy limited hydro resources would conversely likely overstate the competitive price level if market power was being exercised. The reality is that the modeling of energy limited hydro introduces a band of uncertainty of unknown magnitude into the simulation analysis.

52 The sensitivity case reported in Table 11 has much higher than actual prices and much higher than actual price variances for the load decile 4. This is a likely result of Joskow-Kahn hydro assumptions, which shift hydro from the low and moderate load hours into the high-load hours, causing price spikes in the low and moderate load hours when actual reserve requirements are modeled.

Table 11
Load and Price Data by Decile for June 2000

Decile*	Statistic Type	Modeled Load (103% of Load and Losses)	Real-Time NP15 Price ($/MWh)	Real-Time SP15 Price ($/MWh)	Base Case Price ($750 Cap)	7500 Hydro R5H3E3N3RUO2_10 Price ($750 Cap)
10	Mean	41,904.14	550.82	542.78	345.65	613.98
	Standard Deviation	1,274.55	271.29	269.50	273.42	238.88
9	Mean	38,162.97	194.74	183.20	66.26	253.75
	Standard Deviation	927.18	193.81	174.41	13.86	233.73
8	Mean	35,591.99	120.23	111.15	56.58	92.56
	Standard Deviation	591.70	137.50	126.18	3.27	112.40
7	Mean	33,570.36	75.00	71.98	53.42	58.96
	Standard Deviation	620.25	63.11	63.75	3.96	7.19
6	Mean	31,552.46	66.90	52.78	53.86	55.28
	Standard Deviation	531.06	93.07	49.01	4.99	6.11
5	Mean	29,526.09	54.56	53.26	56.31	54.37
	Standard Deviation	632.42	48.68	47.29	4.00	3.29
4	Mean	27,411.97	76.52	64.53	53.24	95.47
	Standard Deviation	730.07	104.81	74.59	2.52	143.39
3	Mean	25,041.32	66.56	57.46	49.38	51.19
	Standard Deviation	662.35	52.51	34.05	4.72	5.25
2	Mean	23,193.91	49.16	41.21	46.41	48.20
	Standard Deviation	516.03	30.67	29.45	6.02	6.63
1	Mean	21,366.53	60.99	41.12	45.21	47.33
	Standard Deviation	657.77	24.06	26.20	4.66	5.17
	Total Mean	30,732.18	131.55	121.95	82.63	137.11
	Total Median	30,662.00	71.80	66.72	53.95	55.16
	Total Standard Deviation	6,386.85	193.16	187.06	123.49	208.19

* The definition of load deciles is consistent with Joskow-Kahn (10 = Highest, 1 = Lowest)

Overall, Table 11 suggests that much of the variation in market forces that is driving real-time prices is not included either in the base case simulation or in the sensitivity cases. It is possible that omitting the factors that account for 90% or more of the variation in real-time prices would not skew the simulated prices up or down on average, but absent analysis there is no basis for assuming that.

These simulation results suggest that much more detailed simulation models, much more firmly grounded in actual data and power system operating conditions would be necessary to distinguish between competitive and shortage explanations for the historical level of electricity prices in California during June 2000. The apparent sensitivity to assumptions and unknowns reveals a range of error that is both substantial and material. These data problems and ambiguities also illustrate the difficulty in drawing conclusions regarding market performance from simple benchmarking models, given the range of data problems encountered in replicating the Joskow-Kahn and BB&W studies. Given these sensitivities, and the many real complications in the electricity system set aside in the simplifications of these models, it is not possible to separate out the effect of the evidence of the exercise of market power and the errors in the model. The margin of error is larger than the effect being estimated.[53]

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[53] Frank Wolak has suggested that the increase in NOx allowance costs reflected an exercise of market power rather than being the inevitable consequence of the dramatic reduction in western hydro generation and California power imports (see Jonathan Kolstad and Frank Wolak), "Using Environmental Emissions Permit Prices to Raise Electricity Prices: Evidence from the California Electricity market," May 2003. Dr. Wolak's theories are inconsistent with the data. It is indisputable from the data reported by the South Coast Air Quality Management District (see Annual Reclaim Report for the 2001 Compliance Year pp 3-4) that the increase in NOx allowance prices was driven by a real increase in NOx emissions by power generators and purchases from other emitters rather than by purchases and stockpiling of unused allowances. Moreover, it is unambiguous that the increase in NOx allowance prices reflected the actual market prices of allowances, rather than a reflection of sham transaction prices. It was the concerns of non-generator NOx emitters over the high cost of NOx allowances that caused SCAQMD to separate power plants from the NOx allowance program in Spring 2001 in order to allow other industries to emit NOx at lower costs than the generation industry. There would have been no need for such a step if these price increases were not real.

Dr. Wolak, however, suggests that his finding that SCAQMD generators paid higher prices than other NOx emitters for NOx allowances during 2000 and 2001 (Kolstad and Wolak pp. 16-18) suggests some kind of competition problem. This pattern, however, is the natural consequence of the supply and demand changes described above. It is apparent from SCAQMD data that as prices rose beginning in mid 2000 it was power generators that were allowance buyers and other emitters that were the sellers. It is hardly remarkable to find that power producers paid higher average prices over the year than other emitters for allowances during 2000 as the other emitters became sellers rather than buyers once prices rose. Since Dr. Wolak's model does not control for the month in the year in which the NOx allowances were purchased, how could the 2000 data show anything other than what Dr. Wolak and Kolstad found. In 2001, power generators paid higher prices than other emitters because the SCAQMD split the Reclaim market between power generators and other emitters precisely to achieve this result of allowing other emitters to buy allowances in a separate market at lower prices.

Dr. Wolak also suggests that it is evidence of manipulation of the Reclaim market that the power generators in SCAQMD generated more power in the real world than predicted by Dr. Wolak's model of the industry (Kolstad and Wolak, pp. 18-23). Dr. Wolak finds that the power generators located in SCAQMD generated more power in the real world than predicted by his model. This is hardly surprisingly, however, because his model (the BB&W model) generates predicted prices that are far below actual real world market prices. At the higher real-world prices, the SCAQMD generators produced larger outputs than his model predicts at low prices. As shown above the low simulated on peak prices in Dr. Wolak's model likely reflect a failure to account for output limitations such as the Delta dispatch, start-up costs, and misstatement of the available capacity of regulated utility generation. Off-peak, his simulation undoubtedly predicts lower output by SCAQMD units than observed in the real world because his model ignores physical unit characteristics and assumes that SCAQMD units can be turned off in any hour in which the market price declines below their incremental costs, while real world units had to remain on line at minimum load, thus generating more than predicted by Dr. Wolak's model.

Third, Dr. Wolak found that there was a poor correlation between his measure of NOx allowance costs and his estimate of implied firm marginal costs based on Cal ISO prices and his estimated residual demand elasticity over the period 1998-2000. This is not surprising since the methodology and computer programs that Dr. Wolak utilizes to estimate the residual demand elasticity yield extremely low values thus leading to marginal cost estimates that are far below actual prices during high priced periods. Not surprisingly, Dr. Wolak then finds that during the period in which both NOx allowance prices and actual prices were high, his estimate of marginal cost does not reflect the actual level of NOx allowance costs. A more informative test would be to assess whether the variations in NOx allowance and gas costs were consistent with actual power prices. Even this test, however, would be problematic for other reasons. First, during the period of high NOx allowance prices in the fall of 2000 that is included in Wolak's analysis, Cal ISO electricity prices were, at Dr. Wolak's recommendation, capped at levels that were often below the incremental costs of high NOx emitting generating

On the other hand, it is not claimed that the sensitivity analyses show that no market power was ever exercised in California electricity markets. The simulation results in the July 16, 2002 paper and those based on the confidential data are derived from a single stack dispatch model that does not account for all of the factors impacting the real-time dispatch, and do not provide a reliable method for assessing whether market power has been exercised. Moreover, even if the general price level is consistent with competitive supply and demand forces, it is possible that market power may have been exercised by particular market participants, at particular locations, in particular hours, without noticeably impacting overall prices. The point of these simulation sensitivity tests is that the actual level of prices is broadly consistent with supply and demand factors and thus that there is no basis for asserting that these prices could only have arisen from the exercise of market power and that the exercise of market power, rather than supply and demand factors aggravated by absolutely terrible public policy decisions, accounts for the high prices.

C. NEPOOL Simulations

Although the focus in this paper has been on the California data and simulations, the same methodological difficulties appear in applications in other markets. The systematic bias of these benchmarking studies towards understating prices under tight supply and demand conditions is demonstrated in a dramatic manner by a study of NEPOOL prices by Bushnell and Saravia. This benchmarking study applies the Joskow-Kahn and BB&W methodology to the markets coordinated by ISO New England. As in the other studies, the Bushnell-Saravia study found that the prices simulated using offer prices based on estimated marginal costs were well below the actual market price during months with high average price levels as shown in Table 12. It is striking that the Bushnell and Saravia study even finds a spread between actual and simulated prices in a region in which most observers, including the market monitor using different

plants requiring that the Cal ISO provide additional compensation for the operation of these units. Second, while Dr. Wolak's analysis is based on daily gas price data whose variations would be reflected in daily power prices, there is no similar daily index of variations in NOx allowance prices. Instead, we have only rough measures of the actual NOx allowance prices that are measured with considerable error, downward biasing the coefficient estimates.

methods, have concluded that actual settlement prices have been artificially depressed by inefficient rules that give rise to substantial uplift costs.[54]

The Bushnell-Saravia study is important because it includes a particularly informative sensitivity test made possible by access to the actual market offer prices. Significantly, the Bushnell-Saravia study also applied the benchmarking simulation methodology to simulate prices using actual offer prices, rather than estimated marginal costs. Since the exercise of market power through economic withholding entails offering capacity into the market at inflated offer prices, if the simulation model were accurately simulating the operation of the power system, and high prices were due to the exercise of market power, then replacing the estimated cost-based offer prices in the simulation with the actual presumably inflated offer prices should produce simulated prices similar to actual prices. Strikingly, Table 12 shows that the market prices simulated using actual offer prices were also well below actual market prices, and in several high-priced months actually averaged lower than the prices simulated based on marginal costs. The implication of this result is that the factors causing high prices were not high offer prices by the marginal suppliers in the Bushnell-Saravia benchmarking model, but were instead factors not accounted for in the benchmarking model. This clearly demonstrates the reality that these benchmarking models, such as those utilized by Joskow-Kahn and BB&W, have the ability to find large gaps between the actual and simulated market price even if market participants are not exercising market power.

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54 David B. Patton, "An Assessment of Peak Energy Pricing in New England During Summer 2001," November 2001. Mario Depillis, ISO-NE, "Reserve Market Issues in Nepool," September 13, 2000; Mario Depillis, ISO-NE, "Limitations of Bid Characteristics," October 24, 2000; ISO New England, Inc., "Management Response to Summer 2001 Pricing," March 2002; ISO New England, "Power Supply," no date; and David Patton, Robert Sinclair and Pallas Van Schack, "Competitive Assessment of the Energy Market in New England," May 2002.

Table 12
Actual and Simulated NEPOOL Prices ($/MWh)

	Actual Average Price (A)	Simulated Prices	
		Marginal Cost Offer Prices (B)	Actual Offer Prices (C)
June 1999	49.18	30.08	29.12
July 1999	41.14	31.11	29.32
May 2000	72.78	34.12	42.61
July 2001	52.24	32.13	31.38
August 2001	43.34	36.56	38.37
Average	51.736	32.82	34.16

Source: Bushnell and Saravia, Table 3, p. 14 and Table 4, p. 15.

III. WITHHOLDING ANALYSIS

A. Introduction

An alternative approach to identifying the exercise of market power is to more directly address the question of whether market power has been exercised by testing whether high prices are associated with strategic withholding of output (i.e., a failure to utilize capacity whose output would have been economic to produce at observed prices). A pathbreaking contribution of Joskow and Kahn to the empirical analysis of the exercise of market power was to utilize output data for electric generators collected by the EPA to attempt to test whether available thermal generating capacity in California was withheld from the market during high priced hours in 2000. Robert Reynolds subsequently filed testimony in a FERC proceeding that similarly attempted to test for withholding, using confidential Cal ISO output data that was made available in this proceeding. While Joskow-Kahn and Dr. Reynolds concluded that high prices during the summer of 2000 reflected strategic withholding, replication of these analyses leads to the conclusion that the evidence is in some cases ambiguous and in others cases indicates that, at most, only minimal economic withholding could have been present.

The methodological issues are somewhat different between the Joskow-Kahn and Reynolds analyses but they basically entail the need in identifying the exercise of market power for withholding analyses to: (1) take account of environmental operating limits; (2) take account of unit operating characteristics such as ramp limits, and start-up times; (3) take account of real-time unit operating problems; (4) accurately measure incremental costs; and (5) take account of system operator dispatch instructions, particularly during reserve shortage conditions. The discussion begins with the Joskow-Kahn analysis and then turns to Dr. Reynolds' analysis.

B. Joskow-Kahn Withholding Analysis

An important contribution of the series of papers by Joskow and Kahn on California electricity prices has been the use of EPA data to test whether available thermal generation was withheld from the market during high priced hours during the summer of 2000. Joskow and Kahn study the hours in June 2000 for which the real-time price exceeded a threshold and compare the electricity output posted by the EPA to the estimated capacity of the units. Their analysis then posits that any difference between actual and potential output can be attributed only to: 1) capacity used to meet ancillary service requirements; 2) capacity out of service due to forced outages; 3) capacity not available due to inter-zonal transmission constraints, and 4) economic or physical withholding of capacity.

Joskow and Kahn calculate an output gap (the difference between capacity and output) for steam units without regard to their on-line status and find that the gap they calculate greatly exceeds the Cal ISO ancillary service requirements in SP-15 (Tables 7 and 8), implying that the gap must include substantial capacity that is not providing reserves. They also compare the output gap for on-line units to the ancillary service requirements and again find an output gap, although much smaller than in the initial calculation (Table 9). This withholding analysis omits many of the same operating limitations that are omitted in the simulation analysis, such as environmental operating limits, unit ramp limits, unit operating problems and Cal ISO dispatch instructions (summarized in Table 2) could account for part of the difference between output and capacity. In replicating their analysis, it was found that the conclusions were sensitive to these omissions. Moreover, it is shown that the Joskow-Kahn methodology identifies an output gap, even during hours of Stage 1 emergency in which it is known that ancillary service requirements were in fact less than the available capacity, demonstrating that their methodology must overstate available capacity.

The tables below are based on an earlier paper which commented on a Joskow-Kahn paper that used a slightly different sample of hours than described in their Energy Journal article.[55] This choice was made because it was not possible to identify the sample of hours utilized for the analysis reported in the Energy Journal and it was thought better not to confound straight-forward methodological issues with this inability to replicate their analysis.[56]

Prior papers have replicated the Joskow-Kahn withholding analysis and observed that much of the apparent output gap they identify was attributable to several factors:

1. Some of the hours with high real-time prices were immediately before or after low priced hours or dispatch intervals or even included low-priced dispatch intervals. Competitive firms that were following the Cal ISO's dispatch instructions should be expected to be ramping up or down during part of such hours, reducing their average output and giving rise to an apparent output gap.[57] Units just coming on-line also appeared to have an output gap until they reached full operating pressure and were able to ramp to full output.

2. The Joskow-Kahn output gap calculation made no allowance for unit deratings, short of complete outages, or other temporary output limitations.[58]

3. The Joskow-Kahn output gap calculation made no allowance for environmental output limits such as the Delta Dispatch.[59]

4. The Joskow-Kahn output gap calculation was based on capacity measures that did not necessarily measure capacity under normal conditions or for sustained operation.[60]

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55 Joskow and Kahn July 2001.

56 Joskow and Kahn 2002 state that the sample is based on hours when the real-time price exceeded the 17,000 Btu heat rate threshold, and Table 5 identifies 104 such hours (p. 19). There were, however, 233 hours during June 2000 in which the real-time price in NP 15 exceeded $89/MWh and 181 hours during June 2000 in which the real-time price in SP-15 exceeded $95. Moreover, the real-time price exceeded both thresholds during 181 hours.

57 See Table 21 and 22 Harvey-Hogan April 2001.

58 Harvey-Hogan April 2001, pp. 51-52.

59 Harvey-Hogan April 2001, pp. 51-52.

60 Harvey-Hogan April 2001, pp. 64-66.

Tables 7 and 8 in Joskow-Kahn (September 2002) report the difference between the total capacity and output of the various non-utility generators during the high-priced hours they analyze and find that the difference (the output gap) greatly exceeds both the total ancillary service requirement and undispatched ancillary service capacity in SP-15. Joskow and Kahn further suggest that this output gap must reflect either "a very large outage rate" or withholding.[61] This conclusion is mistaken. Joskow-Kahn Table 7 includes all hours in which the average real-time price exceeded their threshold i.e., every real-time price spike, even if the price spike occurred on a day on which day-ahead prices were relatively low (and thus it would not have appeared economic to start the unit or keep it on-line overnight), yet the calculated output gap includes the capacity of offline units. Simply assuming that all units would be on line in real time to respond to price spikes, even when the day-ahead price was low is not a meaningful test of strategic withholding, as units may have been off-line during these hours either as a result of outages, economics or simply a lack of perfect foresight. The failure of generators to operate could therefore reflect a lack of perfect foresight, poor economics or forced outages, as well as possible withholding.[62]

Table 9 in Joskow-Kahn September 2002 accounts for the operating status of generators in Test 1, which only includes the capacity which was actually on line during those hours. In this data, the June "output gap" in SP-15 falls from 3,913 MW in Table 7 to 1,770 MW in Test 1 in

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61 Joskow-Kahn September 2002, p. 23.

62 It has been shown in prior papers that the data suggest that it would likely have been unprofitable for a number of units to have operated on June 1-11, 16, 17, 21 and 23 despite a few high-priced hours. Joskow-Kahn Table 8 includes hours with real-time price spikes on days with low prices, such as hour 22 on June 1; hours 16 and 17 on June 6; hours 15 and 16 on June 20; and hours 17, 18, 19 and 20 on Sunday, June 25. See Harvey-Hogan December 2001 and Harvey-Hogan July 2002.

Table 9.[63] A similar reduction in the apparent output gap calculated for all hours with high real-time prices during June 2000, in the replication of their analysis is portrayed in Table 13 below.[64]

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63 Joskow-Kahn also include two other tests. Test 2 includes capacity if it was on-line at some point during the day of the high priced hour, even if the unit was off-line during the actual high priced hour. The output gap calculated in this manner therefore includes the capacity of units came on line after the high priced hour, and units that suffered forced outages prior to the high priced hour. Joskow-Kahn's test 3 also includes units that were off-line during the high priced hour but were on-line during the prior day. It therefore includes both capacity that suffered forced outages on the prior day, as well as capacity that was uneconomic to keep on-line at minimum load overnight.

64 Compare columns C and F in Table 13. Tables 13 and 14 are based on the $120 threshold employed in prior Joskow-Kahn withholding analyses. Joskow and Kahn 2002 argues that a lower threshold would accurately reflect the costs of most units during June 2000, but several doubtful assumptions are made in arriving at that conclusion. First, they assume that perceived cost of NOx allowances was no higher than $10/lb. in June 2000 (Joskow-Kahn September 2002, pp. 18, 23). This assumption is more likely true at the beginning of the month than at the end. The reality is that any allowances sold for $10/lb. in June were worth $20-$30/lb. by July and $45-$50 by November-December, so it is a significant assumption to assert that no one had correct expectations regarding the actual cost of emission allowances in late June.

Second, the emissions rate they assume, 1 lb/MW, is below the emissions rates of a number of the steam units included in the withholding analysis. The Joskow-Kahn suggestion that high emissions rate units only provide reserves is inapplicable to steam units (Joskow-Kahn September 2002, p. 23), as those units must be on-line to provide reserves at all, and can only provide a limited quantity of reserves when on-line because they would be ramp-limited. There would therefore be an output gap on these units unless the price were high enough to warrant dispatching the units above minimum load.

Third, the Joskow-Kahn calculation of the threshold for economic withholding assumes zero variable O&M costs (*i.e.*, non-fuel variable costs), which unambiguously understates such costs and their calculation also makes no allowance for carrying costs, which also rose with fuel and emissions costs. Fourth, the Joskow-Kahn calculation of gas costs is based on a monthly average spot price but spot gas prices varied over the month, from $4.22/mmBtu to $5.105/mmBtu plus transportation in the Socal Gas territory and from $4.37/mmBtu to $5.09/mmBtu at the PG&E city gate. The assumed intrastate gas transportation charge for Southern California units (apparently $.28/mmBtu) also appears to be low for at least some units. Etiwanda, for example, paid charges of $.46/mmBtu. Affidavit of Brian McQuown, Exhibit Re 150, Docket #EL00-95-069, p. 3. Gas prices tended to be higher at the end of the month of June, which was also the period with high electricity prices. Using a monthly average gas price therefore understates costs on some of the high priced days by more than $7/MWh at the assumed 17,000 Btu/kWh heat rate. Fifth, the Joskow-Kahn calculation makes no allowance for unfavorable variations in heat rate performance either due to unit problems or ambient temperature conditions.

Sixth, the lower the threshold price, based on the average hourly price that is applied to the unit, the more likely it is that the actual dispatch price was below the actual costs of the unit for one or more dispatch intervals during the hour, or during the prior hour. Thus, the Cal ISO real-time price could average $90 for an hour if the price during the first two dispatch intervals was only $75, rose to $90 for two dispatch intervals and then rose to $105 for the final two dispatch intervals. The Joskow-Kahn methodology would identify an output gap in such an hour, yet the unit's offer price might have been exactly equal to its incremental costs and it would have been fully dispatched for only two-thirds of the hour.

77 hours were identified during June 2000 in which there was no congestion and the NP-15 real-time price ranged between $89 and $120/MWh, and 54 hours during which the SP-15 real-time price ranged between $95 and $120/MWh. Forty-four of the 77 hours in the North (NP-15) and 32 of the 54 hours in South (SP-15) included dispatch intervals with incremental prices below the thresholds, and additional hours had decremental prices that were below the thresholds and sometimes even negative.

Table 13
Output Gap for Non-Ramping Hours (MW); Real-Time Prices > $120/MWh
(Excluding Capacity of Off-Line Units)

	All High-Priced Hours						High-Priced Non-Ramping RT Hours, Adjusted for Outages		
	All Units			On-Line Units					
Owner	Maximum Output (A)	Mean Output (B)	Output Gap (C)	Maximum Output (D)	Mean Output (E)	Output Gap (F)	Maximum Output (G)	Mean Output (H)	Output Gap (I)
NP-15									
Duke	1,526	1,405	121	1,463	1,405	58	1,441	1,378	63
Mirant	2,719	1,921	798	2,527	1,921	605	2,567	2,255	312
Total	4,245	3,326	919	3,990	3,326	664	4,009	3,634	375
AS Procurement (excl. replacement)									1,092
AS Procurement (incl. replacement)									1,649
Undispatched AS									1,197
SF									
Mirant	213	157	56	208	157	51	210	160	50
AS Procurement (excl. replacement)									33
AS Procurement (incl. replacement)									61
Undispatched AS									28
SP-15									
AES/Williams	3,681	2,515	1,166	2,960	2,515	445	2,974	2,658	316
Duke	733	611	122	690	611	80	716	674	42
Dynegy	2,000	1,033	967	1,538	1,033	504	1,561	1,191	370
Reliant	3,487	2,267	1,220	3,107	2,267	840	3,178	2,446	733
Total	9,901	6,426	3,475	8,295	6,426	1,869	8,429	6,969	1,460
AS Procurement (excl. replacement)									1,164
AS Procurement (incl. replacement)									2,100
Undispatched AS									1,503
Z-26									
Duke	1,037	960	77	1,037	960	77	1,037	996	41
AS Procurement (excl. replacement)									34
AS Procurement (incl. replacement)									78
Undispatched AS									31
Cal ISO Total	15,396	1,869	4,527	13,529	10,869	2,660	13,685	11,759	1,926
AS Procurement (incl. replacement)									2,323
AS Procurement (excl. replacement)									3,888
Undispatched AS									2,759

Note: The calculations use NP-15 prices for Northern zones and SP-15 prices for Southern zones to identify high-priced hours.
Sources: Ancillary service data from Cal ISO website.
(A), (B), (D), (E), (G), (H): CEMS data, adjusted for Daylight Savings Time
(C): Col. (A) – Col. (B) (F): Col. (G) – Col. (H). (I): Col. (G) – Col. (H)

The calculations in Tables 13 and 14 also do not include a few non-CEMS units which Joskow-Kahn included in their calculations based on the EHV data sources they refer to which are not publicly available. GT capacity is also not included in this analysis. Joskow-Kahn determine GT output and the output gap based on BEEP stack instructions but units dispatched by the Cal ISO RMR desk would not appear in the BEEP stack instructions. In addition, once units had been dispatched on, they would continue to operate for their minimum run time, even if they subsequently became uneconomic and were not dispatched in the BEEP stack. It is therefore not possible to determine the output of these units from the BEEP stack data. Moreover, as noted

The calculated output gap on on-line units in Joskow-Kahn Table 9 and column F in Table 13 above for SP-15 still exceeds the level of undispatched ancillary services, although the size of the "output gap" is greatly reduced. The output gap calculated in this manner, however, includes the "output gap" attributable to the normal ramping of units from lower to higher output levels as prices rise. If the output gap, in fact, reflects physical or economic withholding rather than merely the inability of real-world units to instantly adjust output then one ought to detect the same output gap if the analysis is limited to hours of sustained high prices. This is not the case, however. If the output gap is recalculated excluding high real-time price hours following or preceding hours with average prices below $120, then the gap falls by almost an additional 300 MW in NP-15 and more than 400 MW in SP-15 as also shown in Table 13 above. The calculated output gap for SP-15 averages less than undispatched ancillary service capacity but more than procurement excluding replacement reserves [65] The calculated output gap is 1,614 MW smaller in the high-priced, non-ramping hours than in the high-priced ramping hours and the difference is statistically significantly different from zero at the 99.9 percent confidence level.

The data in Column I of Table 13 continue to indicate the existence of an "output gap," but during hours of sustained high prices the calculated output gap is less than ancillary service procurement from generation in NP-15 and for the Cal ISO overall, as well as less than the

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above, the incremental cost of dispatching these units greatly exceeded their average hourly cost, because the lack of a bid production cost guarantee in the California market.

65 Table 13 also includes a calculation of undispatched ancillary service capacity. It should be noted that the calculation of "undispatched ancillary services" is only approximately correct. First, the BEEP dispatch was not always operational in June 2000 and instructions were at times relayed by phone. It is not clear that the posted BEEP data are accurate for all of the high-priced hours. Second, hours have been found in which units supposedly providing spinning or non-spinning reserves were generating energy rather than providing reserves, the BEEP was operating and the dispatch of these units is not reported in the published BEEP dispatch data. One circumstance that can produce this outcome would be an RMR unit that is instructed to increase output in real time and chooses to be paid the market rather than the contract price. The unit's real-time output in excess of day-ahead schedules would apparently be treated by the Cal ISO as uninstructed output and no BEEP instruction would be recorded. A RMR unit could apparently be instructed to go to the top in the morning, run at capacity all day, and never show up as dispatched in the BEEP stack. In this circumstance, the measure Joskow-Kahn July 2001 introduce of capacity providing ancillary services would be conservative. While the Joskow-Kahn approach to calculating undispatched ancillary services is useful, it should be kept in mind that it provides only an approximate measure of the undispatched capacity providing reserves. In addition, the amount of undispatched ancillary services does not necessarily provide an accurate measure of capacity dispatched down by the Cal ISO to maintain reserves, as during emergency conditions, the operators may choose to in practice carry system reserves on units that were not so designated prior to the hour.

calculated undispatched ancillary service capacity. In other words, the capacity not used to generate energy could have been supplying required ancillary services. On the other hand, a substantial amount of the regulation and reserve requirement in NP-15 would likely have been met by undispatched hydro capacity, so the calculated output gap could reflect withholding, even if the calculated output gap is less than ancillary service requirements. Joskow and Kahn conclude that the output gap provides"sufficient empirical evidence to suggest that the high observed prices reflect suppliers exercising market power."[66] The data do not support such a conclusion however, and could be consistent either with withholding (if substantial ancillary services were provided by other generation) or with little or no withholding (if a smaller amount of ancillary services were provided on other units and depending on the amount of the output gap that is attributable to omitted factors.

The output gap in Column I in Table 13 could be attributable to a variety of omitted factors. First, the actual capacity available to the Cal ISO market may be less than the capacity assumed by Joskow and Kahn for several reasons. These considerations include Mirant capacity at Pittsburgh and Contra Costa that was not offered because dispatch would require operation above the expected 86 degree water temperature limit, capacity not offered because of deratings, and any difference between the capacities assumed by Joskow-Kahn and actual operating capacity. Second, actual output could also differ from the capacity offered into the Cal ISO market for a variety of reasons. These causes could include energy economically withheld through high-offer prices or environmental limits such as the 86 degree limit that bound at lower than expected output levels in real time, operating conditions that prevented a unit from operating at full capacity, (such as air or water temperature or tides, the output gap on units coming on-line,[67] or cooling system limitations), serious operating problems that required substantial output reductions, ISO dispatch instructions, as well as mismetering in the CEMS

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[66] Joskow-Kahn 2002, p. 29.

[67] For example during the heat wave of June 26-June 28, El Segundo 1 and 2 came on-line during the day on June 27, and part of the overall output gap is due to those units as they ramped up. Similarly, El Segundo 3 and Redondo 5 came on line during the day on June 28, Alta 3-1 and 3-2 came on-line during the day on June 26 and South Bay 4 came on-line during the day on June 28.

data,[68] so undispatched capacity not providing ancillary services may not actually reflect economic withholding.[69]

The data required to fully adjust the calculated output gap for these factors are not available, but one can gain a degree of insight into their magnitude by calculating the output gap for the hours in which the Cal ISO was operating under a stage 1 or higher level emergency and for the non-emergency hours. The significance of this distinction is that a stage 1 emergency declaration indicates that there was a shortage of capacity *at any price*. Table 14 reports the calculated output gap for the high-priced, non-ramping hours of stage 1 or higher emergency. It can be seen that the calculated output gap averages 218 MW in the North and 1,422 MW in the South during these hours in which it is known that there was not enough capacity available at any price, and thus that there was a true shortage, not economic withholding.[70] The calculated output gap on the steam units is generally higher than ancillary service procurement (other than replacement reserves) but lower than the calculated undispatched ancillary services. Thus, the Joskow-Kahn methodology indicates the existence of economic withholding rather than shortage during hours in which we know the system was, in fact, short of capacity, so the methodology yields demonstrably incorrect conclusions regarding economic withholding.

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68 Some anomalies have been found in the CEMS data suggesting that the output reported in the CEMS data for some units may be understated. The CEMS data measures the gross output of the units (i.e., including electricity used by the generating plan) and therefore should always exceed the net output. Alamitos 1-6 reported a net output to the EIA that was 2.5 percent greater than the gross output for the CEMS data in June 2000, while Encina reported a net output that was 6 percent higher than the CEMS data and Etiwanda reported a net output that was 1.3 percent higher than the CEMS data.

69 Many of these same factors were cited by the Cal ISO in commenting on a CPUC analysis of available capacity.

70 The data presented do not exclude the possibility that the shortage conditions could have been a result of physical withholding. Physical withholding issues are discussed in Section V.

Table 14
Output Gap (MW) Real-Time Prices > $120/MWh
June 2000

Owner	High-Priced Non-Ramping RT Emergency Hours, On-Line Units			High-Priced Non-Ramping RT Non-Emergency Hours, On-Line Units		
	Maximum Output (A)	Mean Output (B)	Output Gap (C)	Maximum Output (D)	Mean Output (E)	Output Gap (F)
NP-15						
Duke	1,467	1,427	41	1,410	1,321	89
Mirant	2,626	2,449	177	2,498	2,026	472
Total	4,093	3,875	218	3,909	3,348	561
AS Procurement (excl. replacement)			943			1,268
AS Procurement (incl. replacement)			1,637			1,663
Undispatched AS			1,104			1,307
SF						
Mirant	213	141	72	207	184	23
Total	213	141	72	207	184	23
AS Procurement (excl. replacement)			26			41
AS Procurement (incl. replacement)			65			56
Undispatched AS			29			27
SP-15						
AES/Williams	3,023	2,699	324	2,910	2,605	305
Duke	733	704	29	693	634	59
Dynegy	1,602	1,268	335	1,507	1,091	416
Reliant	3,328	2,593	734	2,984	2,253	731
Total	8,686	7,265	1,422	8,095	6,584	1,511
AS Procurement (excl. replacement)			1,252			1,050
AS Procurement (incl. replacement)			2,359			1,763
Undispatched AS			1,671			1,284
ZP-26						
Duke	1,037	996	41	1,037	997	41
Total	1,037	996	41	1,037	997	41
AS Procurement (excl. replacement)			42			22
AS Procurement (incl. replacement)			92			60
Undispatched AS			39			16
Cal ISO Total Output Gap	14,029	12,277	1,752	13,247	11,111	2,136
AS Procurement (excl. replacement)			2,264			2,381
AS Procurement (incl. replacement)			4,153			3,542
Cal ISO Undispatched AS			2,844			2,633

Sources: Ancillary services data from Cal ISO website.
(A), (B), (D), (E): CEMS data, adjusted for Daylight Savings Time. The calculation uses NP-15 prices for Northern zones and SP-15 prices for Southern zones to identify high-priced hours.
(C): (A) – (B).(F): (D) – (E)

The hours covered in Table 13 also included a number of hours with high real-time prices that were not stage 1 (or higher) emergencies. The output gap for these hours has also been calculated and is reported in Table 14 (column F). It can be seen that the calculated output gap is somewhat larger in the non-emergency hours than in the emergency hours, particularly for Mirant. It should be kept in mind, however, that Mirant was likely to be instructed to exceed the

Delta Dispatch limits during emergencies, but would be subject to these restrictions absent an emergency, thus creating an apparent output gap, during high priced non-emergency hours.

It is also useful to compare these "output gaps" to the output of generation presumably lacking an incentive to strategically "withhold." It is seen that the output gap on Southern California Edison's Mohave units during June 2000 was similar in proportion to the output gap on the units alleged to be exercising market power. While the Mohave units had a combined nominal capacity of 1,580 MW and the peak output of the Mohave units during June 2000 was 1,550 MW, the average output during hours in which the Cal ISO real-time price exceeded $120/MWh was only 1,312 MW, and output averaged only 1,301 MW during the non-ramping hours in which the real-time price exceeded $120/MWh. Since the Mohave units were base load coal units with low incremental costs, there was less reason for these to be off line or ramping up and down and they were less likely to be providing reserves than was the case for the gas-fired units analyzed by Joskow and Kahn. Table 15 shows same kind of "output gap" on Mohave, despite the fact that Southern California Edison was a net buyer.

Table 15
Mohave Output, June 2000 (MW)

Average Output	All Hours			Online Hours		
	Mohave 1	**Mohave 2**	**Total**	**Mohave 1**	**Mohave 2**	**Total**
All Hours	642	686	1,329	684	686	1,370
Price >$89	648	688	1,336	651	688	1,339
Price >$120	623	689	1,312	623	689	1,312
Non-Ramping Hours	609	692	1,301	609	692	1,301
Capacity	790	790	1,580	790	790	1,580
Hours on line				676	720	1,396
Max Output	791	784	1,550	791	784	1,550

Source: Output data taken from the CEMS database
Capacity Data taken from Inventory of Electric Utility Power Plants in the United States 1999, September 2000.

In fact, the 18 percent "output gap" for on-line Mohave capacity during high-priced non-ramping hours (1301/1580) exceeds the similar "output gap" on the units of the non-utility generators in Tables 13 and 14.

These sensitivity analyses of the Joskow-Kahn withholding study show that the output gap is much smaller if calculated for on-line units during hours of sustained high prices (non-ramping hours). Moreover, the Joskow-Kahn methodology finds much the same level of output gap during emergency hours in which it is known there was a shortage of capacity at any price as during high-priced non-emergency hours. Overall, the Joskow-Kahn analysis provides no evidence that strategic withholding occurred but strategic withholding cannot be ruled out.

C. Reynolds

1. Overview

Dr. Robert Reynolds subsequently developed a withholding analysis based on confidential data that explicitly attempted to account for some of the limitations of the Joskow-Kahn withholding studies.[71] Dr. Reynolds' analysis was subsequently made public by FERC at the request of various California entities. Dr. Reynolds analyzed output over the period May 2000 through June 19, 2001, taking account of unit on and off status; capacity scheduled hour-ahead to provide reserves or regulation; capacity dispatched down by the Cal ISO (possibly reflecting intra-zonal congestion); unit deratings in a Cal ISO database; unit ramp rates; excluded from his analysis the CTs and GTs subject to operating hour limits; and based his analysis on real-time hourly zonal prices.

Dr. Reynolds' analysis of withholding is a step forward in assessing claims of the exercise of market power in that it starts to focus on the right problem and in many respects takes account of the limitations of prior studies. Nevertheless, rather than providing evidence of a material exercise of market power, his analysis provides an indication that the exercise of market power could not be an important factor in accounting for high prices, as his "evidence" of bad behavior has a much more direct explanation in operational or regulatory factors not adequately accounted for in his withholding analysis.

These factors fall into two basic categories. The first category are the factors that cause Dr. Reynolds' calculation of incremental cost to understate actual incremental generation costs.

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71 Robert Reynolds, Prepared Testimony, Docket No. EL00-95-000, etc., February 27, 2003.

Amount these factors are understated NOx allowance costs, understated gas costs, understated variable O&M costs at high operating levels, omitted or understated credit costs, and no allowance for the impact of the California market design on supply costs. The second category are the omitted or misstated operating constraints that would cause him to misidentify capacity as withheld if his incremental cost calculation were accurate. These factors include his failure to correctly account for environmental constraints, particularly Delta Dispatch, his simplified treatment of ramping constraints, overstated effective capacity due to his failure to account for operating conditions (testing, tides and cooling system performance), failure to take account of interval-by-interval dispatch instructions, incomplete accounting for intra-zonal congestion, and failure to account for Cal ISO dispatch decisions during shortage conditions. These are not minor defects. The result is that Dr. Reynolds' analysis identifies large amounts of strategic "withholding" during periods in which it can be plainly shown that there was no "withholding" of output and no behavior needing explanation by theories regarding the exercise of market power.

The impact of these limitations of his analysis are illustrated in Table 16, which classifies the strategic "withholding" identified by Dr. Reynolds during June 2000 according to the real-time price for that hour. Table 16 shows that most of the "withholding" identified by Dr. Reynolds actually occurred during hours of relatively low prices. In fact, over 68 percent of the "withholding" occurred in hours with real-time prices less than $100/MWh. In addition, there was far more "withholding" in MW per hour during hours with low prices ($60-$100/MW) than high prices.

Table 16
Reynolds' Estimate of Withholding by Price Level, June 2000 (MW)

Real-Time Price Range	Amount of Withholding	Average Withholding by Hour
< 60	46,906	287.47
60 to 80	205,779	2,037.82
80 to 100	127,505	1,990.77
100 to 120	60,116	1,710.23
120 to 200	47,954	1,568.75
200 to 500	34,458	1,222.21
>500	29,444	524.65
Total	**552,162**	**1,150.34**

Source: Table 4 p.28 Scott M. Harvey and William W. Hogan, Prepared Answering Testimony, FERC Docket EL00-95-075 March 20, 2003.

The data showing that most of the alleged withholding took place during low price hours is inconsistent with the theories on which claims of the exercise of market power are based. These sellers have market shares of only 1 or 2 percent overall and 2 to 4 percent of thermal generation in WSCC, so the claims that market power was exercised rest on an assertion that these sellers possessed market power during high load hours when fewer alternatives were available.[72] How then can there be substantial strategic withholding during the low priced hours when generation within the Cal ISO control area had to compete with many other sources of supply throughout the WSCC? The large amount of "withholding" in low-priced hours is consistent, however, with Dr. Reynolds having understated incremental costs and thus finding "withholding" more or less all of the time. It is also consistent with his having omitted many operating constraints such as Delta Dispatch, that are likely to limit output during low load conditions, as well as during high-priced hours.

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[72] The internal inconsistencies in Joskow-Kahn's analysis of the incentive to withhold capacity have been discussed elsewhere. The slope of the supply curve they assume for the rest of the market is steeper than the supply curve of the individual firm whose incentives they analyze. This implies that the firm with these withholding incentives would control more than half of the capacity on the margin in the WSCC, while California generators whose output is analyzed by Joskow-Kahn and Reynolds, actually accounted for 2-4 percent of WSCC thermal generation and less than 10 percent of WSCC gas-fired generation, see Scott M. Harvey and William W. Hogan, "Further Analysis of the Exercise of Market Power in California Electricity Market," November 21, 2001 (hereafter Harvey-Hogan November 2001).

In subsections 2 to 6 below, these conceptual limitations are discussed in greater detail; while subsection 7 revisits his empirical findings.

2. Delta Dispatch

The first of the operational and regulatory limitations that account for the “withholding” identified by Dr. Reynolds are the Delta Dispatch restrictions. The case of the Delta Dispatch rules is instructive as their importance had been pointed out long before Dr. Reynolds undertook his analysis.[73] Dr. Reynolds discusses the impact of the sequencing rules that were indeed a component of the Delta Dispatch restrictions, but he omits the most important Delta Dispatch limitation from his analysis.[74] This limitation is that the Pittsburg 1-6 and Contra Costs 6 and 7 units can only operate above the 86 degree temperature level for outlet water if the ISO specifically instructs Mirant to exceed the 86 degree line in order to address specified system conditions: transmission constraints; RMR instructions to meet local demand; or a Cal ISO state of emergency. The units cannot be dispatched above 86 degrees by the ISO merely because Mirant has submitted a low bid nor is Mirant permitted to operate these units above the 86 degree line to support a bilateral schedule. The effect of the 86 degree temperature limit varied from day to day based on water temperature and unit conditions but appears to have generally ranged between 100-140 MW for the Contra Costa units, 100-200 MW for Pittsburg 5, and 50-100 MW for Pittsburg 1-4. Between May 1 and July 15 each year the dispatch of these units is determined almost entirely by the instructions of the Cal ISO RMR desk. The vast bulk of the “withholding” that Dr. Reynolds identifies on the Mirant units over the period May 1-July 15 2000 and May 1 to June 30, 2001 was found on the units subject to the Delta Dispatch limitations and arose not from discretionary behavior of Mirant, but was instead mandated by environmental permit conditions.

3. Variable Operating Costs

Dr. Reynolds bases his withholding analysis on his assessments of SCAQMD NOx allowance costs during the summer of 2000 and early 2001 that are well below data based on arm’s-length

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[73] Harvey-Hogan April 2001, p. 22; Harvey-Hogan December 2001, p. 36; Harvey-Hogan July 2002, pp. 33-34.

transaction prices.[75] This consideration does not impact his analysis of withholding by the Mirant units, which are located outside SCAQMD in Northern California, but it does impact his assessment of withholding by generators in Southern California.

Dr. Reynolds' calculation of gas costs is based on the *Gas Daily* index price for the SoCal Border or PG&E city gates. These data tend to understate gas costs for two reasons. First, Dr. Reynolds does not include intrastate pipeline tariff and taxes ranging from $.28 to $.46/mmBtu. Second, the gas price index is a reasonable measure of average gas acquisition costs in the day-ahead gas market but it does not necessarily always accurately measure the incremental gas costs that would have influenced power bidding. The *Gas Daily* data is an index that represents the average transaction price, not where the market closed, and it also does not reflect how the price may have changed between day-ahead and real time. This was generally not an issue during summer months but was important during the winter when the gas pipeline system was constrained and there was considerable short-term gas price volatility. These differences between index and closing prices and day-ahead and real-time prices could reasonably be assumed to average out over time, but it is necessary to recognize that such errors in measuring the gas costs will sometimes cause uneconomic capacity to appear to be withheld or sometimes cause economic capacity to appear to operate at a loss on a day-to-day basis.[76] Dr. Reynolds, however, only tabulates capacity that appears to be economic but does not operate. With no offset in his methodology for the dispatch of apparently uneconomic capacity when his measure of gas costs overstates gas costs, his errors in measuring gas costs on a day-to-day basis translate into "withholding," even if the error in measurement of gas prices averages out over time.

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74 Reynolds, pp. 42-43. The sequencing rules required that these units be ramped up above minimum load in a particular sequence.

75 Scott M. Harvey and William W. Hogan Prepared Direct Testimony, Docket EL00-95-075, March 3, 2003 (hereafter Harvey-Hogan March 3, 2003), Table 45. Dr. Reynolds assumes that the NOx price that falls to $7.50 in January, 2001, which was not the case. Dr. Reynolds states that "[i]n February 2001, these plants were given the option to pay a fixed mitigation fee of $7.50 per lb of NOx instead of participating in the RTC market," Reynolds, p. 37, lines 6-8. This is incomplete and inaccurate. Power generators had to pay $7.50/lb. and give up an allowance in the future and future allowance prices were also high. Consider an analogy. Suppose one said, you can have a barrel of gasoline today for $7.50 if you pay back a barrel in 2 years. Would the availability of such an offer indicate that the value of gasoline is $7.50/barrel today? Of course not.

4. Overstated Effective Capacity

Dr. Reynolds' withholding analysis assumes that any capacity that he has not identified as unavailable due to an outage in a Cal ISO database or on reserve shut-down was available and that it was withheld to the extent the capacity is not reflected in net output. This methodology inevitably characterizes capacity as withheld when it is simply not available for other reasons or the units' performance varied from the ideal. Dr. Reynolds' methodology attempts to account for capacity that is not available due to outages but does not account for capacity that is unavailable due to tests, low tides, air temperature, condenser condition, station load, etc., factors that are not always reflected in outages or deratings.

Dr. Reynolds' analysis also identifies undispatched capacity on units coming on-line and not yet at full operating pressure as well as capacity on units ramping down to go off-line for forced or maintenance outages as "withheld." In Dr. Reynolds' model every start-up event results in the calculation of a large amount of withheld capacity because units just coming on-line cannot ramp up at the rates assumed by Dr. Reynolds. As a result, Dr. Reynolds' methodology identifies large amounts of "withholding" on units coming on-line or going off-line.[77] Dr. Reynolds' analysis of withholding by Mirant includes the capacity of units that were off-line (i.e., had zero output before and after),[78] capacity of units ramping down to go off-line,[79] units coming on-line and not yet at full operating pressure,[80] and units struggling to come on or

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[76] While Dr. Reynolds states that he offsets estimated uneconomic operation against estimated withholding there is something wrong with his methodology. His data include 307,553 MW generated by gas-fired generation during zero priced hours during June 2000 yet he finds only 2,549 MW of this output to be uneconomic.

[77] See Harvey-Hogan Prepared Answering Testimony, Docket EL00-95-075, March 20, 2003 (hereafter Harvey-Hogan March 20, 2003), Table M-1.

[78] E.g., Contra Costa 6 on February 18, 2001; Contra Costa 7 on July 7, 2000; Pittsburg 3 on June 2, 2000; Pittsburg 4 on June 5, 2000; and Pittsburg 6 on July 6, 2000.

[79] E.g., Contra Costa 7 on July 3-4, 2000; Pittsburg 1 on October 30-31; 2000, Pittsburg 2 on July 15, 2000, and October 4-5, 2000; Pittsburg 3 on May 24-25, August 29-30, September 22-23, 2000; Pittsburg 4 on September 8-9, 2000 and February 21-22, 2001; Pittsburg 5 on July 7-8, 2000 and May 15, 2001; Pittsburg 6 on July 5-6 2000 and May 16-17, 2001.

[80] Contra Costa 6, 2000; Contra Costa 7 on October 3-4, 2000 and October 14-15; Pittsburg 1, September 29, 2000, October 31, 2000, November 9, 2000, and February 12, 2001, Pittsburg 2 August 21, 2000; Pittsburg 3 September 4-5, 2000 and March 6-7, 2001; Pittsburg 4, June 12, 2000 and April 1-2, 2001; Pittsburg 5 on December 10 and 21, 2000; Pittsburg 6 July 10-11, 2000; and Pittsburg 7 July 4-5, 2000, July 17, 2000, and February 4, 2001.

stay on-line with near zero output.[81] Other factors not taken into account by his methodology include: outages not recorded by Cal ISO; delays in reporting real-time deratings; and delays in getting bids or schedules into the Cal ISO system.

5. Ramping Constraints and Dispatch Instructions

While Dr. Reynolds attempted to account for ramp constraints in his analysis of withholding, his methodology has several conceptual limitations that cause him to identify "withholding" when none occurred. In particular, Dr. Reynolds' analysis does not consider when a unit received an INC instruction from the Cal ISO; does not consider if the price was high throughout the hour or only rose partway through the hour;[82] does not consider if the price was falling during the hour; assumes that the same ramp rate for normal operation is applicable when a unit is coming on-line; and assumes that the ramp rate is never limited by operating problems.

Because he does not consider the interval prices and dispatch instructions during the hour, but only the final ex post hourly price, his model tends to have units ramping up sooner and more steadily than would actually be the case in hours in which the price was initially low (and even zero) in the initial intervals of the hour or was low (and sometimes zero) at the end of the hour. During hours in which the dispatch price began low or ended low, competitive generators would not have been ramping up at maximum throughout the hour as assumed by Dr. Reynolds. Instead, generators that were following the dispatch instructions would have been ramping down, not up, during parts of these hours, reducing their average hourly output. These difficulties are compounded by the fact that Dr. Reynolds does not reset his ramp limits based on the units' actual output during the period, but instead bases each hours ramp limit on the hypothetical rather than actual operating level during the period hour. This means that errors in accounting for when capacity was available or when prices rose can lead to errors in available capacity that can persist for several hours.

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81 Pittsburg 1 November 1-2, 2000; Pittsburg 3, November 4-5, 2000; Pittsburg 4, June 12, 2000, Pittsburg 6 on October 30, 2000; and Pittsburg 7 on April 16, 2001.

82 Reynolds, p. 73 lines 20-23, recognizes dispatch prices vary by interval.

6. Shortages and Intrazonal Congestion

Dr. Reynolds' model has the potential to misidentify units as withholding when they were not dispatched for reliability reasons. Many of the high priced hours during the summer of 2000 were hours of reserve shortage. The Cal ISO was short of capacity during these hours, the marginal source of capacity was imports, and the equilibrium market price was above the price cap price, because there was a shortage of capacity at the price cap. During this period, capacity was short in California and which capacity was dispatched for energy and which capacity, in practice, provided reserves (whether or not it was paid to provide reserves) did not impact the market price and reflected the reliability decisions of the Cal ISO operators, not withholding by suppliers.[83]

Dr. Reynolds' analysis accounts for generation that was dispatched down by the Cal ISO because of intrazonal congestion, but does not account for generation that was not dispatched up by the Cal ISO because of intra-zonal congestion. We doubt that such intrazonal congestion was material during high priced hours during crisis period, but it could well have been material during the many low priced hours included in Dr. Reynolds analysis and may have contributed to the large amount of "withholding" he identified during low priced hours.

7. Pittsburg 7 and Potrero 3

These indications that Dr. Reynolds' methodology potentially overstate the actual level of economic withholding do not, however, demonstrate that he has not identified material strategic "withholding" during the high priced hours he examined. This section discusses a detailed analysis of these claims for June 2000, focusing on the high price hours in which his misstatement of incremental costs is least likely to skew the calculation of withheld capacity. This analysis shows that Dr. Reynolds' identification of withholding by Mirant arises from his 1) misstatement of Delta Dispatch restrictions, 2) exaggerated ramp rates, 3) failure to account for real-time operating conditions.

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83 Recognition of this reality caused the NYISO to file tariff changes providing that generation that is backed down during reserve shortage conditions will be paid its opportunity cost (the difference between the price at its location and its offer price), even if prior to the operating hour the capacity backed down was not scheduled to provide reserves.

The operation of the Pittsburg 7 and Potrero 3 units was not subject to the Delta dispatch restrictions. It is therefore striking to observe that while Dr. Reynolds claims to find an enormous amount of withholding on the units that were subject to the Delta Dispatch restrictions (which restrictions he ignores), he identifies very little "withholding" on Potrero 3 and Pittsburg 7. His withholding calculation identifies 4,774 MWh of withholding on Pittsburg 7 and 5,648.06 MWh on Potrero 3 during June 2000, or about 25 MWh per hour,[84] compared to 190,081 MWh on the 8 units subject to Delta Dispatch.

Moreover, if the remaining withholding claims on the units not restricted by Delta Dispatch are reviewed, they are all attributable to the simplifications in Dr. Reynolds analysis. 1,611 MW of the "withholding" on Pittsburgh 7 occurred during hour 7 in the morning when prices are low and unit ramp rates sometimes lag that assumed by Dr. Reynolds. On June 12 he identifies 145MW of withholding when the unit was just coming back on line and had not reached full operating pressure. He identifies "withholding" on June 8 that actually reflected testing that was going on at the unit. The remaining "withholding" during June was on Sunday June 18 when the unit was coming back on line after repairs and had not yet reached full operating pressure, and on Saturday and Sunday June 24 and 25 during hours with low interval prices, including a number of zero prices.[85]

Dr. Reynolds also claims to have identified 5,648.06 MWh of strategic withholding on Potrero 3 during June 2000. The importance of ramp constraints and other factors unrelated to strategic withholding in accounting for the "withholding" identified by Dr. Reynolds is illustrated by Table 17 which shows that 70 percent of the "withheld" capacity was withheld in hours with prices less than $100. This is not consistent with the theory of withholding during hours with few alternatives but is consistent with understated incremental costs and omitted or misstated operating constraints such as ramp limits.

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[84] It should be noted that Dr. Reynolds uses "peak hours" to refer to HE 7-22, all seven days of the week and his "withholding" data are calculated for those days.

[85] For a detailed discussion of output during these hours, see Harvey-Hogan Prepared Answering Testimony, March 20, 2003, pp 32-37.

Table 17
"Withholding" on Potrero 3 by Price Level, June 2000 Peak Hours

NP-15 Real-Time Price	Number of Hours	Amount of Withholding	Average Withholding by Hour
< 60	155	432.04	2.79
60 to 80	105	2270.61	21.62
80 to 100	66	1261.74	19.12
100 to 120	37	442.30	11.95
120 to 200	30	529.14	17.64
200 to 500	27	299.66	11.10
>500	60	412.57	6.88
Total	480	5648.06	11.77

Source: Table 10 p37 Scott M. Harvey and William W. Hogan, Prepared Answering Testimony, FERC Docket EL00-95-075 March 20, 2003.

During June 2000 there were 42 hours in which Dr. Reynolds identified "withholding" of 10 MWh or more on Potrero 3 and the real-time price exceeded $100/MWh. Each of these hours was reviewed to assess whether the output level likely reflected strategic withholding or instead appeared to reflect the effects of tides, ramp rate limits, and operating problems, and the normal operation of a competitive market.[86] Table 18 summarizes the factors that appear to account for the difference between the actual output of Potrero 3 and that estimated by Dr. Reynolds. Most relate to limitations arising from the units' cooling systems (Bay water and cooled hydrogen gas).

[86] For a detailed discussion of Potrero 3 output during these hours, see Harvey-Hogan March 20, 2003, pp. 37-43.

Table 18
Potrero 3 Output Limitations

Hour	Date	
7, 8	June 15	Low tide, back pressure limits output
15, 16	June 20	Unit coming back online
11, 12, 13	June 21	High condenser back pressure
21, 22	June 22	Low price intervals, including zero, during hours
22	June 23	Condenser full of sea life; unit being taken down to minimum load for cleaning
22	June 24	Cooling gas temperatures at limit
15, 16	June 25	Cooling gas temperatures at limit
8	June 26	Zero price during first four intervals of prior hour, cold gas temperature limits
22	June 26	Output reduced for condenser tunnel cleaning
Many	June 28	Ramping up from minimum load for condenser cleaning early in morning and cooling gas temperature at limit later in day
9-20, 22	June 29	Derating due to heater drip pump and mussels fouling intake tunnels
10, 11	June 30	Ramping up from tunnel cleaning

Source: Scott M. Harvey and William W. Hogan, Prepared Answering Testimony, FERC Docket EL00-95-075 March 20, 2003 pp 39-43.

Overall, it was found that all of the instances of "withholding" by Potrero 3 identified by Dr. Reynolds appear to be instances of limitations imposed by real-world operating constraints that are omitted from Dr. Reynolds' analysis.

There are also small positive amounts of "withholding" identified by Dr. Reynolds during almost every hour on Potrero 3 during the high priced hours (i.e., less than 10 MW). These small differences likely exist because units cannot consistently operate at their nominal net generation capacities, even when dispatched to the top. These small gaps generally exist when Potrero 3 was operating close to capacity and did not quite manage to generate at its nominal capacity rate throughout the hour. It is also noteworthy that during many of these hours Potrero 3 had day-ahead schedules for its nominal capacity and therefore Mirant was a buyer at the real-time price to the extent that Potrero 3 was not able to operate at its nominal capacity throughout the hour.[87]

[87] Harvey-Hogan March 20, 2003, pp. 45-56, also contains an hour-by-hour evaluation of Dr. Reynolds' withholding analysis for March 2001.

Even if Dr. Reynolds' claims of "withholding" by Potrero 3 and Pittsburg 7 were taken at face value, the pattern of the claimed withholding would not be consistent with strategic withholding intended to influence price. The average ex post price during the hours analyzed by Dr. Reynolds for June 2000 was $161.59/MWh, while the weighted average price during the hours during which Dr. Reynolds identified withholding on Pittsburg 7 and Potrero 3 was only $110.32/MWh. Moreover, of the 125 hours during June 2000 during which Dr. Reynolds identified withholding of 10 MW or more by Pittsburg 7 or Potrero 3, the price exceeded $100/MWh in only 42 hours. It is remarkable that despite the claims of market power exercised through withholding during very tight market conditions, the "withholding" claims of Dr. Reynolds, even if taken at face value, imply that the "withholding" occurred mostly during relatively low-priced hours but in these hours the alleged withholders would have unambiguously been competing with generation throughout the WSCC and faced an elastic residual demand curve that would have made withholding unprofitable.

IV. PHYSICAL WITHHOLDING

Market power could in principle be exercised either by economically withholding capacity from the market by offering the capacity at high prices or by physically withholding capacity by keeping it off-line or declaring it unavailable.[88] On the other hand, generating capacity will suffer forced outages or deratings even in a competitive market, so unavailable capacity is not necessarily physically withheld. Joskow-Kahn suggest that the difference between undispatched capacity and undispatched ancillary service capacity in their Table 8 is too large to be consistent with normal historical forced outage rates.[89] This view is mistaken. There is in fact no evidence that outage rates for California NUG generation were unusually high during the 2000-2001 period and some evidence that outage rates were on the contrary unusually low.

Joskow and Kahn assert that outages during the high priced periods could have been attributable only to forced outages or physical withholding. This view is incorrect. First, units are off-line in summer months both as a result of forced outages and maintenance outages, and

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[88] Joskow-Kahn 2002, p. 26.

[89] Joskow-Kahn 2002, pp. 26-29. Earlier Joskow-Kahn papers suggested other indications of physical withholding on which we have commented elsewhere, see Harvey-Hogan December 2001, pp. 73-78.

Table 6 above showed that this was true under utility ownership as well. Second, while generation owners and the system operator attempt to schedule planned overhauls to be completed prior to the summer months, it is not always possible to complete all of this work prior to June. Mirant's Pittsburg 6 was unavailable from March 3, 2000 to June 23, 2000 as a result of a planed outage for installation of low NOx burners that was required for the continued operation of the unit.[90] Comprehensive data are not available, but it appears that one or two other units were unavailable during the early part of June 2000 for the installation of low NOx burners.

The third factor overlooked by Joskow and Kahn in identifying reasons units might be off-line during a high priced hour is particularly important. This is the unit commitment decision. It is important to understand that the high priced hours analyzed by Joskow-Kahn in their Table 8 and in Tables 13 and 14 above are just that, high priced hours. The hours did not necessarily fall on a high priced day or period of a day. The large steam units that were off-line during these hours require many hours to come on line and could not physically respond to unanticipated high prices. Moreover, given the high costs of starting up an off-line unit or of keeping a unit on-line at minimum load, it would not necessarily have been economic to use these units to meet load in these individual high priced hours even had the high prices been perfectly anticipated. It has been shown in earlier papers that based on actual day-ahead PX prices, it would not have been economic for a number of units to have been on-line during some of these "high-priced" hours in June 2000.[91]

Joskow and Kahn characterize this view as arguing that "all units which ran, or 'should have run, must be profitable ex post."[92] This view is mistaken. The unit commitment decision in the California market was based on expected prices.[93] Given imperfect foresight, this necessarily

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90 This outage was prolonged by serious problems that were identified during the installation of the low NOx burner. In addition, Contra Costa 6 was offline from November 29, 2000 to February 19, 2001; Pittsburg 5 was off-line from March 17,2001 to May 14, 2001; and Contra Costa 7 was off-line from May 5, 2001 to June 19, 2001 for the installation of low NOx burners or SCRs. It should be kept in mind that the State of California did not release Mirant or other suppliers from the environmental requirements that mandated these outages.

91 Harvey-Hogan April 2001, pp. 25-33, and Harvey-Hogan December 2001, pp. 3-26.

92 Joskow Kahn September 2002, p. 28 footnote 33, and Joskow-Kahn February 2002, p. 32.

93 Except in the case of RMR units committed by the Cal ISO to manage intra-zonal congestion in various load pockets. One change between 1999 and 2000 was that SCE had expanded the transmission grid obviating the need for substantial RMR capacity in the LA basin so much less capacity was being committed by the Cal ISO

implies units will sometimes have been committed yet it will turn out after the fact that their operation was not economic. Conversely, however, this same imperfect foresight implies that units will sometimes not have been committed yet it will turn out after the fact that their operation would have been economic. The output gaps calculated by Joskow-Kahn in Tables 7 and 8 assume that all capacity that would have been economic to operate at actual prices was committed, and in addition substantial capacity that would not have been economic to operate should also have been committed. This view is unsupportable. While the presence of uncertainty regarding real-time prices introduces ambiguity in distinguishing mistakes from profit maximizing decisions, it is a useful reality check on any such withholding analysis to assess whether the operation of the "withheld" units would actually have been profitable had the operator perfectly foreseen real-time prices. This is a symmetric assumption that all capacity that after the fact turned out to be economic would have been on line, and that all capacity that turned out after the fact to be uneconomic would not have been on line. A claim that economic or physical withholding occurred because units that actually would have been uneconomic to operate did not operate is not credible.[94]

Table 19 shows that the amount of capacity that was on line during the period of high prices was not lower but was instead much higher than under past utility operation of these same plants.[95] These data do not, however, demonstrate that there was no physical withholding, because these units were often off-line under utility ownership not due to outages but simply because their operation was not economic due to the start-up and no-load costs discussed above. Thus, it is possible that although more capacity was kept on line on these NUG units for more hours than ever before, it might have been possible to have had still more capacity on line but for physical withholding.

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under RMR contracts than in prior years. Thus expected prices had to be higher than in prior years in order to make it economic to commit the former RMR units.

94 It is noteworthy that PJM, NYISO and ISO-NE have all operated day-ahead unit markets and commitment processes that evaluate the commitment of generation based on start-up costs, minimum load costs as well as energy costs, over the 24 hours of the operating day. It was an element of the ideological commitment to "market separation" of those responsible for the Cal ISO market design that no such process operated in California. This was idiotic, but the idiocy did not arise from suppliers in the California market.

95 This comparison is limited to the period October 1997 to date because this is the period for which the EPA CEMS data are available on-line. It has not been possible to obtain CEMS data prior to October 1997 from the EPA.

Table 19
Average Hourly Capacity On-Line –
Selected California NUG Units, 1997-2001 (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Non-Utility (NUG) Units											
1997	-	-	-	-	-	-	-	-	-	7,647	5,713	6,293
1998	6,634	5,743	5,812	5,046	4,326	5,928	9,625	11,679	9,962	7,136	6,556	6,536
1999	6,981	6,582	5,710	6,380	5,688	7,254	8,566	8,709	7,774	11,591	7,437	6,828
2000	6,604	6,732	5,938	5,846	9,013	12,401	12,717	13,627	12,376	10,708	9,292	9,999
2001	10,742	10,729	10,537	10,197	10,116	11,535	12,518	13,402	11,730	9,948	8,114	9,240

Source: EPA CEMS Data. Capacity values come from EIA form 806, EIA Inventory of Nonutility Electric Power Plants in the United States 1999, and EIA Inventory of Utility Electric Power Plants in the United States 1999.

Note 1: This table reports the average hourly capacity, by month, of the generators that were online in the particular hour. Many units do not report CEMS data, and therefore must be excluded from this table. Units excluded due to lack of data: Alnor, Brawley, Coachella, Downieville, Ellwood, Glenarm, Kearny, Kern, Kings Beach, Long Beach, McClellan, McClure, Mountainview, North Island, Oakland, Pebbly Beach, Portola, Redding Power, Rockwood, Walnut.
Units included in this table are: Alamitos, Contra Costa, Coolwater, El Segundo, Encina, Etiwanda, Huntington Beach, Mandalay, Morro Bay, Moss Landing, Ormond Beach, Pittsburg, Potrero, Redondo Beach, Riverside, South Bay.

The FERC staff investigated the outages of the California non-utility generators in 2001 and found no evidence of physical withholding.[96] The CPUC issued a report in 2002 that claimed to show evidence of physical withholding,[97] but its methodology was challenged by the Cal ISO[98] as well as the generators,[99]and FERC staff concluded that the allegations were not supported and most of the capacity alleged to have been withheld actually was not available for other reasons.[100]

Joskow-Kahn suggest that evidence of physical withholding would be provided by a correlation between high forward sales (and thus a lack of benefit from high spot prices) and high unit availability and observe that Duke is reputed to have sold 90 percent of its output forward and also had relatively high availability for its units.[101] Joskow-Kahn do not provide comparable outage statistics for any other generators, nor do they analyze forward sales levels

96 FERC Office of the General Counsel Market Oversight & Enforcement and Office of Markets, Tariffs and Rates, Division of Energy Markets, Report on Plant Outages in the State of California, February 1, 2001.

97 CPUC, "Investigative Report on Wholesale Electric Generation," September 17, 2002.

98 California ISO, "Commentary by the California Independent System Operator Corporation on the CPUC Staff Investigative Report on Wholesale Electric Generation, released September 17, 2002 and Supplement, January 30, 2003.

99 Mirant, Letter to Joseph Dunn from Zack Starbird, September 26, 2002.

100 See Staff Review of California Public Utility Commission's September 17, 2002 Investigative Report on Wholesale Electric Generation, March 26, 2003.

101 Joskow-Kahn July 2001, pp. 25-26.

across generators.[102] The company with the highest level of forward sales, however, was AES which sold all of its output forward. AES also described itself as having had unusually high forced outage rates during 2000.[103] The result of the high forced outage rates was that the company became a net buyer and actually lost money on California operations during 2000.[104] Moreover, any such analysis needs to hold constant unit characteristics, as owners of low cost, high capacity, reliable base load units would be willing to enter into higher levels of forward sales than the owners of small, high cost units that rarely run and have high historical outage rates.[105]

In addition to the individual plant investigations undertaken by FERC staff, it is possible to examine the aggregate on-line versus outage performance to see if there is any increase in outage rates during the crisis period. In making claims that forced outages were unusually high during 2000-2001, neither the CPUC, Joskow-Kahn nor BB&W analyzed the historical forced outage data for the divested units. Analysis of this data permits one to make an assessment of whether the outage rates observed for the divested units during the 2000-2001 period were in fact unusually high, given the historical performance and crisis period usage rates for the units.

Historical outage data for the units divested by SCE are not publicly available but Mirant obtained five years of historical outage data from PG&E when it purchased the plants and made these data available for analysis. Review of these historical data suggests that outages were unusually low under Mirant operation during 2000 and 2001 compared to historical outage rates under PG&E ownership and operation. Consider, for example, Pittsburg 1. Over the 5-year period from April 1, 1994 to March 31, 1999 under PG&E ownership and operation Pittsburg 1 had 19 forced outages and 14 maintenance outages or roughly 4 forced outages and 3

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102 The output gap Joskow-Kahn calculates for Duke is lower than the gap they calculate for other companies in part because the output gap Joskow-Kahn calculate for Duke is understated by the use of understated capacities while the output gap calculated for other suppliers is overstated by overstated capacities.

103 See Stu Ryan, AES Pacific, February 1, 2001, Analyst Presentation. While Williams controlled the dispatch of the AES units, the outage status was determined by AES, which had an incentive to make the capacity available. Moreover, Williams had also sold almost of the on-peak output available to it in forward markets and thus appears to have also lacked an incentive to withhold capacity. In fact, Williams was net short on-peak for the months of August through November 2000 as a result of outages. Affidavit of Dennis Elliott, Docket ER99-1722-004, May 2, 2001.

104 AES January 29, 2001, press release re: Annual Earnings, Aesc.com/investor/press/index.html.

105 This pattern can be seen in the Mirant units in Tables 20 and 21.

maintenance outages per year. Between April 1, 1999 and March 31, 2000, this unit had 5 forced outages and 2 maintenance outages. Between May 22, 2000 (when it came back from a maintenance outage) and May 21, 2001 it had 11 forced outages and 1 maintenance outage. If this data were analyzed solely with regard to outages per year of calendar time, the rate of outage would appear higher during 2000 than in prior years. Such a statistic would not capture, however, the fact that during the 5 years from 1994 to 1999 Pittsburg 1 was off-line in reserve shutdown for 26,856 hours (i.e., more than 3 years of outages), off line for forced and maintenance outages for another 8,966 hours (more than another year of outages) and only on line for 8,233 hours over the 5-year period, about 1,645 hours per year.[106]

Between May 22, 2000 and May 21, 2001, however, Pittsburg 1 was off line for economics (reserve shutdown) for only 602 hours, and on-line for 5,267 hours, not far from the number of hours it was on-line over the 5-year period from 1994-1999. It therefore had a forced outage every roughly 479 on-line hours during 2000-2001, compared to 1 every 433 on-line hours over the 1994-1999 period. Further, Table 20 shows that Pittsburg 1 had an outage of some sort every 439 on-line hours during 2000-2001, compared to 1 every 175 hours over the 1999-2000 period. In addition, Table 20 shows that Pittsburg generated 21,148 MW per outage over the 5 years under PG&E ownership and 40,961 MW per outage during 2000-2001 under Mirant ownership.

Table 20 provides similar data for each of the Mirant steam units and shows that all of these units had similar or lower outage rates per hour on-line or per MW generated during the 2000-2001 period than under PG&E ownership. The difference in use is particularly large for Pittsburg 1-4, which rarely ran under PG&E ownership.

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[106] These figures are calculated from PG&E outage data for the 1994-1999 period and from Mirant outage data since April 1999. Some hours (particularly in the 1994-1999 period) were not identified as shutdowns but the output data show zero output. These have been classified as reserve shutdown hours.

Table 20
PG&E and Mirant Outage Rates

Time Period	Forced Outages [1]	Maintenance Outages [1,2]	Total Non-Reserve Shutdown Outages per Year	# of Hours Online	Hours Online per Forced Outage	Hours Online per Non-RReserve Shutdown Outage	Total MW Generated	Total MW per Non-Reserve Shutdown Outage
Contra Costa 6								
5/22/00 through 5/21/01 Mirant	4	2	6	6,578	1,644	1,096	1,509,485	251,581
4/1/99 through 3/31/00 Mirant	2	2	4	6,738	3,369	1,684	1,201,089	300,272
4/1/94 through 3/31/99 PG&E	28	15	9	23,525	840	406	4,589,256	106,727
Contra Costa 7								
5/22/00 through 5/21/01 Mirant	4	3	7	7,620	1,905	1,089	1,911,938	273,134
4/1/99 through 3/31/00 Mirant	2	2	4	6,970	3,485	1,743	1,215,373	303,843
4/1/94 through 3/31/99 PG&E	42	25	13	24,638	587	268	4,740,845	70,759
Pittsburg 1								
5/22/00 through 5/21/01 Mirant	11	1	12	5,267	479	439	491,534	40,961
4/1/99 through 3/31/00 Mirant	5	2	7	2,748	550	393	155,871	22,267
4/1/94 through 3/31/99 PG&E	19	14	7	8,226	433	175	697,898	21,148
Pittsburg 2								
5/22/00 through 5/21/01 Mirant	13	1	14	5,588	430	399	533,396	38,100
4/1/99 through 3/31/00 Mirant	3	3	6	3,938	1,313	656	223,398	37,233
4/1/94 through 3/31/99 PG&E	19	16	7	9,596	505	188	837,095	23,917
Pittsburg 3								
5/22/00 through 5/21/01 Mirant	13	-	13	4,293	330	330	424,372	32,644
4/1/99 through 3/31/00 Mirant	2	2	4	807	404	202	48,569	12,142
4/1/94 through 3/31/99 PG&E	30	10	8	7,487	250	150	683,545	17,089
Pittsburg 4								
5/22/00 through 5/21/01 Mirant	4	5	9	5,965	1,491	663	621,024	69,003
4/1/99 through 3/31/00 Mirant	3	1	4	1,343	448	336	88,628	22,157
4/1/94 through 3/31/99 PG&E	26	15	8	7,123	274	127	656,483	16,012
Pittsburg 5								
5/22/00 through 5/21/01 Mirant	3	5	8	6,920	2,307	865	1,572,054	196,507
4/1/99 through 3/31/00 Mirant	2	2	4	4,896	2,448	1,224	652,864	163,216
4/1/94 through 3/31/99 PG&E	35	15	10	24,144	690	371	3,825,312	76,506
Pittsburg 6								
5/22/00 through 5/21/01 Mirant	3	4	7	7,506	2,502	1,072	1,896,931	270,990
4/1/99 through 3/31/00 Mirant	3	3	6	4,836	1,612	806	631,831	105,305
4/1/94 through 3/31/99 PG&E	21	26	9	29,841	1,421	409	4,702,918	100,062
Pittsburg 7								
5/22/00 through 5/21/01 Mirant	5	7	12	7,829	1,566	652	4,544,488	378,707
4/1/99 through 3/31/00 Mirant	3	1	4	3,957	1,319	989	1,242,792	310,698
4/1/94 through 3/31/99 PG&E	21	19	8	24,479	1,166	415	11,453,226	286,331
Potrero 3								
5/22/00 through 5/21/01 Mirant	3	6	9	6,681	2,227	742	994,864	110,540
4/1/99 through 3/31/00 Mirant	7	5	12	6,180	883	515	783,496	65,291
4/1/94 through 3/31/99 PG&E	16	19	7	32,591	2,037	604	4,174,431	119,269

Notes: (1) The counts of outages by type include any outage that began within the relevant time period. Any outage that starts less than sixty minutes after the previous outage ends has been merged with the previous outage. (2) Maintenance outages include overhauls.
Source: Table 96 p353-354 Scott M. Harvey and William W. Hogan, Prepared Direct Testimony, FERC Docket EL00-95-075 March 3, 2003.

Similar data for the Potrero combustion turbines are portrayed in Table 21 and it can be seen that these units had far more hours on-line and generated far more power per outage during the crisis period than under prior PG&E ownership. In fact, it can be seen that these units generated more power during the crisis period than under the last five years of PG&E ownership combined.

Table 21
Potrero Combustion Turbine Outages, 1994-2001

Time Period	Forced Outages [1]	Maintenance Outages [1,2]	Total Non-Reserve Shutdown Outages per Year	# of Hours Online	Hours Online per Forced Outage	Hours Online per Non-Reserve Shutdown Outage	Total MW Generated	Total MW per Non-Reserve Shutdown Outage
Potrero 4								
5/22/00 through 5/21/01	7	16	23	1,502	215	65	65,493	2,848
4/1/99 through 3/31/00	6	6	12	405	68	34	17,472	1,456
4/1/94 through 3/31/99	39	68	21	1,204	31	7	50,012	467
Potrero 5								
5/22/00 through 5/21/01	6	19	25	1,617	270	65	77,744	3,110
4/1/99 through 3/31/00	6	3	9	490	82	54	19,804	2,200
4/1/94 through 3/31/99	31	66	19	1,558	50	10	59,763	616
Potrero 6								
5/22/00 through 5/21/01	13	15	28	1,639	126	59	86,378	3,085
4/1/99 through 3/31/00	3	9	12	481	160	40	20,703	1,725
4/1/94 through 3/31/99	39	63	20	1,476	38	9	52,825	518

Notes: (1) The counts of outages by type include any outage that began within the relevant time period. Any outage that starts less than sixty minutes after the previous outage ends has been merged with the previous outage. (2) Maintenance outages include overhauls.
Source: Table 19 p.68 Scott M. Harvey and William W. Hogan, Prepared Answering Testimony, FERC Docket EL00-95-075 March 20, 2003.

It should be noted that attaining these performance levels for the Potrero GTs required extraordinary measures by Mirant including the introduction of round-the-clock fuel deliveries (the units are oil-fired), putting in a pipeline to deliver fuel, and extremely high expenditures on third-party repairs and maintenance to keep the units on-line. None of this behavior is consistent with the assertion that withholding was profitable, but rather suggests the reverse – that high prices during the crisis period made it economic for Mirant to incur large costs to keep these units available, resulting in extraordinarily low, not high, outage rates. These comparisons of outages and use under Mirant and PG&E ownership are inconsistent with the assertions that outage rates were inexplicably high under Mirant operation and indicative of physical withholding. The data in fact suggest unusually low outage rates under Mirant operation, given the way the units are used.

These comparisons do not fully control for all of the differences in use between the earlier period and the 2000-2001 period, such as the impact of long periods of operation at very high output levels. In order to further control for these other factors and test the claims that outage rates were unusually high during the 2000-2001 period, a statistical outage model was developed utilizing data on the Mirant units under both PG&E and Mirant ownership. This model is discussed in detail elsewhere.[107] It was found that, controlling for intensity of use based on pre-crisis performance, time between failures should have decreased during the crisis period. However, the estimated time to failure actually increased during the crisis. This suggests lower than normal, rather than higher than normal, outage rates during the crisis period. Overall, from this analysis it appears that the most likely effect of the California crisis on the forced and maintenance outage performance of the Mirant plants is that the plants were on-line much more than would have been expected given the experience before the crisis. After controlling for utilization and other factors, the data provide statistical support for the view that substantial efforts were made to keep the plants running, and there is no statistical evidence seen here that is consistent with any assertions of physical withholding.

V. MARKET POWER ANALYSIS

The Joskow-Kahn, BB&W and Reynolds analyses address a difficult public policy question. The point of the comments above is not that market power never exists, nor that it cannot be detected. The point is that the simplified simulation methodologies employed by Joskow-Kahn, BB&W and others are not capable of identifying the exercise of market power with the precision required. Absent some kind of large offsetting bias, these simulations will likely always find that market power has been exercised, as real prices will always be higher than simulated prices and much higher in shortage conditions. This outcome is virtually guaranteed by analyses based on simulation models that are non-chronological, omit start-up and minimum load costs, omit reserve requirements, omit environmental limits, omit energy limits, do not reflect actual outages and deratings, and make no allowance for the impact of real-time surprises. Additional error can arise if unit capacities are incorrectly specified and the import supply curve misstated and if the simulation does not reflect the actual market rules that determine prices.

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[107] Scott M. Harvey and William W. Hogan, Prepared Direct Testimony, March 3, 2003, pp. 231-248. Scott M. Harvey, William W. Hogan and Todd Schatzki, "A Hazard Rate Analysis of Mirant's Generating Plant Outages in California," January 16-17, 2004.

Similarly, withholding analyses that do not take account of outages and deratings, ramping constraints, environmental limits, unit performance limits, and actual dispatch rules and procedures will inevitably find economic or physical withholding. Additional error can arise if unit capacities are incorrectly specified.

The conclusion of the analysis in this paper, however, is not that it is impossible to reliably detect the exercise of market power in the electric industry. While the factors discussed above render such comparisons of actual and simulated prices inadequate to identify the exercise of market power, direct examination of real-time output for evidence of economic and physical withholding is an appropriate method for identifying the exercise of market power.

The first question to ask in assessing is whether high prices are materially impacted by economic withholding would be to ask whether there was a shortage. That is, was there inadequate capacity available at any price to meet load and provide required ancillary services. System operators generally have a system for tracking the real-time availability of reserves on their system for purpose of compliance with NERC standards and taking remedial action when they become reserve short. By referring to these systems it is straightforward to determine whether a shortage situation in fact existed during high price intervals given the available capacity.[108]

If there was not a physical capacity shortage during an hour, then the next step would be to determine whether economic withholding materially contributed to creating an economic shortage during that hour. This can be assessed by examining the capacity actually offered to the market for dispatch on each unit, accounting for capacity that was not-available due to ancillary reserve requirements, ramping limits, environmental restrictions or because the unit was not on-line, and examining the dispatch instructions and uninstructed output of the units.

While the withholding analyses of Joskow-Kahn and Reynolds failed to account, or failed to properly account, for many operational factors affecting real-time output, the information

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[108] It is important to recognize that during periods in which the system is highly stressed operating reserves may be carried in real-time on different units than the reserves were initially scheduled. This situation is particularly likely to develop if events during the day have required activation of reserves carried on off-line quick-start units. Once these units are started they often cannot be backed down and minimum down times could make it impossible to turn the units off without losing their capacity.

needed to properly account for these factors is readily available to the system operator in well designed electricity markets. The simple reality is that these factors need to be known to the system operator in real-time for the purpose of the least cost dispatch of the transmission system, and the determination of whether a unit's output in a particular dispatch interval was limited by its offer price or by physical operating parameters should be readily observable from the data used in the system operators dispatch and the dispatch instructions themselves (see Table 2).

In PJM and New York the impact of "intra-zonal" and "inter-zonal" congestion is reflected in the LMP prices, the identity of capacity providing reserves or regulation is known to the system operator and accounted for in the dispatch, and the dispatch instructions also account for ramp rates, deratings, and environmental constraints. This means that it is straight-forward to identify those units whose dispatch was limited by their offer price rather than by operational factors. Thus, two parts of the question, whether high prices are due to shortage conditions and whether capacity is being economically withheld should in principle be readily ascertainable from ISO systems. The remaining questions are whether the economic withholding reflects the exercise of market power or merely the high cost of units that are economically withheld from the dispatch and whether high prices were produced by physical withholding.

In addressing the third question of whether offer prices that economically withheld energy during periods in which there was no shortage of capacity reflected the exercise of market power, it is necessary to account for daily, seasonal or annual energy limits, day-ahead and intra-day gas prices and transportation charges as well as balancing penalties, O&M costs, heat rate performance (including air and water temperature driven variations), emission allowance costs, as well as the extra-ordinary costs and outage risks that are sometimes incurred at operating generating units at very high rates. As discussed above, withholding analyses that do not account for these factors will not provide a reliable assessment of economic withholding. While examination of these factors requires effort, this effort is not that difficult for a well functioning market monitoring unit.

The ISO generally will, or at least should, know which units are subject to energy limits and can make allowance for the reality that it is often efficient, and necessary from a reliability standpoint for these units to offer their output at prices in excess of incremental cost. Moreover, in well designed markets such units will generally scheduled to provide reserves and thus will in practice only be dispatched when the system is in a shortage condition and the reason for high prices is readily apparent.

Gas costs can be difficult to accurately monitor during cold spells in the winter when short-term gas supply is limited and gas prices and balancing charges serve to ration gas consumption. During these periods gas prices can be very volatile and intra-day gas prices may be higher or lower than day-ahead gas prices, and the day-ahead index price (which is an average transaction price) can differ materially from the gas prices at the closing of the day-ahead gas scheduling process. This kind of gas price volatility is generally not present during the other seasons, however, and gas prices are unlikely to change radically from day to day during the spring, summer or fall. While there can be a degree of uncertainty in the measurement of variable O&M costs, heat rates and emission allowance costs, these cost are not likely to vary radically from day to day, so sudden changes in offer prices intended to economically withhold output are readily apparent.

Finally, although it may be difficult to accurately measure the high costs associated with very high output on particular units, either arising from increasing outage risk, degraded heat rates, or extra-ordinary operating procedures that are required to reach these output levels, it will be readily apparent if these high offer prices are applied to more than the top of the unit.

Thus, the system operator and market monitor should know which units are energy limited, which units burn gas (and which can and cannot fuel switch) and which units incur emission allowance costs. Moreover, most of these factors change slowly and thus would not account for a sudden change in offer prices during a summer heat spell, (e.g., seasonal or annual energy limits, high operating costs at maximum capacity, gas prices, variable O&M costs, heat rates and emission allowance costs would not change materially from day to day).[109]

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[109] The heat rates, emission allowance costs and variable O&M costs of some units may, however, vary systematically with air and water temperature but these trade-offs should be known to the system operator and will result in regular changes in offer prices that are related to the air or water temperature at the unit location. PJM's dispatch software even includes the specification of weather points at which temperatures are to be used to adjust the capacity of specific generators. "PJM Manual for Scheduling Operations, Manual M-11," effective date May 18, 2001, Section 2, p. 2-6.

The offer prices of units with daily energy limits might change materially from day to day and even hour to hour but the identify of such units should be known to the ISO and they should be scheduled to provide reserves. In addition, loss of equipment at a unit may lead to a relatively sudden change the variable O&M costs, heat rate or NOx emission rate at a unit, but these outages will not occur every time the weather is hot.

In well designed LMP markets such as those coordinated by PJM and NYISO, efforts to materially raise prices through significant economic withholding will usually be readily apparent. An important feature of the PJM and NYISO markets is that they are based on market-clearing prices. In markets with pay-as-bid elements or markets in which opportunity costs are not reflected in prices, offer prices will vary systematically with market conditions for reasons unrelated to the exercise of market power. This is another negative feature of such market designs, their inefficiency also makes it more difficult to disentangle competitive behavior from the exercise of market power.

A fourth question would be to ask whether physical withholding of capacity for the purpose of exercising market power materially contributed to high prices. Determining whether on-line capacity was physically withheld from the market requires determining whether declarations of outages and deratings reflected actual operating problems, including low tide, high ambient temperature, etc. There is no easy short-cut. Higher than average forced outage rates and deratings will usually produce higher than average prices but it does not follow that all above average outage occurrences reflect the exercise of market power. Moreover, capacity may be physically withheld from the market for reasons unrelated to the exercise of market power, such as credit risk or compliance with laws, regulations and other restrictions. Nevertheless, while there may sometimes be individual operating situations in which it is difficult to assess the perceived risks of keeping a unit on line or operating it at a high level, sustained patterns of such withholding should be identifiable through statistical analysis.[110]

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[110] See, for example, Scott Harvey, William Hogan and Todd Schatzki, "A Hazard Rate Analysis of Mirant's Generating Plant Outages in California," January 16-17, 2004; PJM Market Monitoring Unit, "2002 State of the Market," March 5, 2003; David Patton, "Annual Report on the New York Electricity Markets 2000," April 2001; David Patton, "Annual Report on the New York Electricity Market 2001," June 2002; and David Patton, "2002 State of the Market Report NYISO," June 2003.

Ultimately, it is impossible to prove the absence of any withholding or any exercise of market power during the western electricity crisis without analyzing the reasons for every outage, derating, and decision not to operate by every supplier, which has not been undertaken by any study. The available information, however, has several elements that suggest that the exercise of market power by California thermal generators was not the primary cause of the high prices in California during 2000-2001. First, electricity prices were consistently high both inside and outside California, which strongly suggests that the problem was not the exercise of locational market power inside California but a widespread shortage of energy and/or capacity in the WSCC. Indeed, prices have at times been higher outside of California than within California due to transmission constraints on exports. Second, if thermal unit owners were engaged in a simple withholding of generation, then they would not have exceeded the environmental limits on their output. With the benefit of hindsight, it appears indisputable that perfectly competitive thermal generator owners of constrained units blessed with perfect foresight would have offered less capacity into the market from a number of units in many hours during the spring and summer of 2000 than they actually did, not more capacity, and prices in such a perfectly competitive market would have been higher, not lower, than the actual prices in many of the hours in early 2000. Third, if the high prices in California were attributable to simple withholding by a few thermal generators in California, could these generators be exercising sufficient market power to raise prices off-peak as well as on-peak throughout the entire WSCC?

While it is important that assertions of the exercise of market power be carefully investigated, the evidence to date that the high prices in California and the WSCC arise mainly from the exercise of market power by California thermal generators is far from compelling. Many factors contributed to higher prices in California during 2000 and 2001, and the market power theme is only, at most, part of the story. The import of the sensitivity analyses summarized here is not to prove that market power has not been exercised but, rather, to suggest that it is unlikely to be the dominant factor and may not even be significant. Simply attributing the bad outcomes in the west to the exercise of market power distracts attention from identification of the root causes of the crisis. Moreover, a focus on solutions addressing market power will leave the west ill prepared if or when the conditions that produced the crisis recur.

Table 2 Summary of Assumptions and Sensitivities						
	Simulations			**Withholding Analysis**		
	Joskow-Kahn	**BB&W**	**H-H Sensitivity**	**Joskow-Kahn**	**Reynolds**	**NYISO**
Operating reserves	None	None	R2/R5	Partial	Partial	Actual
Regulation	3%	3%	3%	Partial	Partial	Actual
Startup and minimum load costs	None	None	RUO N1-3	Test 1	Yes	Actual
Inter-zonal congestion	None	None	B-16	Yes	Yes	Actual
Intra-zonal congestion	None	None	None	No	No	Actual
Ramping constraints	None	None	None	No	Partial	Actual
Operating hour limits	None	None	None	No	NA	Actual
Outlet temperature limits	None	None	E1-E3	No	No	Actual
Deratings and operating problems	NERC Ave.	NERC Ave.	NERC Ave.	None	Some	Actual
RMR contracts	None	None	None	NA	NA	Actual
Market and dispatch inefficiency	None	None	None	No	No	Actual
Uncertainties						
O&M costs	Est.	Est.	Est.	Est.	Est.	Est.
Heat rates	Est.	Est.	Est.	Est.	Est.	Est.
Capacities	Est.	Est.	Est.	Est.	Est.	Est.
NOx allowance costs	Est.	Est.	Est.	Est.	Est.	Est.
Fuel costs	Est.	Est.	Est.	Est.	Est.	Est.
Import supply curve	Est.	Est.	Est.	NA	NA	NA
Non-NUG output	Model/ Est.	Model/ Actual	Model/ Actual	NA	NA	NA
Outage rates	NERC	NERC	RUO N-3	Actual Test 1	Actual	Actual
Outage risk and extra-ordinary cost at high output	None	None	No	No	No	Est.

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