The Effects of the Dysfunctional Spot Market for Electricity in California on the Cost of Forward Contracts*

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ABSTRACT

The unexpectedly high spot prices for electricity in the summer of 2000 that occurred in California led to a number of regulatory interventions. Initially, price caps were lowered in California from $750/MWh to $250/MWh during the summer. However, Out-Of-Market (OOM) purchases were still made above the price cap if capacity shortfalls occurred in the market run by the California Independent System Operator (CAISO). After evaluating the price behavior during the summer months, the Federal Energy Regulatory Commission (FERC) declared that the market in California was "seriously flawed" and proposed a number of changes to the market rules. Two important proposals made by the FERC were 1) to require greater dependence on forward markets by entities with obligations to serve customers, and 2) to replace the price cap of $250/MWh by a new type of "soft-cap" auction with the price cap at $150/MWh. Unfortunately, spot prices in the winter of 2001 were persistently much higher than the soft cap. These high spot prices created uncertainty that resulted in high premiums for risk and high forward prices. Hence, forward contracts executed at this time were very expensive for buyers, and many contracts were executed due to the directive of the FERC. After the FERC imposed a system-wide price cap on the whole Western Inter-Connection in June 2001, both the spot prices and forward prices for electricity returned to normal levels.

Earlier research has shown that the high spot prices of electricity in the winter of 2001 may have resulted from the new type of soft-cap auction combined with the high spot prices of natural gas delivered in California during the early part of the winter. The econometric analysis in this paper shows how forward prices for electricity responded in the winter of 2001, and concludes that uncertainty about the high prices for electricity and uncertainty about the supply of natural gas were both important. The relative effects of these two sources of uncertainty on forward prices vary by the date of delivery. The initial uncertainty about spot prices for electricity in the summer of 2000 increased the forward prices of electricity for summer deliveries more than for winter deliveries. In contrast, uncertainty about the spot prices of natural gas in the winter of 2001 increased the forward prices of electricity for all delivery months. Price shocks for electricity after the FERC intervened in the CAISO market had by far the largest effect on the forward prices for delivery in summer months.

1. Introduction

Many papers and reports have been written about the energy crisis in California and their overall conclusions are generally consistent with each other. Suppliers of electricity were able to exploit market power and increase the spot prices in the central markets run by the California Power Exchange (CAPX) and the California Independent System Operator (CAISO) during the summer of 2000. The most widely cited papers conclude that suppliers withheld generating capacity from the market to increase prices. Joskow and Kahn (2002) analyze data at the firm level and Borenstein, Bushnell and Wolak (2002) use a Cournot model of the spot market, and both conclude that prices were higher than competitive levels. A similar conclusion was reached by staff in the CAISO Department of Market Analysis (Hildebrandt, 2001). The vulnerability of the market to exploitation should not have been a surprise to the FERC. Wolak (2003a and 2003b) summarizes the numerous reports from the California Market Surveillance Committee, beginning in 1998, citing the lack of forward contracting and the lack of price-responsive wholesale demand as the primary design flaws. These conclusions were also reached by Faruqui et al (2001).

After the high prices experienced during the summer of 2000, the Federal Energy Regulatory Commission (FERC) intervened in the market in November 2000 under the "just and reasonable" standard for prices that is the key regulatory feature of the Federal Power Act. The FERC declared that the wholesale market in California was "seriously flawed" (FERC, 2000). The high wholesale prices were passed on to customers in San Diego because these customers were no longer covered by regulated "transition rates." Chairman Hoecker said, "Never has this Commission had to address such a dramatic market meltdown . . . [and] never have residential customers been as exposed to economic risk and financial hardship." (FERC, 2000). Many hearings have been initiated at the FERC since the summer of 2000 to determine which customers are eligible for refunds, including buyers outside California. These hearings have established that the wholesale market in California was "dysfunctional" from May 2000 to June 2001.

"The single most important remedy that the California market needs is the elimination of rules that prevent market participants from managing risk." (FERC, 2001). The FERC cited the lack of forward contracts as a major deficiency of the market in California. As Wolak (2003a) explains, this deficiency was not the result of rules imposed by the CAISO on the incumbent utilities that had the responsibility of serving load. Since these utilities were being paid a high regulated rate by customers, it did not appear necessary to hedge purchases in the spot market. These utilities were required to make purchases in the CAPX and CAISO markets, but this did not preclude holding contracts-for-differences, for example. If spot prices were a little higher than expected, this would simply extend the transition period. No plans were made for paying spot prices above the transition rates.

Regardless of the causes, the proportion of load covered by forward contracts in California was relatively low in the fall of 2000. The FERC proposed penalties for utilities that had to schedule deviations of more than 5% of their load in the CAISO balancing market (FERC, 2000). The FERC order resulted in a rush to sign contracts in the forward market during the winter of 2001. Unfortunately, the problem of high prices in the spot market had still not been solved, and the prices in the forward market were also unusually high when these forward contracts were executed.

A second feature of the FERC Order in November 2000 was to replace the existing auction in the central market by a new type of "soft-cap" auction. Although the CAISO had lowered the "hard" price cap in the balancing market from $750/MWh to $250/MWh during the previous summer, spot prices continued to be higher than historical levels. In other words, these regulatory interventions by the state had not been effective. In addition, capacity shortages had occurred in the balancing market that required making Out-Of-Market (OOM) purchases at prices above the cap. The soft-cap auction introduced by the FERC, in effect, made this practice standard. Purchases below the soft-cap (set initially at $250/MWh and then reduced to $150/MWh in January 2001) were paid the same market-clearing price equal to the highest (last) accepted offer in a uniform price auction. If additional capacity was needed to meet load, these purchases above the soft-cap were paid the actual offer in a discriminatory auction.

The initial plan was that suppliers would have to justify the production cost of purchases above the soft-cap to the FERC. However, this latter policy, like the penalties for relying too heavily on spot purchases, was not enforced effectively. Suppliers were able to distort the reported prices of inputs such as natural gas (FERC, 2002) and emission permits (Kolstand and Wolak, 2003). The soft-cap auction failed dismally as a regulatory strategy for ensuring that prices in the spot market were just and reasonable. Mount *et al.* (2003) argue that the combination of high prices for natural gas combined with the soft-cap auction exacerbated the problem of high spot prices of electricity. Selling capacity above the soft-cap leads to relatively flat (elastic) supply curves. Consequently, the effectiveness of reducing load as a way to lower prices is undermined. In a typical uniform price auction, the supply curve is like a hockey stick, and as a result, price-responsive load is an effective way to mitigate high prices (see Neenan, 2002, for an example from New York State).

For this paper, the causes of the high prices in the soft-cap auction are not as important as the consequences. Although most published analyses have focused on the high prices in the summer of 2000, the spot prices in California were even higher in the winter of 2001. Normally, winter prices are lower than summer prices, and the high winter prices were one of many unpleasant surprises for buyers. The high spot prices, the new soft-cap auction, the high prices for natural gas and the bankruptcy of Pacific Gas and Electric all contributed to uncertainty about the future performance of the market. At the same time, forward prices of electricity were also much higher than normal levels, and this was exactly the time that many forward contracts were signed. Since the incumbent utilities had insufficient credit to purchase forward contracts, the California Department of Water Resources was authorized to make forward purchases on their behalf.

The changing conditions in the spot market are summarized in Figure 1. Using the spot prices for the trading hub in Southern California from 1/1/99 to 12/1/01. This price series was chosen because it reflects unregulated bilateral trading before and during the period when the central market was dysfunctional. (There are problems with using the reported prices for the central markets which are discussed in Section 2). The hard and soft price caps enforced in the central CAISO market are also shown for reference. Unlike the earlier price caps, the final hard price cap of $93/MWh was imposed by the FERC in June 2001 on the whole Western Interconnection (or WECC). The important implication of Figure 1 is that the prices in the winter of 2001 were much higher than normal and consistently above the soft cap of $150/MWh. Since the FERC has ruled that the spot market in California was dysfunctional from May 2000 to June 2001, the federal regulators are consistent with the literature cited above. The main issues of contention relate to the spatial and temporal extent of this dysfunction, and in particular, on whether spot purchases at locations outside California and forward contracts are eligible for refunds.

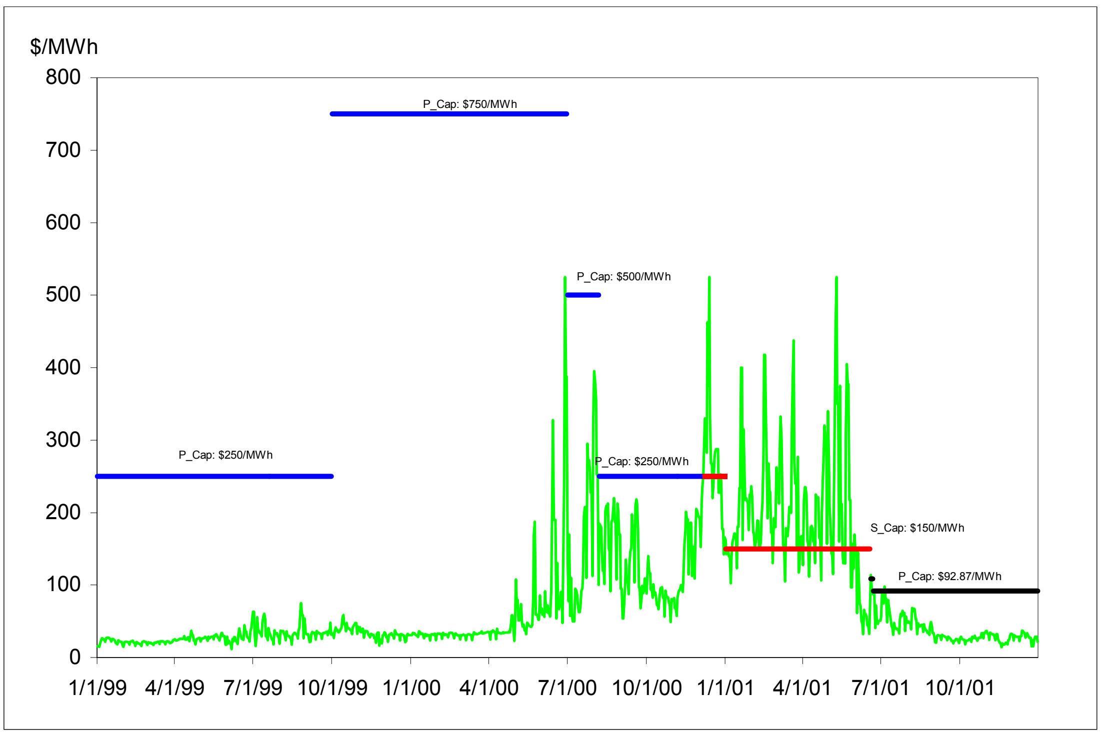

Figure 1: Spot Prices at Southern California and the Price Caps in California,
Blue CAISO Hard Cap
Red CAISO Soft Cap
Black WECC Hard Cap
(Source, Energy Market Report and the CAISO)

The objective of this paper is to address two issues of contention faced by the FERC, and to show that 1) the spot prices at different trading hubs throughout the WECC were highly interdependent, and 2) that the unexpectedly high spot prices resulted in high forward prices due to the uncertainty about future conditions in the market. In other words, the dysfunction in California market spread to the whole WECC and was also responsible for the high forward prices in the winter and spring of 2001 when forward contracts were being executed. Section 2 estimates the relationships among the spot prices at six different trading hubs and the CAPX. Section 3 describes how the forward price curve at one trading hub changed before, during and after the period of dysfunction in California. Section 4 estimates the relationships between the spot and forward prices at the trading hub described in Section 3 for different delivery dates, and Section 5 determines the corresponding affects of the dysfunction in the spot market on these forward prices. Finally, the conclusions of the analysis are summarized in Section 6.

2. The Relationships among Spot Prices at Different Trading Hubs

The main purpose of this section is to justify using forward price data from Arizona in the following sections to evaluate the market in California. The analysis shows that the spot prices at different trading hubs in the WECC, including the CAPX, are highly interrelated. Consequently, the dysfunctions affecting the California market from May 2000 to June 2001 also affected the spot prices at other trading hubs in the WECC, and the choice of the specific location for an analysis of forward prices is unlikely to affect the general conclusions. (This has practical implications because the availability of reliable data on forward prices is relatively limited.) Since the primary purpose of the paper is to analyze the relationship between spot and forward prices, the discussion of the econometric results for spot prices in this section is limited. More detailed results are given in Appendix A.

In this section, Vector Auto Regressive (VAR) models of spot prices were estimated for three different locations in the WECC: Mid-Columbia in the Pacific Northwest, Mead in Nevada, and Palo Verde in Arizona, and at four different locations in California; the California-Oregon Border (COB), Northern California, Southern California, and CAPX. The results show 1) all trading hubs exhibit the same type of structural shifts associated with the use of a soft-cap auction in California, 2) all trading hubs have a set of dynamic features in common, and 3) these interdependencies cover the period when the market for electricity in California was dysfunctional.

The spot prices for Mid-Columbia, Mead, Palo Verde, COB, Northern California and Southern California were obtained from Energy Market Report, and these data cover the period 1/1/99 to 8/31/02 for a total of 1339 daily observations of the on-peak spot price. The corresponding data for the CAPX were obtained from the Internet site for POWER at the University of California, Berkeley (the Internet site for the CAPX is no longer available). For reasons explained below, only data for the CAPX to 12/7/00 were used in the econometric analysis.

After the FERC ordered that a soft-cap auction would replace the existing balancing market operated by the CAISO in December 2000, the CAPX ceased to operate. The use of a soft-cap auction was associated with a period of extremely high spot prices in the winter of 2001. However, these high prices were not reported directly by the CAISO. The reported prices were truncated at the level of the soft-cap during the winter of 2001. This can be seen in Figure 2 by comparing the CAISO prices with the corresponding prices for the trading hub in Southern California. Since the CAISO data are truncated, analyses involving spot prices from the central market in California were limited to the period up to 12/7/00 before the soft-cap auction was introduced. Prior to the soft-cap auction, most sales in the central California market were made in the day-ahead auction operated by the CAPX, and these are the spot prices used in the econometric analysis for the period 1/1/99 to 12/7/00.

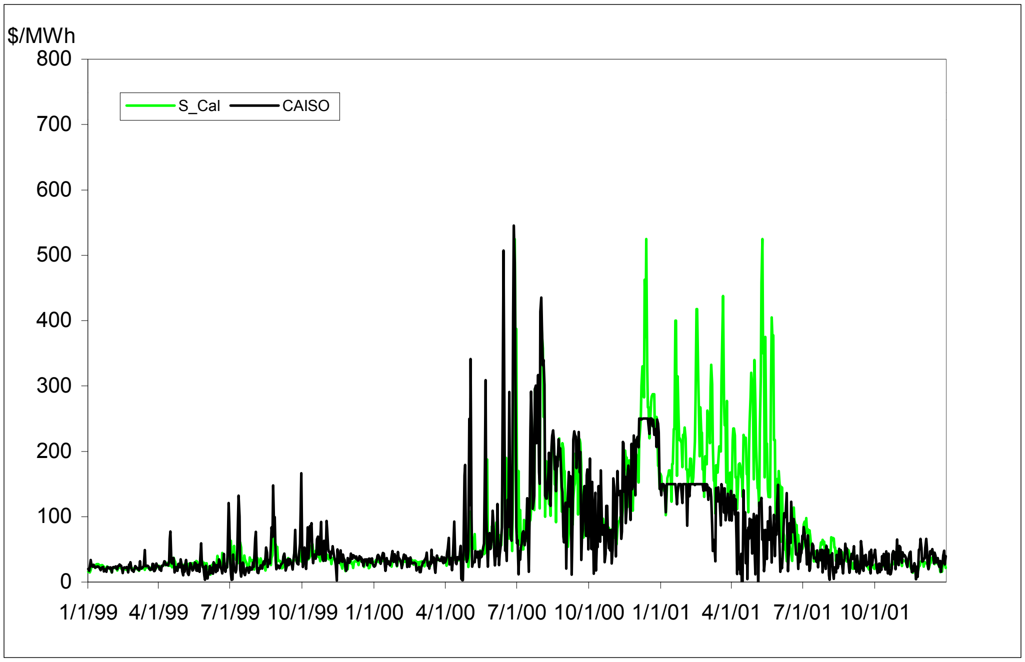

Figure 2: Spot Prices of Electricity for the California ISO and Southern California (Source, California ISO and Energy Market Report)

In an econometric analysis, a "structural" model includes measured explanatory (input) variables, like the prices of fuels used for generation. In contrast, a "time series" model does not include measured explanatory variables, and all of the measured variables are dependent (output) variables in a time series model. The values of these dependent variables in earlier time periods (lagged dependent variables) are used as explanatory variables together with simple functions of time, such as seasonal cycles. A time series model was used for this analysis because much of the information needed to develop a structural model was not available. In fact, the general lack of public data, in addition to the CAISO prices in the winter of 2001, is a major handicap for understanding what happened to electricity prices in California.

In the VAR model, the daily spot prices (in logarithms) at different locations are the dependent variables, and each spot price is regressed on the same set of seasonal variables, structural shift variables and the lagged values of all prices. The seasonal variables represent the typical annual pattern of spot prices (e.g. higher prices during the summer and winter months due to higher production costs), the structural shift variables reflect the use of a soft-cap auction in California, and the lagged prices allow for dynamic responses and interdependencies among the trading hubs.

The standard seasonal pattern of high spot prices in the summer and winter months and low prices in the spring and fall is represented by two sine/cosine waves (representing a one year and a half year cycle). In addition, dummy variables for Saturdays, Sundays and national holidays are included to account for the relatively low prices on these days. All of these variables represent the normal pattern of changes in the mean price associated with changes of production costs.

Compared to previous winters, the increases in spot prices after the soft-cap auction was introduced in December 2000 were dramatic and unexpected. For this reason, structural shifts were incorporated into the VAR model for the period when the soft-cap auction was operating from December 2000 to June 2001. In June 2001, a hard price cap was enforced by the FERC throughout the WECC. Consequently, additional structural shifts were incorporated for this latter period to distinguish conditions when the soft-cap auction was operating from other periods. For all trading hubs other than the CAPX, each structural shift was specified by two different variables. One structural variable was a dummy variable for each specified period (i.e., one during the soft-cap market and another after the soft-cap market), and the other structural variable was an inverse function of the number of days in each period (i.e., 1, 1/2, 1/3, 1/4, . . ., starting with the first day of the structural shift) and zero otherwise. The reason for including these inverse variables was to account for the very high spot prices that coincided with the introduction of the soft-cap market in December 2000, and to allow for a gradual adjustment of spot prices back to normal levels after the soft-cap auction was replaced.

Although it is possible in theory to estimate a single VAR model that includes the spot prices for all seven trading hubs, this could not be done in practice because the prices are so closely related to each other (see Figures 3 and 4). Hence, two different VAR models were estimated in two steps using only four trading hubs in each model to maintain computational accuracy. Each equation in a second order VAR model for four prices covering the full sample period has 2x4 = 8 lagged prices, an intercept and 11 coefficients for the seasonal and structural shift variables to give a total of 20 coefficients (the four structural shift variables are not included if the model uses only data prior to December 2000). By estimating the VAR model in two stages, the number of coefficients estimated in each stage is reduced substantially and the computations are tractable. In the first stage of the estimation, the four spot prices were transformed to logarithms and the effects of seasonality and structural shifts were removed from each price series using ordinary least squares. The computed residuals from the first stage were then used as dependent variables in the second stage to estimate a second order VAR model. (It should be noted that the first stage models are the same regardless of which spot markets are grouped together in the second stage of the model.)

The seasonal effects and the structural shifts associated with the soft-cap market in the first stage estimation account for over 60% of the total variability of the spot prices at all locations other than the California Power Exchange (the unexplained variability in this market is similar in size to the other locations, but the total variability is lower because the data period stops in December 2000). The most important feature of the first stage estimation is that the coefficients of the structural dummy variable for the soft-cap auction are all positive and highly statistically significant in all six spot markets (i.e., excluding the spot prices at CAPX because this model does not use data when the soft-cap auction was operating). These results show that the changes in the auction rules implemented by the FERC in the CAISO market were associated with increases of spot prices at all trading hubs in the WECC. The effects of the soft-cap auction were not limited to California. In fact, the estimated shifts are largest in Mid-Columbia and COB, corresponding to increases of over 700% from the normal seasonal levels. After a hard-cap on spot prices in the WECC was introduced in June 2001, the structural shifts for all trading hubs imply that prices fell to at least 30% below the levels prior to the introduction of the soft-cap auction. Once again, there is consistency in the structural shifts at all trading hubs.

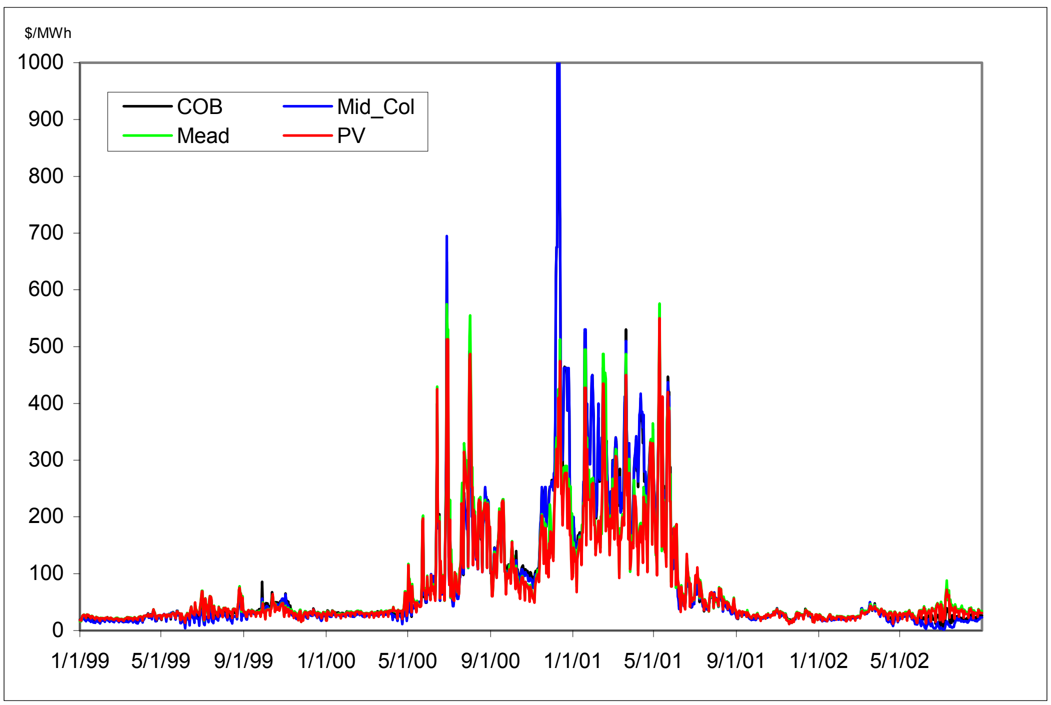

Figure 3: Spot Prices of Electricity at Four Trading Hubs in the WECC
(Source, Energy Market Report)

In the second stage of the estimation, the computed residuals from the first stage estimation are used as the dependent variables to estimate a VAR model and account for the serial correlation that exists in these residuals. Since a first order VAR model could not explain all of the serial correlation, it was necessary to estimate a second order VAR model. In addition, it was not practical to estimate a single VAR model for all seven markets due to the high collinearity among the lagged dependent variables. As a result, models with only four trading hubs were specified. The first group of four trading hubs covers the full geographical range of the WECC from the Pacific Northwest to the Southwest (Model A: Palo Verde, Mid-Columbia, Mead and COB). The spot prices for these four locations are shown in Figure 3. The four trading hubs in the second group are in California (Model B: COB, Southern California, Northern California and CAPX). Since CAPX data are used, the estimation of Model B is based on prices before the soft-cap auction. These prices are shown in Figure 4. Since the prices shown in Figures 3 and 4 are closely related together, the results from estimating the VAR models simply confirm this fact.

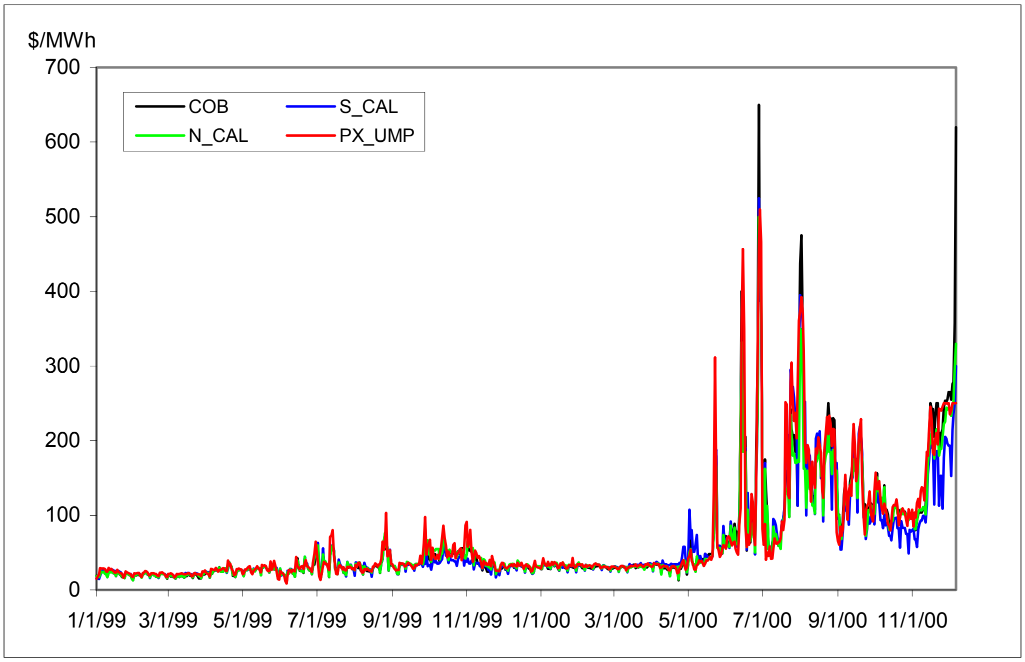

Figure 4: Spot Prices of Electricity at Four Locations in California
(Source, California ISO and Energy Market Report)

The computed residuals from the second order VAR models pass most of the desired tests for being white noise, and the models are reasonably consistent with the statistical specifications. For any one of the four price series in either Model A or Model B, there are two lagged prices of the same price series and six lagged prices from the other three price series. In general, if the lagged prices of the other series are statistically significant, it implies that each price series shares a common dynamic structure with the other three price series. If these "cross-price" coefficients are not statistically significant, then the dynamic structure of each price series is independent of the other price series. In the estimated model, there are 24 cross-price coefficients and 8 own-price coefficients for the four price series.

The estimated coefficients shown in Table 2 of Appendix A imply that 21 out of the 24 cross-price coefficients are statistically significant (i.e. not equal to zero) in Model A. As a result, there is strong statistical evidence that the spot prices at four different locations in the WECC share a common dynamic structure and are highly interdependent.

The three cross-price coefficients that are not statistically significant correspond to second order effects. Since all of the first order effects among the four locations are statistically significant, it implies that price shocks in any one of the four locations will affect the other three locations in the WECC. All four locations are interdependent and this implies that spot prices from Arizona to Washington State effectively belong to a single market. The results for Model B are similar, and 23 of the 24 cross-price coefficients are statistically significant from zero. This result provides direct statistical evidence that spot price behavior in the central market in California affected the spot prices at other locations. (It should be noted that both Models A and B include spot prices at COB.)

Combining the results of a shared dynamic structure for spot prices at different locations with the finding that all trading hubs were affected similarly by the structural shifts associated with the introduction of a soft-cap auction in California provides overwhelming statistical evidence. The high spot prices in California when the market was dysfunctional were transmitted to other trading hubs throughout the WECC. This conclusion has important implications for FERC in determining which customers are eligible for refunds for purchases of electricity in the spot market. If spot prices in California were unjust and unreasonable, they were also unjust and unreasonable at the other trading hubs in the WECC.

3. The Behavior of Forward Prices when the Market was Dysfunctional

The objective of this section is to describe how forward prices for electricity behaved. However, reliable data on forward prices are difficult to obtain. For example, trading on the New York Mercantile Exchange (NYMEx) for locations in the WECC virtually ceased when the market in California was dysfunctional, and most forward trading was over-the-counter using organizations like Enron-On-Line (EOL). The situation is quite different from natural gas. Trading on NYMEx for delivery at Henry Hub in Louisiana is very active, and these prices provide a valuable benchmark for trading at other locations. An important practical difference between NYMEx and EOL is that trading on NYMEx is governed by a strict set of rules. These include not allowing bogus trades such as “wash” trading between two affiliated firms (to distort the prices reported in the market), and most importantly, not allowing NYMEx to hold positions in the market. The potential profits from combining these two practices together were too tempting for EOL on the West Coast (see FERC, 2002).

The forward prices of electricity used in this section are monthly quotations for on-peak delivery at Palo Verde for different delivery months in the future (the quotations correspond to the first trading day of each month). These data were obtained from a utility company (Utility A) in the WECC that had responsibility for meeting load. Hence, these are valuable data for research because they represent the information used to make decisions about forward contracts. The corresponding forward prices of natural gas for delivery at Henry Hub are readily available from NYMEx, and for reasons discussed in the following section, these prices are more appropriate for the analysis than prices for delivery in California.

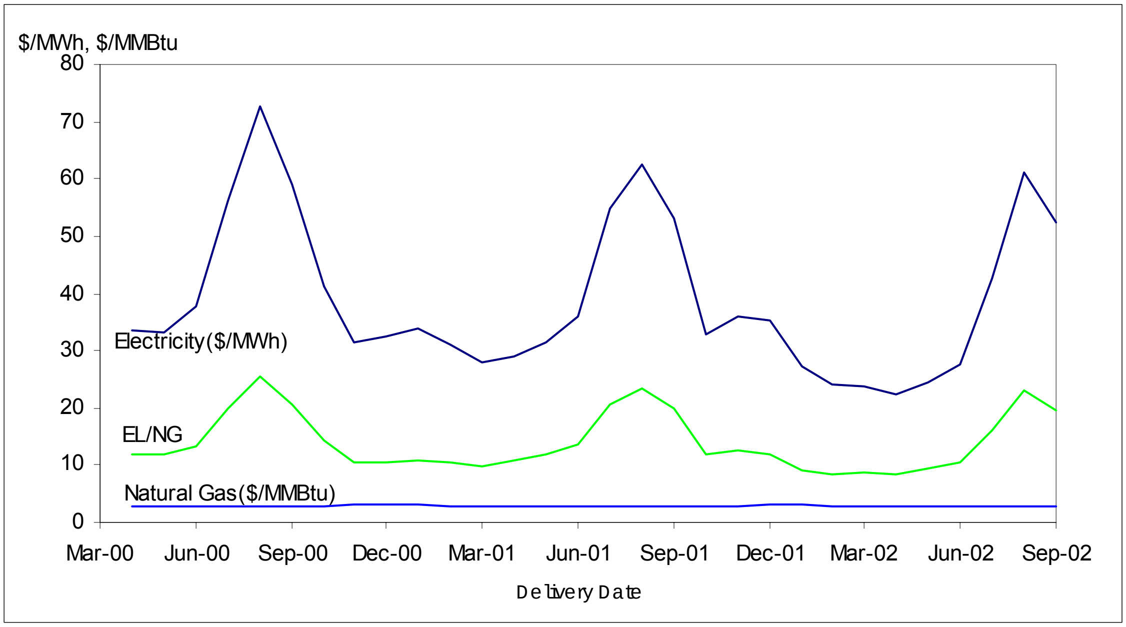

Figure 5: Forward Price Curves Quoted on 3/1/00 for Electricity at Palo Verde, for Natural Gas at Henry Hub, and the Corresponding Price Ratio
(Source, Utility A and NYMEx)

Figure 5 shows the forward price curve for electricity at Palo Verde (PV), the forward curve for natural gas at Henry Hub (HH) and the corresponding forward price ratios of electricity to natural gas (EL/NG) quoted on March 1, 2000 (i.e., these forward prices are the prices that could be set on March 1, 2000 for different delivery months in the future from April, 2000 to September, 2002). These forward curves represent market conditions well before the market became dysfunctional in the summer of 2000. Under normal conditions, each forward price corresponds to the expectations of market traders about the future spot price at the delivery date plus a risk premium. Even though the forward price curve for natural gas appears to be almost flat, the prices of natural gas are slightly higher in the winter than the summer. In contrast, the forward curve for electricity exhibits a strong seasonal pattern with the highest prices in the summer months and moderately high prices in the winter months.

The seasonal pattern of forward prices for electricity represents different market factors that affect the cost of operating a marginal generator. The high prices in the summer are roughly twice as high as the prices in the winter because relatively inefficient turbines (i.e., with high heat rates and high emission rates) are used to meet the high loads in the summer. For example, a combined cycle turbine, with an efficiency of 50% electric, could be the marginal generator in the winter, and a single-cycle jet engine, with an efficiency of 25% electric, could be the marginal generator in the summer.

The forward price ratio (EL/NG) in Figure 5 exhibits roughly the same seasonal pattern as the price of electricity. If the forward price of natural gas increased for some reason, one would expect the forward price of electricity to increase as well because natural gas is typically the fuel used by the marginal generator. Hence, using the forward price ratio is a convenient way to remove the effects of changes in the forward price of natural gas when evaluating the changes in the forward price of electricity that occurred when the spot market was dysfunctional. The forward price ratios are shown for three different trading dates in Figure 6. The forward price ratios on the earliest trading date (3/1/00) are identical to the ratios (EL/NG) shown in Figure 5. The other two trading dates correspond to 1) the middle of the summer of 2000 (8/1/00) after the spot prices of electricity had become unexpectedly high, and 2) a date just before the FERC introduced a soft-cap auction in California (12/1/00).

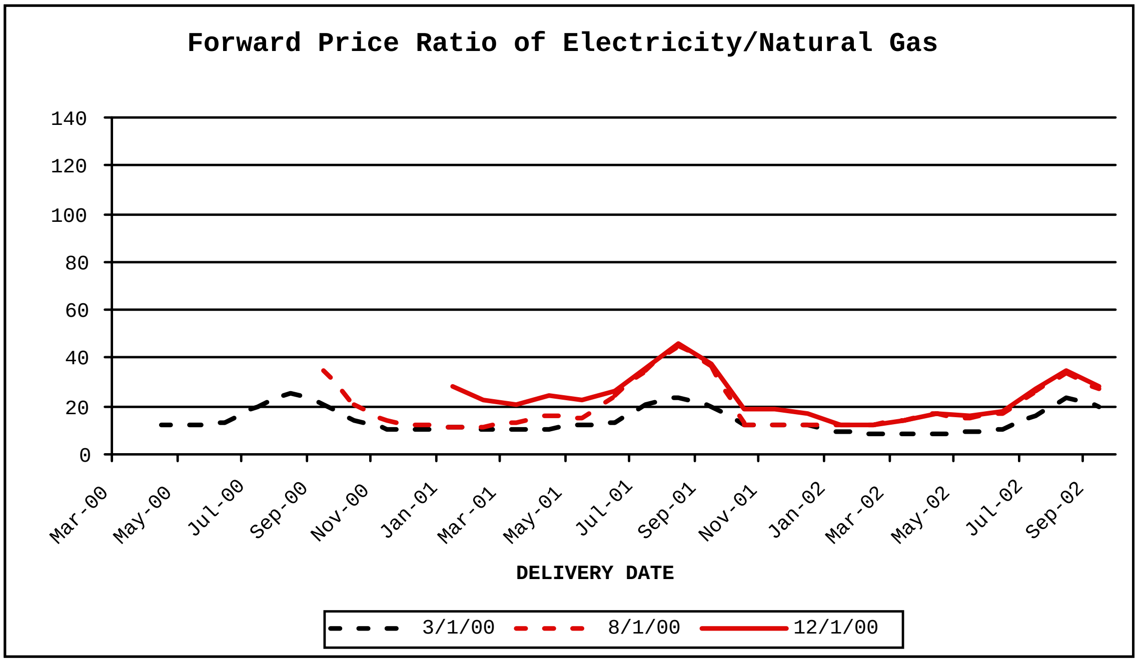

Figure 6: Forward Price Ratios of Electricity at Palo Verde to Natural Gas at Henry Hub for Three Trading Dates in 2000.

The high spot prices of electricity in the summer of 2000 were interpreted as primarily a summer problem, and the forward price ratios for the winters of 2001 and 2002 were similar to normal levels (i.e., the forward curve on 8/1/00 increased in the summer months much more than in the winter months, relative to the normal conditions represented by the forward curve on 3/1/00). There were few changes in the expectations of traders during the fall of 2000 and the forward curves on 8/1/00 and 12/1/00 are almost identical for delivery dates after March 2001. For earlier delivery dates, the forward curve on 12/1/00 was higher than it was on 8/1/00 because the spot prices of electricity had remained higher than normal in the fall of 2000. The main conclusion is that traders considered that the high spot prices of electricity relative to natural gas in the fall of 2000 did not represent a long-term change in the spot market, but the unusually high spot prices in the summer of 2000 were likely to occur again in future summers.

After the soft-cap auction was introduced in December 2000, the spot prices of electricity (and natural gas) were extraordinarily high (see Figure 2). Figure 7 shows that the forward price ratios for all months increased dramatically, reaching 125 for delivery in the summer of 2001 and over 70 for the summer of 2002 on 4/2/01. Comparing the forward curves on 2/2/01 and 4/2/01 implies that the forward price ratios for delivery in future summer months actually increased during the winter of 2001. In other words, traders interpreted the unusually high spot prices for electricity in the winter of 2001 as indicative of major changes in the spot market throughout the year and not just as a winter problem. Unfortunately for customers, the FERC Order from the previous fall resulted in many forward contracts for electricity being signed during the winter of 2001 when the forward prices of electricity were at their highest levels.

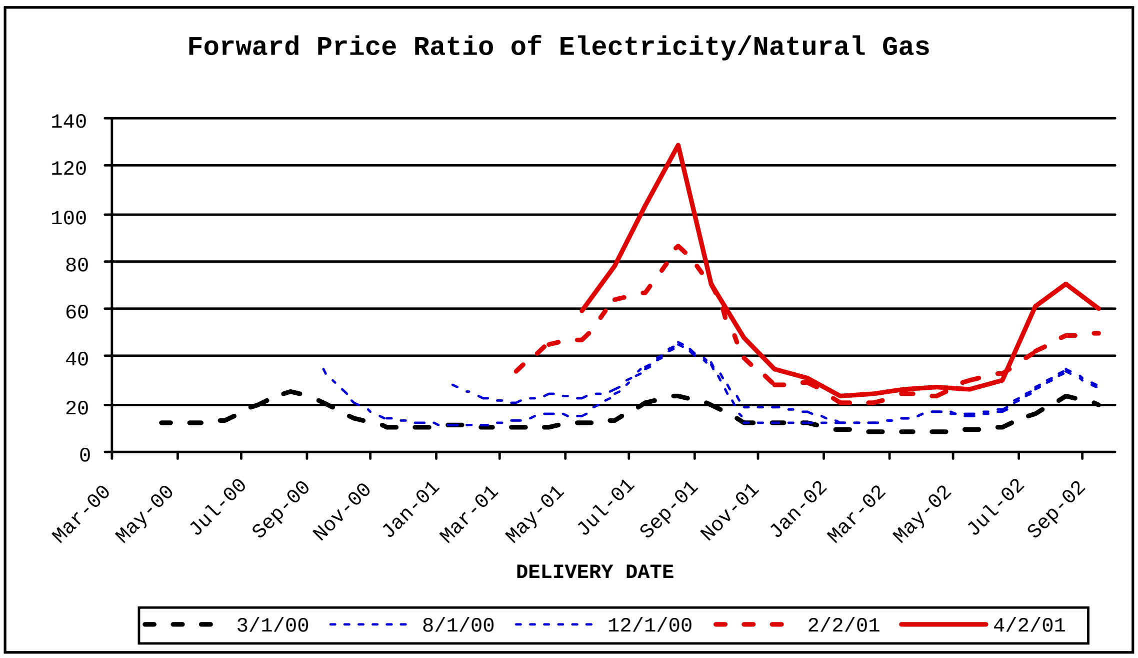

Figure 7: Forward Price Ratios of Electricity at Palo Verde to Natural Gas at Henry Hub for Five Trading Dates in 2000 and 2001.

In the winter of 2001, traders believed that the spot market for electricity was truly dysfunctional and that the spot prices of electricity would continue to be abnormally high into the future. Furthermore, both the FERC and the California state government did little at that time to reestablish confidence in the spot market. Compounding the concerns of traders about the spot market, Pacific Gas and Electric (PG&E) filed for bankruptcy. This was the first major electric utility to do so in the history of the industry. Firms with commitments to serve customers must have viewed this bankruptcy as a very ominous omen for the future. Any firm that continued to buy high in the spot market and sell low at regulated rates to customers could end up facing the same predicament at

PG&E. In this market, buyers were exposed to unacceptably high levels to risk (i.e., there appeared to be no limit on how high the price of electricity could go, and both federal and state regulators seemed reluctant to intervene in an effective way).

In contrast to the risk faced by buyers in a deregulated market for electricity, suppliers have a built-in call option when they own a generator because they do not have to sell if the spot price is below their operating cost (i.e., operating profits do not fall below zero for sales in the spot market). Consequently, there is an asymmetry of risk that is favorable to suppliers compared to buyers when forward contracts are made. More uncertainty about future spot prices will tend to make the risk premium higher in a forward contract. As a result, forward prices for electricity in a dysfunctional spot market are likely to be much higher than the true statistical expectation of the future spot price. This risk premium is an important reason why the forward ratios in Figure 7 on 2/2/01 and 4/2/01 were so abnormally high.

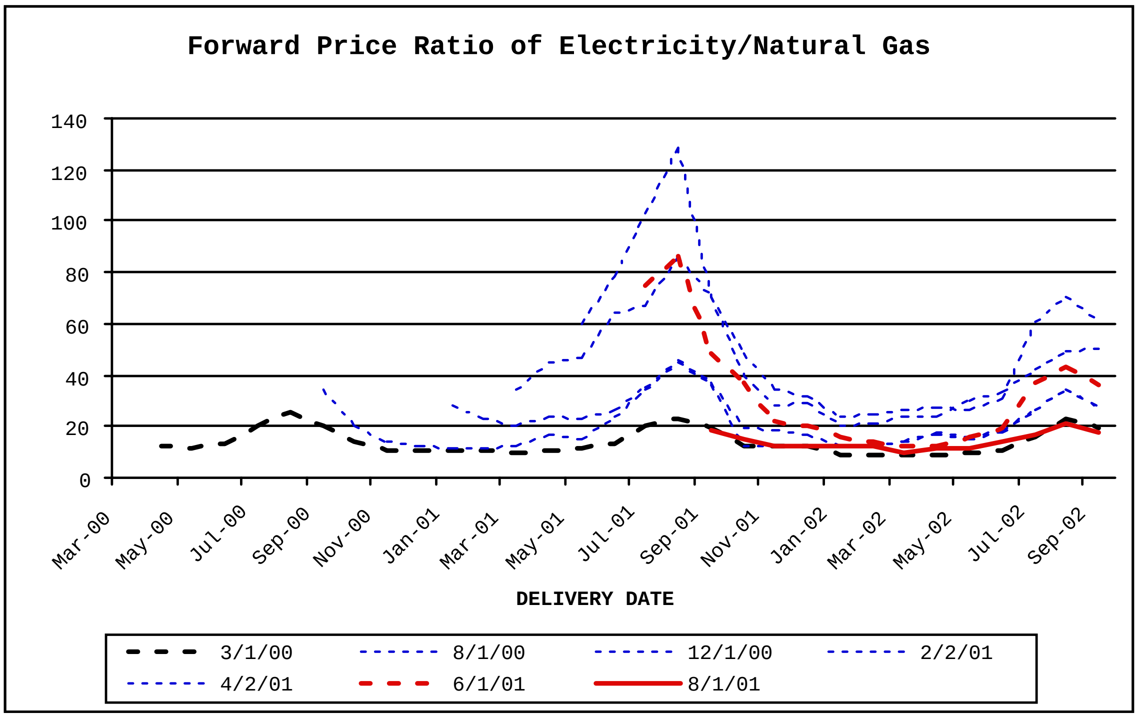

Figure 8: Forward Price Ratios of Electricity at Palo Verde to Natural Gas at Henry Hub for Seven Trading Dates in 2000 and 2001.

Figure 8 shows the forward the price ratio for two additional trading dates. The forward curve on 6/1/01 had shifted down from the forward curve on 4/2/01, but the ratios for the next two summer months in 2001 were still high (over 70) even though the ratios for the coming winter were back to normal. The ratios for the following summer of 2002 reach 40 and are similar to the corresponding ratios that were expected a year earlier during the previous summer on 8/1/00. In other words, traders still expected the market to have problems in the summer months, but they believed that conditions would return to normal in the winter months. When the actual spot prices of electricity continued to fall during the summer of 2001 (see Figure 2), traders believed the problem in the summer had also been solved. The forward curve on 8/1/01 has essentially returned to the original forward curve on 3/1/00 when market conditions were normal and traders expected that they would remain normal.

In summary, there were effectively two different types of dysfunction in the spot market for electricity. First, traders interpreted the unusually high prices in the summer of 2000 as a summer problem only. Second, the unusually high spot prices in the winter of 2001 were interpreted by traders as a much more serious problem that would persist and affect future prices in all months. By the end of the winter of 2001, forward prices for delivery in the summer months reflected the combination of both types of dysfunction. As soon as it became clear that regulators were determined to do something about the dysfunctional spot market, then confidence in the market returned. After a hard price cap was enforced by FERC throughout the WECC in June 2001, it appeared unlikely that the high prices experienced in the winter of 2001 would occur again. By August 2001, the low spot prices of electricity helped to convince traders that the problems of the previous summer had also been eliminated. Wolak (2003a) has argued that the increase of purchases from forward contracts at that time was also a major reason why spot prices returned to normal. There were probably a number of different reasons why both the spot and forward prices returned to normal in the summer of 2001. However, these reasons do not include any obvious reduction in production costs during the summer. For example, the spot price of natural gas fell steadily from February to August 2001 (see Figure 9 in the next section). Limiting the effects of market power and lowering the risk faced by buyers are the main reasons why conditions in the market returned to normal.

4. The Relationship between the Spot and Forward Prices of Electricity

An important policy issue is whether the high forward prices of electricity during the winter and spring of 2001 were affected by the high spot prices in the California spot market because many forward contracts were executed during that period. In this section, an econometric analysis shows that the unexpectedly high prices in the spot markets for both electricity and natural gas contributed to the high forward prices of electricity. The models have a structure that is consistent with economic principles, and explain the dramatic changes in the forward prices for specified delivery months from June, 2001 to August, 2002. Each model uses the ratio of the forward price of electricity at Palo Verde to the forward price of natural gas at Henry Hub (in logarithms) for a specified delivery month as the dependent variable. The basic structure of the model allows the forward price to converge towards the spot price as the trading date gets closer to the delivery date. However, the main purpose of the model is to estimate how the forward price ratio responded to conditions in the corresponding spot markets for electricity and natural gas.

The first step of the analysis is to separate the typical seasonal patterns of the spot prices from the price shocks when the market was dysfunctional. The forward curves quoted on 3/1/00, shown in Figure 5, represent the typical seasonal patterns before the market became dysfunctional. Figure 9 shows that the seasonal patterns of different forward curves (in logarithms), quoted on the first trading day of each month from November 1999 to March 2000, were all very similar to each other. For these months prior to the market dysfunction, changes in the expectations about forward prices were relatively minor. There were small parallel changes in the forward curves for natural gas, and small changes in the forward price ratio for the nearest delivery months. Since the earliest forward price data available for electricity at Palo Verde were for November 1999, the forward curves quoted on 1/11/99 were used to predict the normal seasonal pattern of prices for natural gas and the price ratio (EL/NG).

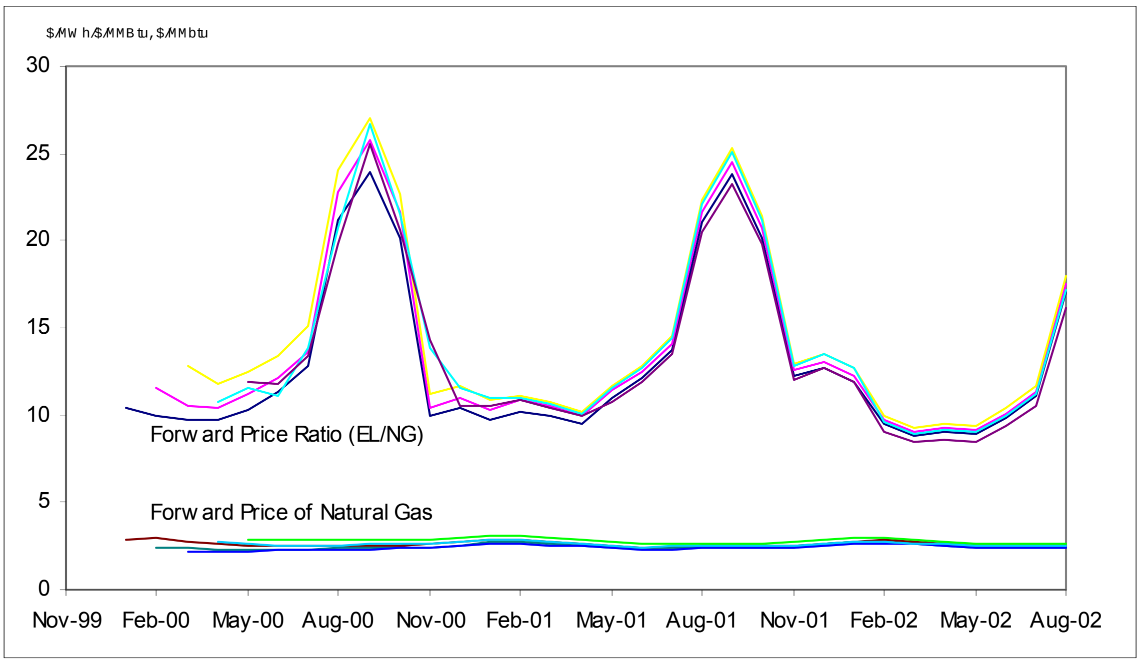

Figure 9: Forward Price Ratios of Electricity (Palo Verde) to Natural Gas (Henry Hub) and Forward Prices of Natural Gas on Monthly Trading Dates from 11/1/00 to 3/1/00
Source : Utility A and NYMEx.

Separate regression models were fitted for 1) the logarithm of the forward price ratio of electricity at Palo Verde to natural gas at Henry Hub quoted on 11/1/99, and 2) the logarithm of the forward price of natural gas at Henry Hub quoted on 11/1/99. Using the forward price ratio provides an estimate of the seasonal pattern for electricity conditional on the forward price of natural gas. The forward price ratio represents traders' expectations about the typical change in the ratio of the spot prices of electricity to natural gas associated with annual changes in the production costs of the marginal generator. The seasonal cycle is represented by a Sine and a Cosine variable plus a summer effect. The model also allows for an initial adjustment in the forward curve over time. The models for electricity and natural gas can be specified as follows:

Model for electricity (conditional on the price of natural gas)

$$FR_t = \beta_0 + \beta_1 T + \beta_2 Sin(\theta t) + \beta_3 Cos(\theta t) + \beta_4 D_t + \varepsilon_t \qquad [1]$$

Model for natural gas

$$FNG_t = \beta_0 + \beta_1 T + \beta_2 Sin(\theta t) + \beta_3 Cos(\theta t) + \varepsilon_t \qquad [2]$$

where

FR_t : forward price ratio of electricity to natural gas quoted on 11/1/99 (trading date) for delivery month t (in logarithms)

FNG_t: forward price of natural gas quoted on 11/1/99 (trading date) for delivery month t (in logarithms)

T: inverse time trend $(= \frac{1}{\sqrt{t+1}})$

Sin, Cos: yearly cycle variables with $\theta = 2\pi / 12$

D: summer variable (if month is July or September, D = 1; if month is August, D = 2; and D = 0 otherwise)

Table 1. Estimated Models of Normal Price Behavior

Parameters	Model for Electricity (1)	Model for Natural Gas (2)
β_0	**2.39689**	**0.93123**
	(0.04524)	(0.00955)
β_1	0.11285	**0.10623**
	(0.14205)	(0.03131)
β_2	**-0.19192**	**0.04471**
	(0.03446)	(0.00536)
β_3	0.00204	**0.04701**
	(0.02450)	(0.00538)
β_4	**0.31622**	-
	(0.03797)	-
R^2	0.9253	0.8738
SSE	0.2589	0.0130
DFE	28	29

The numbers in parentheses represent standard deviations, and bold coefficients have P-values < 0.05.

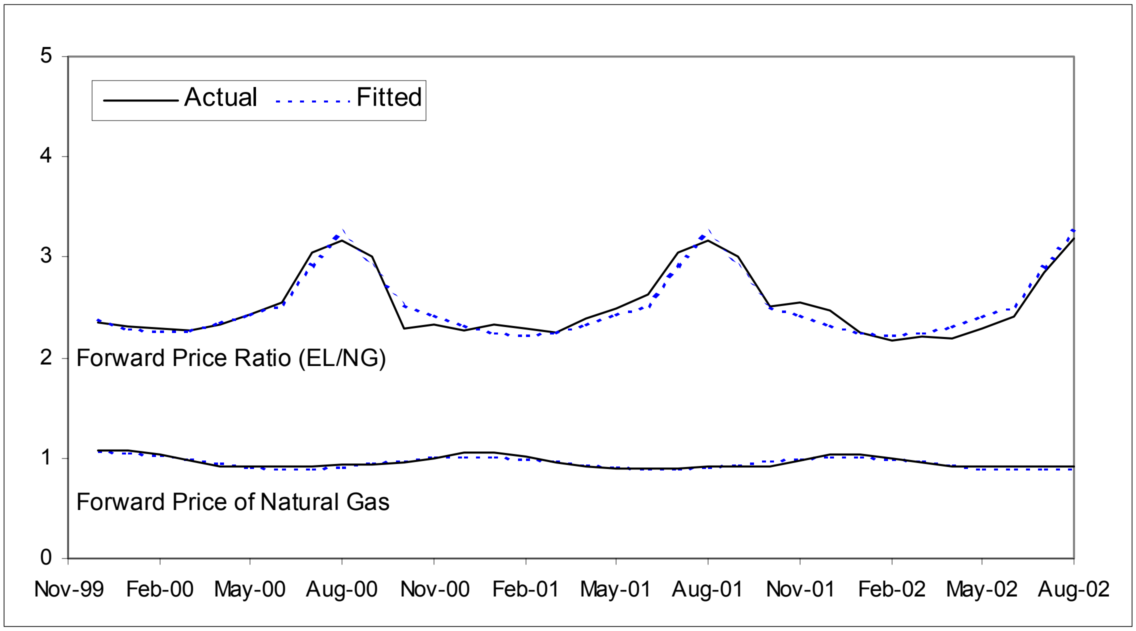

Figure 10: Actual and Fitted Forward Curves Quoted on 11/1/99 for the Price Ratio of Electricity to Natural Gas and for Natural Gas (in logarithms)
Source : Utility A for Electricity and NYMEx for Natural Gas.

For both electricity and natural gas, the fitted models in [1] and [2] represent price behavior under "normal" conditions. The regression results are summarized in Table 1, and the actual and fitted forward curves are shown in Figure 10. The models fit the data well and the coefficients are determined reasonably accurately.

The two estimated models in Table 1 were then used to predict the normal annual patterns of the corresponding daily spot prices of natural gas and the spot price ratio (EL/NG) (in logarithms). The monthly time variables were converted to days by scaling ($t_{month} = t_{day} / 30.5$). The actual and predicted normal daily values are shown in Figure 11. The important implication for natural gas is that the spot prices were persistently higher than normal from May 2000 to August 2001. The same is true for the price ratio from May 2000 to June 2001. However, for the price ratio, there is an important difference between the high values in the summer of 2000 and the winter of 2001. Since high price ratios are normal in the summer and not in the winter, the high values in the winter of 2001 were much more of a surprise to traders than the high values in the summer. The FERC concluded that the market had been dysfunctional in the summer of 2000, and in view of the results in Figure 11, the market must have been even more dysfunctional in the winter of 2001.

The differences between the actual and the fitted values in Figure 11 represent the "price shocks" in the spot markets for electricity and natural gas. From this point on, "price shocks" will be used to represent the uncertainty about current market conditions when spot prices departed from the normal seasonal patterns shown in Figures 10 and 11. Under normal conditions, the price shocks will tend to vary around zero. However, after

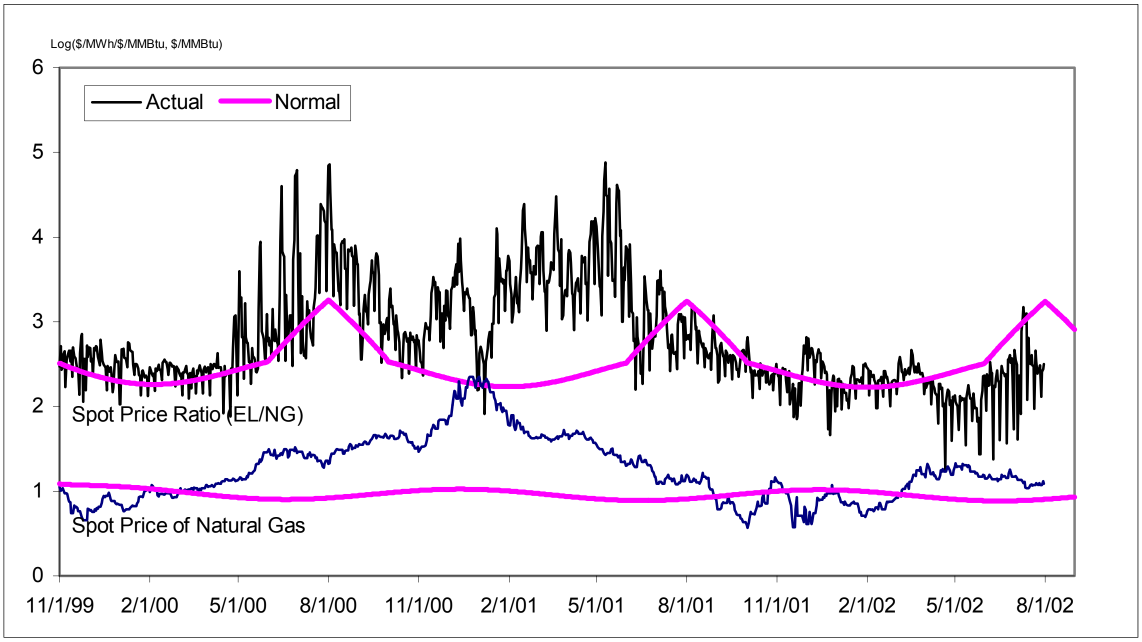

Figure 11: Spot Price Ratios of Electricity (Palo Verde) to Natural Gas (Henry Hub) and Spot Prices of Natural Gas (in logarthims)
Source: Energy Market Report for Electricity and Platts for Natural Gas

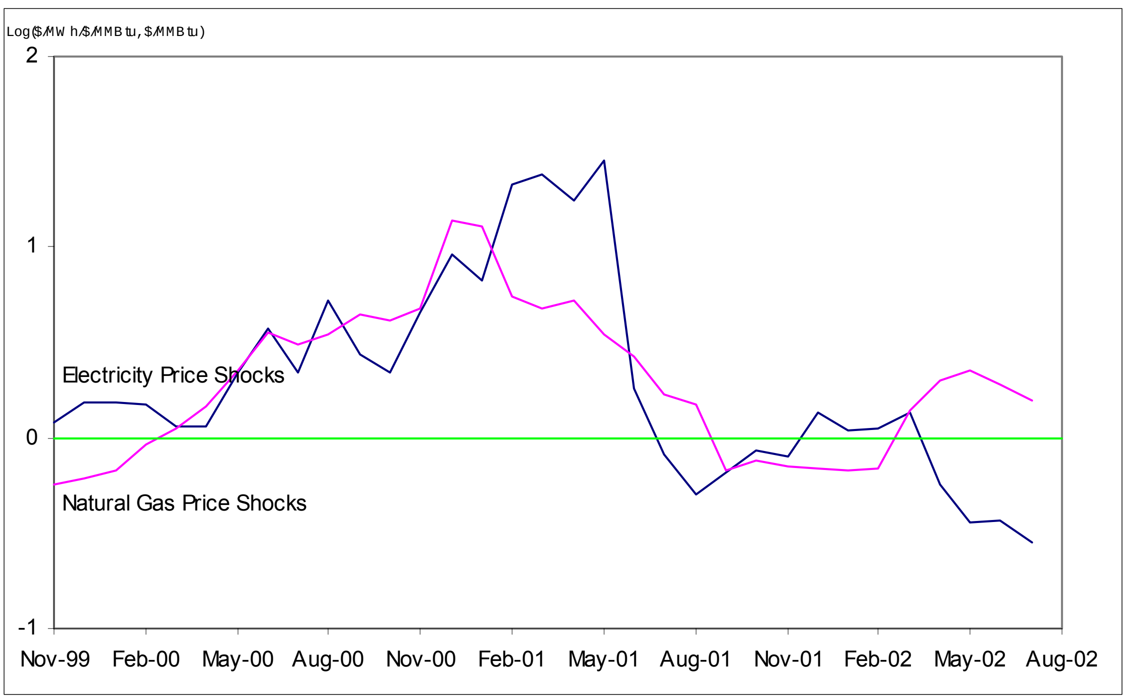

Figure 12: Monthly Average Price Shocks for Electricity and Natural Gas
Source : Derived from Figure 11

May 2000, both markets were abnormal and the price shocks were consistently positive. For electricity, the price shocks are computed from the price ratio, and therefore, are conditional on the current spot price of natural gas. In the summer of 2000, the price shocks for electricity are relatively small because higher prices are expected in the summer under normal conditions. In contrast, the price shocks for electricity in the winter of 2001 are much larger because prices are normally low in the winter. The monthly averages of the price shocks for electricity and natural gas are shown in Figure 12. (Monthly averages are shown because monthly data are used in the next part of the analysis). It is interesting to note that both price shocks in Figure 12 have similar patterns even though the effects of the high spot prices of natural gas have been removed from the price shocks for electricity. Both types of price shock were highest in the winter of 2001.

The next step in the analysis is to estimate the effects of the price shocks in the spot markets for electricity and natural gas on the forward price ratios for different delivery dates (i.e., to explain the changes in the forward price ratio described in Section 3). The model uses a weighted average of the actual spot price ratio (adjusted for seasonality) and a function of the price shocks in the spot market. The weights of both components of the model add to one. The weight for the adjusted spot price ratio increases to one as the trading date gets closer to the delivery date. At the same time, the weight for the function of price shocks goes to zero. This structure was specified to capture the economic principle that a forward price should converge to the spot price when the trading date approaches the delivery date. For the purpose of estimating the model, however, the price shock component of the model is completely dominant until the last two or three months before delivery.

The dependent variable in the model is the logarithm of the forward price ratio of electricity to natural gas (EL/NG). The first component of the model corresponds to a naïve forecast based on the observed spot price ratio in the previous month, adjusted for seasonal effects. If the current trading month is t and the delivery month is T, then the forecasted logarithm of the price ratio is:

$$FRf_{T,t} = \left(Pel_{t-1} - Png_{t-1}\right) + \left(FR_T - FR_{t-1,}\right) = PelS_{t-1} - PngS_{t-1} + FR_T\,,$$

where Pel and Png are the average spot prices for electricity and natural gas, PelS and PngS are the corresponding price shocks, and FR is the forward price ratio predicted in [1] (all in logarithms). Under this specification, the forecasted price ratio equals the actual price ratio when the trading month and the delivery month are the same (T = t-1).

The second component of the model incorporates the unexpected price shocks in the spot market using a distributed lag framework. The model implies that traders respond to a weighted average of past price shocks. Under normal market conditions, average price shocks will be close to zero, but when the market was dysfunctional, the price shocks were persistently above zero. The model estimates how the cumulative effects of these positive price shocks affected the risk premium for electricity in the forward market. Three different price shocks are identified in the model. These are 1) electricity before the soft-cap auction was introduced, 2) electricity after the soft-cap auction was introduced, and 3) natural gas. The specific form of the model can be written as follows:

$$FR_{T,t} = \beta_0 + (1 - W_t)FRf_{T,t} + W_t\left(\beta_1 + \beta_2 D_1 PelS_{t-1} + \beta_3 (1 - D_1) PelS_{t-1} + \beta_4 PngS_{t-1} + \beta_5 FR_{T,t-1}\right) + \varepsilon_t \qquad [3]$$

where t = 1,2,…,T is the trading month

T is the delivery month

W_t: $= 1 - \frac{1}{(T - t + 1)^2}$ is a specified weight between 0 and 1

$FR_{T,t}$ is the logarithm of the ratio of the forward prices of electricity at Palo Verde to natural gas at Henry Hub traded on the first business day of month t for delivery in month T

$FRf_{T,t}$ is the forecast of $FR_{T,t}$ made on month t (lagged spot price ratio adjusted for seasonal effects)

D_1 is a dummy variable for months prior to the soft-cap auction

$PelS_t$ is the conditional price shock for electricity for month t (deseasonalized spot price ratio in logarithmic form)

$PngS_t$ is the price shock for natural gas for month t (deseasonalized spot price in logarithmic form)

The inverse quadratic form of the weight W in [3] was selected on the basis of fit over a simple inverse function. The quadratic form implies that the weight is close to one for most of the sample, and therefore, the price shock component of the model is the most important for estimation. Initial versions of the model were simpler in structure, and in particular, the important role of the price shocks for natural gas was not anticipated. These simpler models are nested in [3], and the two most important can be specified in terms of which price shocks affect the risk premium as follows:

Conditional price shocks for electricity only (PelS) $\beta_2 = \beta_3$ and $\beta_4 = 0$

Unconditional price shocks for electricity only (PelS + PngS) $\beta_2 = \beta_3 = \beta_4$

Neither of these simple forms of the model were supported by the data. The final form of the model in [3] allows for different coefficients for PelS before and after the introduction of the soft-cap auction, and our expectation, based on the discussion in Section 3, was that the soft-cap auction introduced an additional source of uncertainty into the market that would increase the risk premium $(i.e., 0 < \beta_2 < \beta_3)$.

Table 2. Regression Results for the Forward Price Ratio in Summer Months

	Delivery Date (Summer 2001)			Delivery Date (Summer 2002)		
Parameters	D_6_01	D_7_01	D_8_01	D_6_02	D_7_02	D_8_02
β_0	1.1369	-1.1365	**-1.5799**	1.5903	0.0054	**-11.5812**
	(0.9434)	(0.5450)	(0.6874)	(2.2526)	(3.1738)	(4.6136)
β_1	0.8629	**3.4592**	**4.1291**	-0.1253	2.8252	**14.8557**
	(0.8491)	(0.5714)	(0.5241)	(2.3001)	(3.2644)	(4.8581)
β_2	0.1649	0.3324	0.2491	-0.0374	**0.3308**	**0.4470**
	(0.2649)	(0.1634)	(0.1972)	(0.1720)	(0.1579)	(0.1474)
β_3	**0.6153**	**0.7651**	**0.6510**	0.0794	**0.5187**	**0.5472**
	(0.2404)	(0.1361)	(0.1445)	(0.1068)	(0.1006)	(0.0959)
β_4	**0.4080**	**0.2637**	**0.4289**	**0.3587**	**0.4088**	**0.3126**
	(0.1541)	(0.0921)	(0.1162)	(0.1154)	(0.1104)	(0.1005)
β_5	0.2486	0.2412	0.2195	**0.4138**	0.0058	-0.0422
	(0.2143)	(0.1199)	(0.1565)	(0.1682)	(0.1332)	(0.1404)
R^2	0.9304	0.9683	0.9637	0.8384	0.9240	0.9337
SSE	0.2742	0.1145	0.2106	0.4465	0.3710	0.3160
DFE	12	13	14	22	22	22

The numbers in parentheses are standard deviations and the estimated coefficients are bold if P-values < 0.05. DFE measures the degrees of freedom.

Table 3. Regression Results for the Forward Price Ratio in Winter Months

	Delivery Date (Winter 2002)		
Parameters	D_1_02	D_2_02	D_3_02
β_0	0.4432	0.1770	0.2934
	(0.3995)	(0.4864)	(0.6244)
β_1	0.7183	0.9746	0.8579
	(0.4814)	(0.5891)	(0.8177)
β_2	-0.1535	-0.1676	-0.0466
	(0.1200)	(0.1450)	(0.1944)
β_3	0.1032	0.0669	0.0378
	(0.0784)	(0.0923)	(0.1612)
β_4	**0.2472**	**0.3082**	**0.3499**
	(0.0759)	(0.0962)	(0.1217)
β_5	**0.4988**	**0.4967**	0.4907
	(0.1287)	(0.1459)	(0.2436)
R^2	0.9287	0.9042	0.8587
SSE	0.1752	0.2856	0.4977
DFE	19	20	21

The numbers in parentheses are standard deviations and the estimated coefficients are bold if P-values < 0.05. DFE measures the degrees of freedom.

Separate models were estimated for each delivery month from June 2001 to August 2002. The models for all delivery months are summarized in Appendix B, and the following discussion is limited to the summer months (Table 2) and winter months (Table 3). In general, the models fit the data very well and the statistical properties are sound, particularly for delivery in the summer months. All of the $\boldsymbol{R^2}$ are greater than 84% and most models have a $\boldsymbol{R^2}$ greater than 90%. In Table 2, the price shocks for both electricity and natural gas explain the observed changes in the forward price ratios for summer months. Except for June 2002, the coefficient for electricity after the soft-cap auction was introduced (β_3) is the largest among the three price shocks for the summer months. In Table 3, conditions for the winter months are different, and the price shocks for natural gas have the biggest effect. The price shocks for electricity after the soft-cap auction (β_3) are smaller and are not statistically significant. The price shocks for electricity before the soft-cap auction (β_2) have small negative coefficients and are also not statistically significant.

The overall conclusion is that the price shocks for natural gas have consistent effects on the risk premium for electricity delivered in both summer and winter months. The corresponding effects of the conditional price shocks for electricity are small in the winter months and large in the summer months. Although additional restrictions could be placed on the models to eliminate incorrect signs, our current research is investigating how to combine all delivery months into a single model using new data for the daily quotations of the forward prices. We anticipate that the results using daily data will provide even stronger statistical evidence for the relationship between price shocks in the spot markets and the forward prices of electricity.

One final issue concerns the use of natural gas prices at Henry Hub in the model. Basic economics suggests that it would be better to use prices for delivery at a location in California. Generally, the prices of natural gas at different locations are highly correlated (see FERC, 2002). However, the typical historical relationship between the reported prices for California and the prices at Henry Hub did not hold during the winter of 2001, and the reported prices in California were substantially higher than the already high prices at Henry Hub. The report by FERC staff has raised serious doubts about the accuracy of these reported price data for California. The FERC staff shows, for example, how "wash trades" between two affiliated companies were used to distort the reported prices in California.

Adding the ratio of spot prices of natural gas at Southern California to Henry Hub (in logarithms, with a coefficient β_6) to the model in [3] does not improve the fit of the model significantly. A special case of this augmented model corresponds to replacing the price at Henry Hub by the price at Southern California $(\beta_4 = \beta_6)$. However, most of the estimates of β_6 are small and have the wrong sign for this special case (i.e. $\beta_6 < 0$). None of the estimates of β_6 are statistically significant. For the sample period used in this analysis, we conclude that the price of natural gas at Henry Hub was actually a better source of price discovery for traders than the reported price in California. Under normal conditions, the choice of which price to use for natural gas would not matter because the prices at the two locations would be so highly correlated.

5. Measuring the Cost of the Market Dysfunction

The results in the previous section show that the cumulative price shocks in the spot markets for both electricity and natural gas explained the high forward prices of electricity when the market was dysfunctional. The objective of this section is to use the models estimated in Section 3 to determine 1) the size of the risk premium in the forward market for electricity, and 2) the levels of "mitigated" prices without the risk premium. The high risk premiums and the corresponding high forward prices are, in effect, the cost of the market dysfunction in California to customers in the WECC. The results in this section strengthen the general conclusions in Section 3, and show that this cost to customers was much higher in the winter of 2001 than in the summer of 2000.

The sizes of the different price shocks and their corresponding coefficients contribute to the size of the risk premium in the forward market for electricity. Since the basic model in [3] is dynamic and the estimated rates of adjustment (β_5) vary by the month of delivery, the risk premium is defined as the long-run effect of the price shocks. For trading month t, this can be written:

$$\text{Risk Premium} = Exp[\beta_2 D_1 PelS_t + \beta_3 (1 - D_1) PelS_t + \beta_4 PngS_t)/(1 - \beta_5)] \qquad [4]$$

The risk premiums for delivery in two summer months (from Table 2) and one winter month (from Table 3) are shown in Figure 13, and they measure the percentage increase in the forward price of electricity for different trading dates. The risk premiums for delivery in July 2001 are over 400% during the winter of 2001, and over 150% for delivery in July 2002. The risk premiums are smaller for delivery in February 2002 but are still close to 100%. Figure 13 shows clearly the difference between the relatively small risk premiums during the first period of the market dysfunction in the summer of 2000 and the extremely high risk premiums during the second period of the market dysfunction in the winter of 2001. The risk premiums were much higher after the FERC intervened in the CAISO market and introduced new auction rules in this market. The economic logic is that the high spot prices of electricity in the winter, when prices are usually low, were a sign that conditions for buyers in the spot market would be much worse during the next summer, when prices are usually twice as high (see Figure 5). The risk premiums fell back to zero when a hard-price cap was finally imposed by the FERC in June 2001 on the WECC (see Figure 1).

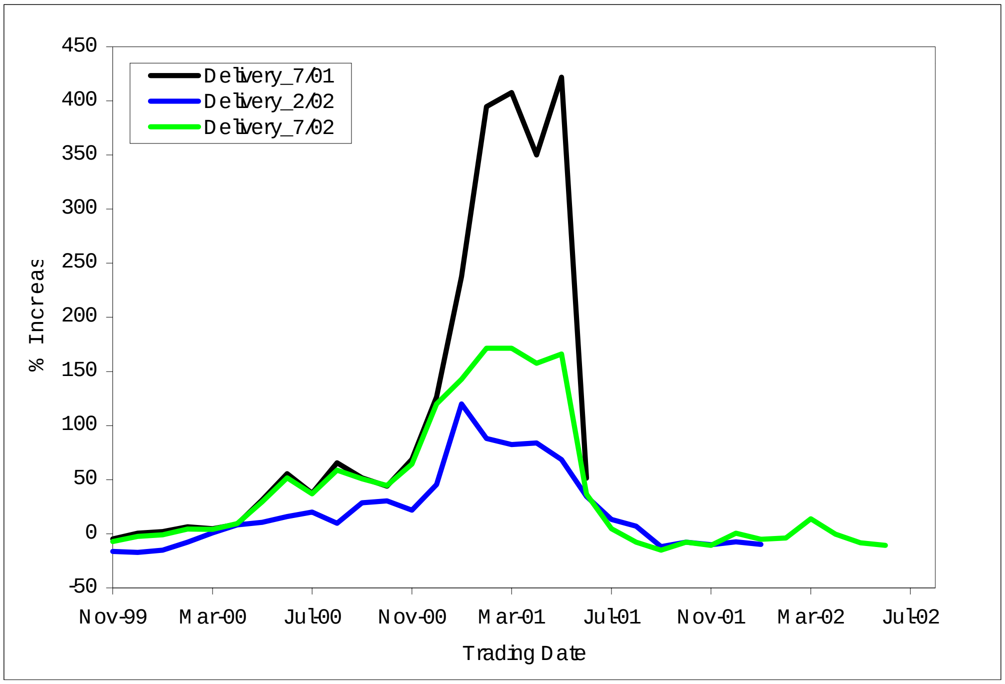

Figure 13: Risk Premiums for the Forward Price of Electricity due to Price Shocks in the Spot Markets for Electricity and Natural Gas

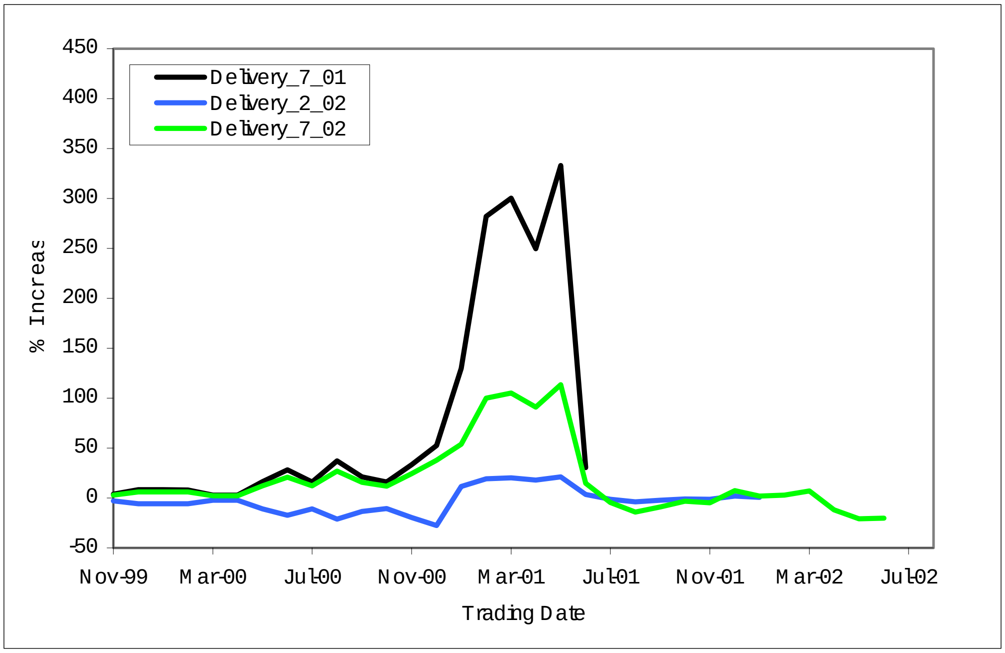

Figure 14: Risk Premiums for the Forward Price of Electricity due to Price Shocks in the Spot Market for Electricity Only

The risk premiums for the three delivery months shown in Figure 13 were recalculated using the conditional price shocks for electricity only (i.e., setting $\beta_4 = 0$ in [4]). These revised risk premiums are shown in Figure 14. Comparing Figures 13 and 14 provides additional insight into the sources of risk. The price shocks for electricity in Figure 14 were the dominant source of risk for delivery in the summer months but had only a minor effect for delivery in the winter months. In contrast, the price shocks for natural gas increased risk consistently for all delivery months. These results give a more complete explanation of the sources of risk than the general conclusions reached in Section 3 (all of the risk was attributed implicitly to the spot market for electricity in Section 3).

The risk premiums shown in Figure 13 illustrate the cumulative effects of the persistently positive price shocks in the spot markets for electricity and natural gas on the forward prices of electricity. Under normal conditions, these price shocks would vary around zero, and the forward prices would follow the typical seasonal patterns shown in Figure 5. However, prices for natural gas at Henry Hub were much higher than normal when the market for electricity was dysfunctional (see Figure 11). Given these higher prices for natural gas, prices for electricity would also be higher under normal conditions. It is possible to use [1] to predict the forward prices of electricity for different trading dates, and at the same time, to account for the current prices of natural gas and the typical annual changes in production costs of the marginal generator. This is equivalent to setting the risk premiums for electricity to zero, and it provides a way to determine "mitigated" forward prices for electricity for any selected trading month. The differences between the actual forward prices and the mitigated forward prices measure the cost of the market dysfunction.

The mitigated forward prices for electricity were computed as follows:

$$MFEL_{t,T} = Exp\left(\hat{FR}_T\right) \times FNG_{t,T} \qquad [5]$$

where

$MFEL_{t,T}$: mitigated forward price of electricity for delivery month T on trading month t

$\hat{FR}_T$: forward price ratio of electricity to natural gas predicted in [1] for delivery month T

$FNG_{t,T}$: actual forward price of natural gas for delivery month T on trading month t

The actual forward curves and mitigated forward curves are shown for twelve different trading dates in Figure 15. (The vertical scale is price, 0 – 700 \$/MWh; the horizontal scale is the delivery month, March 2000 to August 2002; and the trading date is given in the top right-hand corner.) The mitigated prices are lower than, but still relatively close to, the actual prices in the summer and fall of 2000 (first column of Figure 15). These trading dates correspond to the first period of dysfunction in the spot market before the FERC intervened in the CAISO market. In contrast, the actual prices

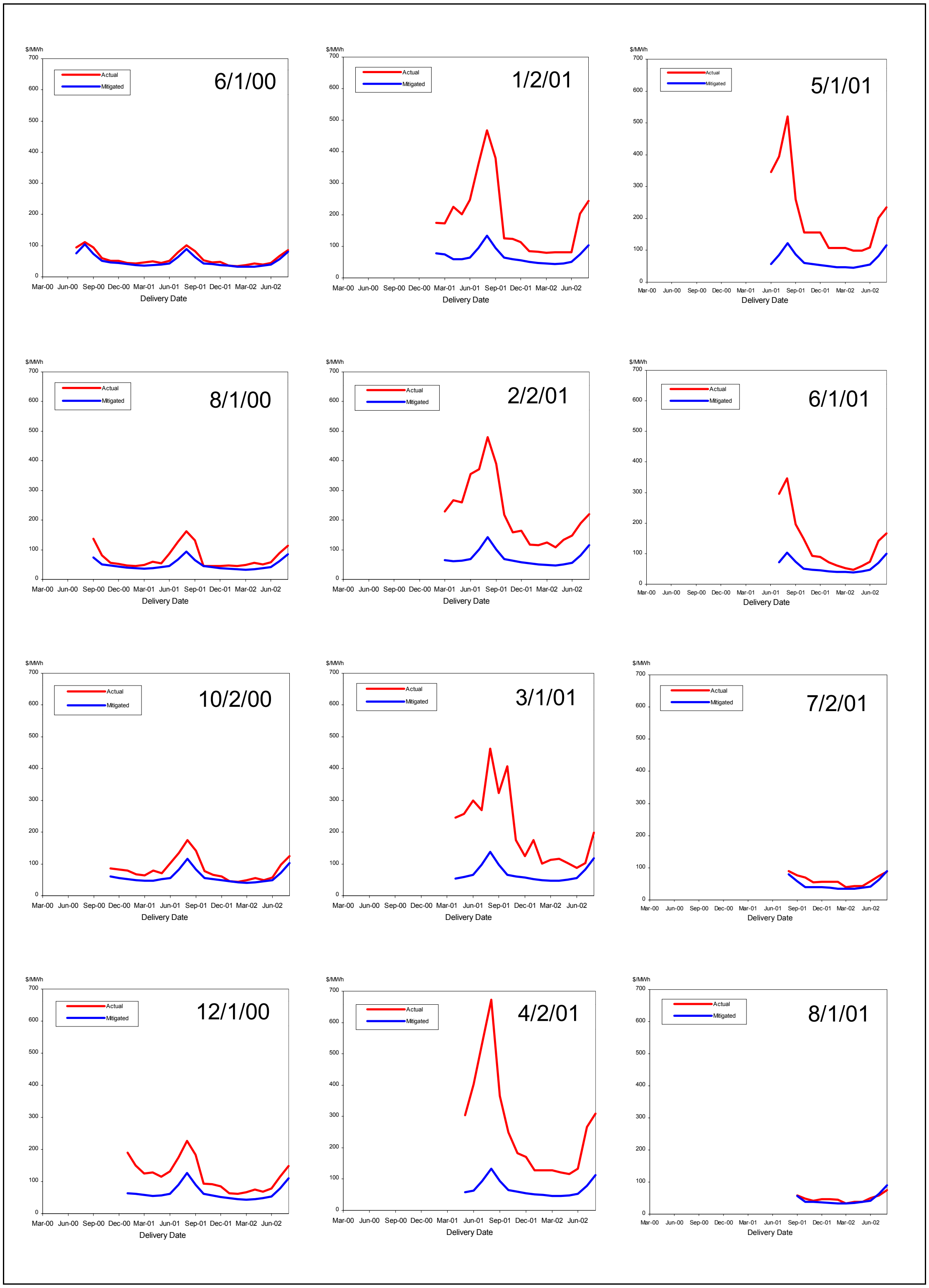

Figure 15: The Actual and Mitigated Forward Prices of Electricity at Palo Verde on Specified Trading Dates

are much higher than the mitigated prices during the winter and spring of 2001 (middle column of Figure 15). The actual forward price quoted on 4/2/01 for delivery in August 2001 is $672/MWh compared to a mitigated price of $134/MWh (the latter price is still high compared to historical levels). During the second period of dysfunction, the effects of the high prices of natural gas on production costs are dwarfed by the risk premiums on the forward prices of electricity (the mitigated prices are actually substantially higher in the winter of 2001 than the corresponding prices in the summer of 2000). The actual and mitigated prices are relatively low and almost identical to each other after the market dysfunction was corrected in the summer of 2001 (third column of Figure 15).

The high forward prices of electricity experienced in the winter and spring of 2001 were unprecedented. Under normal conditions, a forward price of $672/MWh for electricity delivered in the summer of 2001 would correspond to a price of $26/MMBtu for natural gas at Henry Hub using the price ratio in [1]. The actual forward price for natural gas quoted on 4/2/01 for delivery in August 2001 was only $5/MMBtu, corresponding to a price of $134/MWh for electricity under normal conditions. The overwhelming conclusion is that the relatively high prices of natural gas in the winter of 2001 only account for a small part of the increase in the forward prices of electricity. The risk premiums associated with the dysfunctional spot market in California were the primary cause of the high forward prices.

6. Summary and Conclusions

The econometric analyses in this paper lead to two major conclusions. First, the spot prices at different hubs in the Western Interconnection (or WECC) are highly interrelated (Section 2). Consequently, the problem of high spot prices in California when the market was dysfunctional was transferred almost immediately to other trading hubs. In addition, the effects of structural changes in the CAISO market, associated with regulatory intervention by the FERC, were reflected by similar changes in spot prices at all trading hubs. The effects were not limited to the central market in California. Second, the high spot prices resulted in high forward prices due to high risk premiums when the market in California was dysfunctional (Section 4). In this respect, the FERC made a big problem into a huge problem by failing to reestablish just and reasonable prices in California when the problem of high prices was first evaluated in the fall of 2000. After intervening in the CAISO market in December 2000, spot prices were allowed to remain at high levels that were truly unprecedented. Prices did not return to normal levels until the summer of 2001. Both of these specific conclusions support the general conclusion that “The California energy crisis was not a market failure, but a regulatory failure” (Wolak, 2003a, p. 2).

The close relationships among spot prices of electricity at different locations in a market are not a surprise to economists. Traders look for arbitrage opportunities in an active market. As soon as high prices for electricity were seen in California, efforts were made by suppliers in other locations to get in on the action. Eventually, farmers in Idaho decided it was more profitable to transfer irrigation water to hydro power rather than to grow potatoes; aluminum producers decided it was more profitable to sell their allocation of power from Bonneville than to produce aluminum; and BC Hydro wheeled surplus power to California to earn profits from the high prices. In fact, residential customers in British Columbia, who received rebate checks from their regulated utility, may be the only ones so far to benefit from deregulation in California. The WECC is a single market. Transmission capacity limits the interdependencies between the WECC and other regions further east. However, only Texas, by design, can operate independently of other markets.

Treating the WECC as a single market would not be a surprise to engineers. All generators from Canada to Mexico must be closely synchronized to ensure that the supply system is reliable. Small perturbations in one location are transferred instantaneously by the laws of physics to other locations. Surges in voltage can travel hundreds of kilometers in a few seconds like waves on an ocean. The WECC is a single supply system. Isolating California from the rest of the WECC would require physical intervention by system operators by, for example, throwing switches to take transmission lines out of service.

The econometric results in Section 2 confirm that spot prices at different locations in the WECC are highly interdependent. A second order VAR model was estimated using the spot prices at Mid-Columbia, the California-Oregon-Border (COB), Mead and Palo Verde. The model shows that these four locations share a common dynamic structure and exhibit the same upward shift in prices associated with the intervention by the FERC in the CAISO market. A second VAR model was estimated using spot prices at COB, Northern California, Southern California and the California Power Exchange (CAPX). These four locations also share a common dynamic structure, but, due to data limitations for the CAPX, this model only uses prices before the FERC intervention, and consequently, the effects of this intervention were not estimated. For the VAR analysis, the number of different locations specified in a model was limited by collinearity because the spot prices at different locations in the WECC are so highly correlated.

In spite of the overwhelming evidence from economic and engineering principles and econometric analyses such as the one shown in Section 2, the FERC has not yet ruled that the WECC is a single market. Initial decisions by the Administrative Law Judges (ALJ) at the FERC in hearings on rebates are limiting the enforcement of just and reasonable rates to customers in California. Customers in the Pacific Northwest will not be protected in the same way unless the FERC rules otherwise.

Although the consequences of high spot prices in the WECC were serious for buyers, the resulting consequences in the forward market were truly catastrophic. However, public data on forward prices are very limited, and it was fortunate for this analysis that a set of forward prices at Palo Verde was provided by Utility A. Since the behavior of forward prices has not been discussed in the literature as much as the behavior of spot prices, Section 3 provides a descriptive analysis of how forward price curves at Palo Verde changed when the spot market was dysfunctional.

Under normal conditions, the forward prices for electricity exhibit a strong seasonal pattern relative to the corresponding price of natural gas. Prices in the summer are about 25 times the price of natural gas, and fall to about 10 times in the winter. This substantial seasonal swing in the price ratio reflects the change in production costs associated with the use of generators with high heat rates and high emission rates in the summer.

During the market dysfunction, the ratio of forward prices for electricity to natural gas departed from normal seasonal patterns. The price ratio increased to well over 50 in the winter of 2001, five times the normal level. This happened in spite of the fact that the spot prices of natural gas were also much higher than historical levels and over twice as high as they had been in the summer of 2000. The forward price ratios remained at abnormally high levels through the winter and spring of 2001, and then fell rapidly back to normal levels in the summer of 2001. This return to normal levels coincided with the imposition of a price cap on all spot prices in the WECC by the FERC. Since that time, spot and forward prices have remained at normal levels relative to the price of natural gas.

Economic principles imply that forward prices should equal the expected spot price for a specific delivery date plus a premium for risk. However, the risk faced by buyers and sellers in a deregulated electricity market are very asymmetric. In effect, owners of generators hold call options because they are not obligated to generate if the spot price is lower than their operating cost. Deregulated markets do not guarantee that suppliers will earn an adequate rate of return on capital, but operating losses are limited. In contrast, buyers with an obligation to serve load (i.e. the incumbent utilities) have no such protection. In the winter of 2001, there seemed to be no limit on how high spot prices could go. Utilities were buying power at $300/MWh and receiving less than half of that price from their customers, who were still paying regulated rates. Under these adverse circumstances, buyers were willing to pay high risk premiums in forward contracts to stabilize the cost of their purchases.

The intervention by the FERC in the CAISO market exacerbated the problem of risk for buyers. The change in market rules implemented in December 2000 did not put an effective cap on prices. Suppliers were allowed to justify offers above a “soft” price cap of $150/MWh on the basis of production costs. The reaction of suppliers to this policy would not have been a surprise to federal regulators if they had listened to the concerns raised by the state regulators in California (Wolak, 2003a). The FERC rules encouraged suppliers to use expensive generators, and as a result, added the problem of production inefficiencies to the problem of market power. In addition, efforts were made by suppliers to exaggerate the reported costs of input factors such as natural gas and emission permits in California. In essence, the FERC had identified in November 2000 that there was a serious “meltdown” in the California spot market and had promised to do more than “offer short-term or band-aid solutions” to lower prices (FERC, 2000). The actual results of the FERC intervention were very different. Spot prices immediately increased and remained at unprecedented high levels for almost six months. This situation effectively created a state of panic among buyers in the market. It did not appear that the FERC was willing or able to fulfill the mandated role of ensuring that wholesale prices should be just and reasonable.

The econometric analysis in Section 4 estimated the relationship between spot prices and forward prices at Palo Verde when the market was dysfunctional. The important explanatory variables are the price shocks for electricity and natural gas. These price shocks were specified as the difference between the actual spot price and the "normal" spot price anticipated in the forward markets before the market dysfunction occurred. For electricity, the price shocks are conditional on the current spot price of natural gas (i.e. they account for the high price of natural gas in the winter of 2001). The price shocks for natural gas measure the uncertainty about the supply of the primary fuel for generating electricity. The price shocks for electricity measure the uncertainty about the performance of the spot market. Under normal conditions, the price shocks would vary around zero, but they were persistently positive from May 2000 to June 2001. The cumulative effect of both types of price shock explained roughly 90% of the variability of the forward price ratio for different delivery months from June 2001 to August 2001.

The effects of the price shocks for natural gas on the forward price of electricity were moderately high for all delivery months. In contrast, the price shocks for electricity, particularly for the period after the intervention by the FERC, resulted in major increases of forward prices for delivery in summer months. Since the new FERC rules had failed to control spot prices, buyers assumed that the bad market conditions in the winter would be even worse in the following summers when spot prices are normally high. The inability of regulators to lower spot prices in the winter of 2001 increased the uncertainty faced by buyers in the spot market, and as a result, risk premiums in the forward market were extremely high. The problems of high prices in the dysfunctional spot market were transferred to the forward market. To a large extent, the responsibility for this happening can be attributed to the inability of the FERC to act decisively in the fall of 2000 and bring wholesale prices down to just and reasonable levels.

An additional issue in the econometric analysis of forward prices is the use of prices at Henry Hub for natural gas. Economic principles imply that it would be preferable to use the price for a location in California. The problem with doing this is that it requires replacing the prices from an established exchange (NYMEx) with over-the-counter prices for bilateral trades reported by traders. There is a substantial amount of evidence, for the reasons explained earlier, that these prices were exaggerated (FERC, 2002). Adding the price of natural gas for Southern California to the model does not improve the fit. The conclusion is that the price from a reputable market at Henry Hub was a better source of price discovery for natural gas. The reported prices in California provided another source of uncertainty for buyers.

The econometric results in Section 4 were further elaborated in Section 5 to show the effects of the dysfunctional spot market in California on forward prices. Since the expected price shocks should be zero under normal conditions, the effects of the persistently positive price shocks provide estimates of the risk premium paid for electricity. The results in Figure 13 show very clearly how the risk premium changed while the market was dysfunctional. The risk premiums were relatively small until the intervention by the FERC in the CAISO market. From December 2000 to May 2001, risk premiums for delivery in the following two summers were very high, due primarily to the price shocks for electricity. The risk premiums for delivery in the winter of 2002 were smaller, due primarily to the price shocks for natural gas. In June 2001, the risk premiums had dropped back to zero. The high risk premiums in the winter and spring of 2001 should be called the FERC effect.

The second part of Section 5 estimated the "mitigated" prices of electricity using the actual prices of natural gas and the normal seasonal pattern of price ratios, estimated in Section 4. The actual and mitigated forward prices are shown in Figure 15 for different trading dates. Once again, the effects of risk are relatively small until December 2000. The actual forward prices are much higher than the mitigated prices from January to May 2001. By August 2001, the two forward curves are almost identical.

The method used to compute the mitigated forward prices of electricity is based on trustworthy price data for natural gas at Henry Hub. Hence, this method provides a reliable way to determine the "fair" prices in forward contracts for different trading dates. Since the prices of natural gas were high in the winter of 2001, the mitigated prices of electricity were also higher than historical levels, but not nearly as high as the actual forward prices.

Since the spot prices of both electricity and natural gas were high in the winter of 2001, it is interesting to consider why the forward markets behaved so differently. One possible explanation is the existence of an established exchange like NYMEx for natural gas. For electricity, Enron-On-Line (EOL) was a major source of price discovery and these prices may have been manipulated (FERC, 2002). For natural gas, prices were expected to drop by the summer. For electricity, however, the prices in the summer were expected to go even higher. This possibility created a frightening prospect for buyers that was not resolved until June 2001. By this time, most forward contracts for electricity had been signed. The basic choice faced by buyers was to pay the high spot prices now or pay on the installment plan in a forward contract.

Unfortunately for customers in the WECC, the FERC is the only regulatory organization with the authority to require that forward contracts should be renegotiated. Hence, the FERC is in the position of ruling on a problem that they helped to create. The current recommendations of the ALJ at the FERC are that forward contracts are not covered by the just and reasonable standard due to the Mobile-Sierra decisions of the Supreme Court in the nineteen fifties. A much higher standard of damage to the public interest is required to break a contract. When the FERC eventually rules on whether forward contracts should be renegotiated, we will see whose interests are being protected.

The Mobile-Sierra standard is a sensible standard in a fully regulated system because different utility service areas are effectively independent financial islands. The first lesson from the California energy crisis is that it was really a WECC energy crisis. All states in the WECC were adversely affected. This is an important feature of any deregulated market. It is virtually impossible to contain high prices in only one location. The problem spreads rapidly to all locations until physical transmission constraints or regulated regions are reached. The conclusion is that the Mobile-Sierra standard should be replaced by a new standard for deregulated markets.

The second lesson from the California energy crisis is that bad regulation can make matters worse. The intervention by the FERC in the CAISO market turned a crisis into a catastrophe. New and better procedures are needed to determine when and how the FERC should intervene in a deregulated market. The ambivalent role of the FERC in the California energy crisis has undermined the credibility of deregulation. As Bushnell argues (2003), regulators are now more concerned about getting acceptable market outcomes rather than setting rules to make a market perform competitively. This is a bad direction for regulation to take. For example, the success of mitigation in the northeast on reducing the number of price spikes in the spot markets has resulted in a shortage of new generating capacity. Elaborate and expensive ways of solving this new problem are now being evaluated. Without a clear policy from the FERC on how to prevent a crisis from becoming a catastrophe in the future, the slide back to virtual regulation is likely to continue. At the present time, the uncertainty faced by the public in a deregulated market is very asymmetric. While there is a potential for modest reductions in prices, if things go wrong, the sky is the limit.

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APPENDIX A

TABLE 1: SAS Output for the First Stage Models

PALO VERDE

The REG Procedure — Dependent Variable: logpv

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	11	602.80938	54.80085	218.60	<.0001
Error	1327	332.67001	0.25069		
Corrected Total	1338	935.47939			

Root MSE	0.50069	R-Square	0.6444
Dependent Mean	3.88152	Adj R-Sq	0.6414
Coeff Var	12.89938		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	3.86769	0.02086	185.45	<.0001
D2	1	1.77859	0.04682	37.98	<.0001
T2	1	0.55596	0.42374	1.31	0.1897
D3	1	-0.42490	0.03085	-13.77	<.0001
T3	1	2.81280	0.40748	6.90	<.0001
D_Sa	1	-0.10284	0.03961	-2.60	0.0095
D_Su	1	-0.41834	0.03971	-10.53	<.0001
D_Ho	1	-0.51943	0.11091	-4.68	<.0001
s_year	1	-0.30977	0.02075	-14.93	<.0001
s_hyear	1	0.00719	0.01947	0.37	0.7122
c_year	1	-0.29722	0.01986	-14.97	<.0001
c_hyear	1	0.06183	0.01984	3.12	0.0019

MID-COLUMBIA

Dependent Variable: logmid_col

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	11	944.78268	85.88933	195.27	<.0001
Error	1327	583.67397	0.43984		
Corrected Total	1338	1528.45664			

Root MSE	0.66321	R-Square	0.6181
Dependent Mean	3.76036	Adj R-Sq	0.6150
Coeff Var	17.63681		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	3.73854	0.02763	135.33	<.0001
D2	1	2.19141	0.06202	35.33	<.0001
T2	1	1.54739	0.56127	2.76	0.0059
D3	1	-0.60567	0.04087	-14.82	<.0001
T3	1	4.07980	0.53974	7.56	<.0001
D_Sa	1	-0.12311	0.05247	-2.35	0.0191
D_Su	1	-0.25354	0.05260	-4.82	<.0001
D_Ho	1	-0.36501	0.14691	-2.48	0.0131
s_year	1	-0.40118	0.02748	-14.60	<.0001
s_hyear	1	-0.04979	0.02580	-1.93	0.0538
c_year	1	-0.09954	0.02631	-3.78	0.0002
c_hyear	1	-0.07824	0.02628	-2.98	0.0030

MEAD

Dependent Variable: logmead

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	11	616.61058	56.05551	217.12	<.0001
Error	1327	342.59825	0.25818		
Corrected Total	1338	959.20883			

Root MSE	0.50811	R-Square	0.6428
Dependent Mean	3.92105	Adj R-Sq	0.6399
Coeff Var	12.95849		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	3.89602	0.02117	184.08	<.0001
D2	1	1.81682	0.04752	38.23	<.0001
T2	1	0.54638	0.43001	1.27	0.2041
D3	1	-0.41678	0.03131	-13.31	<.0001

T3	1	2.74286	0.41351	6.63	<.0001
D_Sa	1	-0.09697	0.04020	-2.41	0.0160
D_Su	1	-0.39779	0.04030	-9.87	<.0001
D_Ho	1	-0.52111	0.11255	-4.63	<.0001
s_year	1	-0.31046	0.02105	-14.75	<.0001
s_hyear	1	0.00609	0.01976	0.31	0.7579
c_year	1	-0.29673	0.02015	-14.72	<.0001
c_hyear	1	0.07096	0.02013	3.52	0.0004

CALIFORNIA OREGON BORDER

Dependent Variable: **logcob**

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	11	820.38037	74.58003	236.02	<.0001
Error	1327	419.31645	0.31599		
Corrected Total	1338	1239.69682			

Root MSE	0.56213	R-Square	0.6618
Dependent Mean	3.87875	Adj R-Sq	0.6590
Coeff Var	14.49251		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	3.84920	0.02342	164.39	<.0001
D2	1	2.08612	0.05257	39.68	<.0001
T2	1	1.30300	0.47573	2.74	0.0062
D3	1	-0.53608	0.03464	-15.48	<.0001
T3	1	3.18953	0.45748	6.97	<.0001
D_Sa	1	-0.10415	0.04447	-2.34	0.0193
D_Su	1	-0.28922	0.04458	-6.49	<.0001
D_Ho	1	-0.36220	0.12452	-2.91	0.0037
s_year	1	-0.37665	0.02329	-16.17	<.0001
s_hyear	1	-0.04936	0.02186	-2.26	0.0241
c_year	1	-0.16570	0.02230	-7.43	<.0001
c_hyear	1	0.00042807	0.02228	0.02	0.9847

SOUTHERN CALIFORNIA

Dependent Variable: **logs_cal**

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	11	585.59320	53.23575	214.99	<.0001
Error	1327	328.59164	0.24762		
Corrected Total	1338	914.18484			

Root MSE	0.49761	R-Square	0.6406
Dependent Mean	3.88031	Adj R-Sq	0.6376
Coeff Var	12.82409		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	3.85483	0.02073	185.97	<.0001
D2	1	1.79107	0.04654	38.49	<.0001
T2	1	0.56605	0.42113	1.34	0.1791
D3	1	-0.40980	0.03066	-13.36	<.0001
T3	1	2.48882	0.40497	6.15	<.0001
D_Sa	1	-0.09925	0.03937	-2.52	0.0118
D_Su	1	-0.36668	0.03947	-9.29	<.0001
D_Ho	1	-0.43295	0.11023	-3.93	<.0001
s_year	1	-0.29796	0.02062	-14.45	<.0001
s_hyear	1	-0.01896	0.01935	-0.98	0.3275
c_year	1	-0.23271	0.01974	-11.79	<.0001
c_hyear	1	0.04705	0.01972	2.39	0.0172

NORTHERN CALIFORNIA

Dependent Variable: **logn_cal**

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	11	689.35928	62.66903	248.56	<.0001
Error	1327	334.57128	0.25213		
Corrected Total	1338	1023.93056			

Root MSE	0.50212	R-Square	0.6732
Dependent Mean	3.90368	Adj R-Sq	0.6705
Coeff Var	12.86278		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	3.85723	0.02092	184.42	<.0001
D2	1	1.98554	0.04696	42.28	<.0001
T2	1	0.31126	0.42495	0.73	0.4640
D3	1	-0.42595	0.03094	-13.77	<.0001
T3	1	2.85074	0.40864	6.98	<.0001
D_Sa	1	-0.09534	0.03973	-2.40	0.0165
D_Su	1	-0.31507	0.03983	-7.91	<.0001
D_Ho	1	-0.38490	0.11123	-3.46	0.0006
s_year	1	-0.36784	0.02081	-17.68	<.0001
s_hyear	1	-0.05694	0.01953	-2.92	0.0036
c_year	1	-0.17657	0.01992	-8.87	<.0001
c_hyear	1	0.02486	0.01990	1.25	0.2118

CALIFORNIA POWER EXCHANGE

Dependent Variable: **logpx_ump**

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	7	147.76108	21.10873	56.40	<.0001
Error	699	261.61475	0.37427		
Corrected Total	706	409.37583			

Root MSE	0.61178	R-Square	0.3609
Dependent Mean	3.83500	Adj R-Sq	0.3545
Coeff Var	15.95244		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	3.90354	0.02744	142.24	<.0001
D_Sa	1	-0.22742	0.06669	-3.41	0.0007
D_Su	1	-0.22280	0.06669	-3.34	0.0009
D_Ho	1	-0.29677	0.18687	-1.59	0.1127
s_year	1	-0.58550	0.03209	-18.25	<.0001
s_hyear	1	-0.09998	0.03225	-3.10	0.0020
c_year	1	-0.17760	0.03316	-5.36	<.0001
c_hyear	1	0.01348	0.03312	0.41	0.6841

LEGEND

Explanatory Variables

D2	Dummy variable for the soft-cap period
T2	Inverse variable for the soft-cap period
D3	Dummy variable for the post soft-cap period
T3	Inverse variable for the post soft-cap period
D_Sa	Dummy variable for Saturdays
D_Su	Dummy variable for Sundays
D_Ho	Dummy variable for holidays
s_year	Sine wave with a period of one year
s_hyear	Sine wave with a period of half a year
c_year	Cosine wave with a period of one year
c_hyear	Cosine wave with a period of half a year

TABLE 2: SAS Output for the Second Stage VAR Models

Model A

The VARMAX Procedure

Number of Observations 1339
Number of Pairwise Missing 0

The VARMAX Procedure

Type of Model VAR(2)
Estimation Method Maximum Likelihood Estimation

Model Parameter Estimates

Equation	Parameter	Estimate	Std Error	T Ratio	Prob>|T|
r_pv(t)	AR1_1_1	0.53486	0.00280	190.93	0.0001
	AR1_1_2	0.02011	0.00391	5.14	0.0001
	AR1_1_3	0.07241	0.01065	6.80	0.0001
	AR1_1_4	0.12919	0.00640	20.17	0.0001
	AR2_1_1	0.23633	0.00591	39.96	0.0001
	AR2_1_2	-0.01305	0.00571	-2.29	0.0224
	AR2_1_3	-0.05814	0.01278	-4.55	0.0001
	AR2_1_4	-0.00421	0.00784	-0.54	0.5909
r_mid(t)	AR1_2_1	0.04712	0.00471	10.00	0.0001
	AR1_2_2	0.79315	0.00557	142.29	0.0001
	AR1_2_3	0.03908	0.00694	5.64	0.0001
	AR1_2_4	-0.06104	0.00689	-8.85	0.0001
	AR2_2_1	0.07873	0.00655	12.02	0.0001
	AR2_2_2	0.16108	0.00697	23.12	0.0001
	AR2_2_3	-0.10409	0.00631	-16.50	0.0001
	AR2_2_4	-0.01201	0.01082	-1.11	0.2672
r_mea(t)	AR1_3_1	0.30572	0.00519	58.92	0.0001
	AR1_3_2	-0.01239	0.00476	-2.60	0.0093
	AR1_3_3	0.31481	0.01026	30.67	0.0001
	AR1_3_4	0.14970	0.00679	22.06	0.0001
	AR2_3_1	0.12768	0.00657	19.44	0.0001
	AR2_3_2	-0.02110	0.00724	-2.91	0.0036
	AR2_3_3	0.06620	0.01118	5.92	0.0001
	AR2_3_4	0.00331	0.00842	0.39	0.6942
r_cob(t)	AR1_4_1	0.07697	0.00468	16.46	0.0001
	AR1_4_2	0.19904	0.00492	40.43	0.0001
	AR1_4_3	0.07704	0.00584	13.20	0.0001
	AR1_4_4	0.44439	0.00716	62.05	0.0001
	AR2_4_1	0.03815	0.00611	6.25	0.0001
	AR2_4_2	-0.07248	0.00621	-11.67	0.0001
	AR2_4_3	-0.05759	0.00665	-8.66	0.0001
	AR2_4_4	0.22840	0.01118	20.43	0.0001

Covariance Matrix for the Innovation

Variable	r_pv	r_mid_col	r_mead	r_cob
r_pv	0.03927	0.03640	0.03819	0.03536
r_mid_col	0.03640	0.06061	0.03589	0.04739
r_mead	0.03819	0.03589	0.04019	0.03512
r_cob	0.03536	0.04739	0.03512	0.04692

Model B

The VARMAX Procedure

Number of Observations 707
Number of Pairwise Missing 0

The VARMAX Procedure

Type of Model VAR(2)
Estimation Method Maximum Likelihood Estimation

Model Parameter Estimates

Equation	Parameter	Estimate	Std Error	T Ratio	Prob>|T|
r_cob(t)	AR1_1_1	0.68798	0.00411	167.44	0.0001
	AR1_1_2	0.13753	0.01061	12.96	0.0001
	AR1_1_3	-0.22405	0.01083	-20.70	0.0001
	AR1_1_4	0.40896	0.01081	37.84	0.0001
	AR2_1_1	0.20313	0.01055	19.25	0.0001
	AR2_1_2	-0.09562	0.01240	-7.71	0.0001

	AR2_1_3	0.18312	0.01340	13.66	0.0001
	AR2_1_4	-0.31465	0.01559	-20.18	0.0001
r_s_c(t)	AR1_2_1	0.24975	0.00600	41.65	0.0001
	AR1_2_2	0.45135	0.01012	44.58	0.0001
	AR1_2_3	-0.15277	0.01037	-14.74	0.0001
	AR1_2_4	0.42822	0.01364	31.41	0.0001
	AR2_2_1	-0.10714	0.01249	-8.58	0.0001
	AR2_2_2	0.16895	0.01341	12.60	0.0001
	AR2_2_3	0.23817	0.01609	14.80	0.0001
	AR2_2_4	-0.30894	0.01890	-16.34	0.0001
r_n_c(t)	AR1_3_1	0.37091	0.00632	58.70	0.0001
	AR1_3_2	0.13409	0.01015	13.22	0.0001
	AR1_3_3	0.07843	0.01112	7.05	0.0001
	AR1_3_4	0.36937	0.01171	31.53	0.0001
	AR2_3_1	-0.10749	0.01120	-9.60	0.0001
	AR2_3_2	-0.11248	0.01231	-9.13	0.0001
	AR2_3_3	0.50861	0.01649	30.84	0.0001
	AR2_3_4	-0.28820	0.01654	-17.42	0.0001
r_px_(t)	AR1_4_1	0.00910	0.00898	1.01	0.3111
	AR1_4_2	0.21521	0.01043	20.64	0.0001
	AR1_4_3	-0.10939	0.01155	-9.47	0.0001
	AR1_4_4	0.97015	0.01319	73.53	0.0001
	AR2_4_1	0.19433	0.01160	16.75	0.0001
	AR2_4_2	-0.10219	0.01393	-7.34	0.0001
	AR2_4_3	-0.02701	0.01319	-2.05	0.0410
	AR2_4_4	-0.21402	0.02701	-7.92	0.0001

Covariance Matrix for the Innovation

Variable	r_cob	r_s_cal	r_n_cal	r_px_ump
r_cob	0.03222	0.02444	0.02730	0.01888
r_s_cal	0.02444	0.03072	0.02277	0.01635
r_n_cal	0.02730	0.02277	0.02830	0.01839
r_px_ump	0.01888	0.01635	0.01839	0.03872

Appendix B

SAS Output for the Forward Price Ratio

Estimates of the Relationship of Price Shocks in the Spot Markets for Electricity and Natural Gas to the Ratio of the Forward Price of Electricity at Palo Verde to the Forward Price of Natural Gas at Henry Hub for Different Delivery Months
(Using the AUTOREG procedure in the Statistical Package SAS)

Structure of Model [3]

$$FR_{T,t} = \beta_0 + \left(1 - W_t\right) FRf_{T,t} + W_t\left(\beta_1 + \beta_2 D_1 PelS_{t-1} + \beta_3\left(1 - D_1\right) PelS_{t-1} + \beta_4 PngS_{t-1} + \beta_5 FR_{T,t-1}\right) + \varepsilon_t$$

where t = 1,2,…,T is the trading month

T is the delivery month

W_t: $= 1 - \frac{1}{(T - t + 1)^2}$ is a specified weight between 0 and 1

$FR_{T,t}$ is the logarithm of the ratio of the forward prices of electricity at Palo Verde to natural gas at Henry Hub traded on the first business day of month t for delivery in month T

$FRf_{T,t}$ is the forecast of $FR_{T,t}$ made on month t (lagged spot price ratio adjusted for seasonal effects)

D_1 is a dummy variable for months prior to the soft-cap auction

$PelS_t$ is the conditional price shock for electricity for month t (deseasonalized spot price ratio in logarithmic form)

$PngS_t$ is the price shock for natural gas for month t (deseasonalized spot price in logarithmic form)

Legend for Variables Used in the Regression Models

• Dependent Variable

DDmonth_yearR_A = $[FR_{T,t} - (1 - W_t) FRf_{T,t}]$ is the logarithm of the forward price ratio traded at t (adjusted for the weighted forecast at t) and T = month_year

• Explanatory Variables

Intercept

K = W_t

DSSel_D1_K = $PelS_{t-1} \times D_1 \times W_t$ is the weighted conditional price shocks for electricity before the soft-cap auction

DSSel_D2_K = $PelS_{t-1} \times (1-D_1) \times W_t$ is the weighted conditional price shocks for electricity after the soft-cap auction

DSSng_K = $PngS_{t-1} \times W_t$ is the weighted price shocks for natural gas

LagDDmonth_yearR_K = $FR_{T,t-1} \times W_t$ is the weighted logarithm of the forward price ratio traded at t-1, and T = month_year

Estimated Regression Models for Different Delivery Months

```
The AUTOREG Procedure
                    Dependent Variable    DD6_01R_A
                   Ordinary Least Squares Estimates

      SSE                 0.27417457    DFE                      12
      MSE                    0.02285    Root MSE            0.15116
      SBC                 -6.8944987    AIC              -12.236729
      Regress R-Square        0.9304    Total R-Square       0.9304
      Durbin-Watson           2.7291
```

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	1.1369	0.9434	1.21	0.2514
K	1	0.8629	0.8491	1.02	0.3296
DSSel_D1_K	1	0.1649	0.2649	0.62	0.5452
DSSel_D2_K	1	0.6153	0.2404	2.56	0.0250
DSSng_K	1	0.4080	0.1541	2.65	0.0213
lagDD6_01R_K	1	0.2486	0.2143	1.16	0.2687

Dependent Variable DD7_01R_A
Ordinary Least Squares Estimates

SSE	0.11453399	DFE	13
MSE	0.00881	Root MSE	0.09386
SBC	-25.528832	AIC	-31.195466
Regress R-Square	0.9683	Total R-Square	0.9683
Durbin-Watson	2.1673		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	-1.1365	0.5450	-2.09	0.0573
K	1	3.4592	0.5714	6.05	<.0001
DSSel_D1_K	1	0.3324	0.1634	2.03	0.0628
DSSel_D2_K	1	0.7651	0.1361	5.62	<.0001
DSSng_K	1	0.2637	0.0921	2.86	0.0134
lagDD7_01R_K	1	0.2412	0.1199	2.01	0.0655

Dependent Variable DD8_01R_A
Ordinary Least Squares Estimates

SSE	0.21061633	DFE	14
MSE	0.01504	Root MSE	0.12265
SBC	-16.337054	AIC	-22.311447
Regress R-Square	0.9637	Total R-Square	0.9637
Durbin-Watson	2.3137		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	-1.5799	0.6874	-2.30	0.0375
K	1	4.1291	0.5241	7.88	<.0001
DSSel_D1_K	1	0.2491	0.1972	1.26	0.2272
DSSel_D2_K	1	0.6510	0.1445	4.51	0.0005
DSSng_K	1	0.4289	0.1162	3.69	0.0024
lagDD8_01R_K	1	0.2195	0.1565	1.40	0.1826

Dependent Variable DD9_01R_A
Ordinary Least Squares Estimates

SSE	0.20405202	DFE	15
MSE	0.01360	Root MSE	0.11663
SBC	-19.449405	AIC	-25.716539
Regress R-Square	0.9594	Total R-Square	0.9594
Durbin-Watson	1.6517		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	-0.8390	0.4912	-1.71	0.1082
K	1	4.0435	0.6035	6.70	<.0001
DSSel_D1_K	1	0.0946	0.1764	0.54	0.5996
DSSel_D2_K	1	0.4529	0.1151	3.94	0.0013
DSSng_K	1	0.6728	0.1150	5.85	<.0001
lagDD9_01R_K	1	-0.0350	0.1425	-0.25	0.8093

Dependent Variable DD10_01R_A
Ordinary Least Squares Estimates

SSE	0.41536077	DFE	16
MSE	0.02596	Root MSE	0.16112
SBC	-6.3527555	AIC	-12.89901
Regress R-Square	0.9061	Total R-Square	0.9061
Durbin-Watson	3.3262		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	0.6233	0.7530	0.83	0.4200
K	1	1.5573	0.7521	2.07	0.0549
DSSel_D1_K	1	-0.1291	0.2352	-0.55	0.5906
DSSel_D2_K	1	0.4947	0.1562	3.17	0.0060

DSSng_K	1	0.2509	0.1340	1.87	0.0795
lagDD10_01R_K	1	0.1673	0.1705	0.98	0.3410

Dependent Variable DD11_01R_A
Ordinary Least Squares Estimates

SSE	0.31410004	DFE	17
MSE	0.01848	Root MSE	0.13593
SBC	-14.667235	AIC	-21.480201
Regress R-Square	0.9108	Total R-Square	0.9108
Durbin-Watson	1.6817		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	0.2208	0.5705	0.39	0.7036
K	1	1.7605	0.9106	1.93	0.0700
DSSel_D1_K	1	0.0261	0.1896	0.14	0.8923
DSSel_D2_K	1	0.3993	0.1719	2.32	0.0329
DSSng_K	1	0.1671	0.1082	1.55	0.1407
lagDD11_01R_K	1	0.2154	0.2673	0.81	0.4315

Dependent Variable DD12_01R_A
Ordinary Least Squares Estimates

SSE	0.36404785	DFE	18
MSE	0.02022	Root MSE	0.14221
SBC	-13.347198	AIC	-20.415521
Regress R-Square	0.8907	Total R-Square	0.8907
Durbin-Watson	2.8366		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	-0.1552	0.5889	-0.26	0.7951
K	1	2.8063	0.9294	3.02	0.0074
DSSel_D1_K	1	-0.1146	0.1886	-0.61	0.5510
DSSel_D2_K	1	0.4540	0.1524	2.98	0.0081
DSSng_K	1	0.2051	0.1124	1.82	0.0848
lagDD12_01R_K	1	-0.0476	0.2520	-0.19	0.8523

Dependent Variable DD1_02R_A
Ordinary Least Squares Estimates

SSE	0.17518793	DFE	19
MSE	0.00922	Root MSE	0.09602
SBC	-33.759114	AIC	-41.072369
Regress R-Square	0.9287	Total R-Square	0.9287
Durbin-Watson	1.7601		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	0.4432	0.3995	1.11	0.2812
K	1	0.7183	0.4814	1.49	0.1520
DSSel_D1_K	1	-0.1535	0.1200	-1.28	0.2164
DSSel_D2_K	1	0.1032	0.0784	1.32	0.2035
DSSng_K	1	0.2472	0.0759	3.26	0.0042
lagDD1_02R_K	1	0.4988	0.1287	3.87	0.0010

Dependent Variable DD2_02R_A
Ordinary Least Squares Estimates

SSE	0.28556657	DFE	20
MSE	0.01428	Root MSE	0.11949
SBC	-23.962409	AIC	-31.510989
Regress R-Square	0.9042	Total R-Square	0.9042
Durbin-Watson	1.9800		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	0.1770	0.4864	0.36	0.7198
K	1	0.9746	0.5891	1.65	0.1137
DSSel_D1_K	1	-0.1676	0.1450	-1.16	0.2614
DSSel_D2_K	1	0.0669	0.0923	0.73	0.4767
DSSng_K	1	0.3082	0.0962	3.20	0.0045
lagDD2_02R_K	1	0.4967	0.1459	3.40	0.0028

Dependent Variable DD3_02R_A

Ordinary Least Squares Estimates

SSE	0.49773496	DFE	21
MSE	0.02370	Root MSE	0.15395
SBC	-11.427457	AIC	-19.202479
Regress R-Square	0.8587	Total R-Square	0.8587
Durbin-Watson	1.5028		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	0.2934	0.6244	0.47	0.6433
K	1	0.8579	0.8177	1.05	0.3061
DSSel_D1_K	1	-0.0466	0.1944	-0.24	0.8128
DSSel_D2_K	1	0.0378	0.1612	0.23	0.8169
DSSng_K	1	0.3499	0.1217	2.87	0.0091
lagDD3_02R_K	1	0.4907	0.2436	2.01	0.0569

Dependent Variable DD4_02R_A
Ordinary Least Squares Estimates

SSE	0.53591589	DFE	22
MSE	0.02436	Root MSE	0.15608
SBC	-11.313727	AIC	-19.306954
Regress R-Square	0.8644	Total R-Square	0.8644
Durbin-Watson	1.6541		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	0.4718	0.6284	0.75	0.4607
K	1	0.6347	0.7557	0.84	0.4101
DSSel_D1_K	1	0.0705	0.1879	0.38	0.7112
DSSel_D2_K	1	0.006210	0.1229	0.05	0.9601
DSSng_K	1	0.3695	0.1326	2.79	0.0108
lagDD4_02R_K	1	0.5166	0.1899	2.72	0.0125

Dependent Variable DD5_02R_A
Ordinary Least Squares Estimates

SSE	0.42395879	DFE	22
MSE	0.01927	Root MSE	0.13882
SBC	-17.875274	AIC	-25.868501
Regress R-Square	0.8655	Total R-Square	0.8655
Durbin-Watson	1.9144		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	0.7619	1.2473	0.61	0.5476
K	1	0.8935	1.3518	0.66	0.5155
DSSel_D1_K	1	-0.0197	0.1659	-0.12	0.9064
DSSel_D2_K	1	0.1481	0.1187	1.25	0.2251
DSSng_K	1	0.3924	0.1136	3.45	0.0023
lagDD5_02R_K	1	0.2943	0.1907	1.54	0.1372

Dependent Variable DD6_02R_A
Ordinary Least Squares Estimates

SSE	0.44652021	DFE	22
MSE	0.02030	Root MSE	0.14247
SBC	-16.423518	AIC	-24.416746
Regress R-Square	0.8384	Total R-Square	0.8384
Durbin-Watson	2.3035		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	1.5903	2.2526	0.71	0.4876
K	1	-0.1253	2.3001	-0.05	0.9571
DSSel_D1_K	1	-0.0374	0.1720	-0.22	0.8301
DSSel_D2_K	1	0.0794	0.1068	0.74	0.4652
DSSng_K	1	0.3587	0.1154	3.11	0.0051
lagDD6_02R_K	1	0.4138	0.1682	2.46	0.0222

Dependent Variable DD7_02R_A
Ordinary Least Squares Estimates

SSE	0.37104177	DFE	22
MSE	0.01687	Root MSE	0.12987

SBC	-21.608279	AIC	-29.601506
Regress R-Square	0.9240	Total R-Square	0.9240
Durbin-Watson	1.5264		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	0.005410	3.1738	0.00	0.9987
K	1	2.8252	3.2644	0.87	0.3961
DSSel_D1_K	1	0.3308	0.1579	2.10	0.0478
DSSel_D2_K	1	0.5187	0.1006	5.15	<.0001
DSSng_K	1	0.4088	0.1104	3.70	0.0012
lagDD7_02R_K	1	0.005836	0.1332	0.04	0.9655

Dependent Variable DD8_02R_A

Ordinary Least Squares Estimates

SSE	0.31602176	DFE	22
MSE	0.01436	Root MSE	0.11985
SBC	-26.102379	AIC	-34.095606
Regress R-Square	0.9337	Total R-Square	0.9337
Durbin-Watson	1.6504		

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	-11.5812	4.6136	-2.51	0.0199
K	1	14.8557	4.8581	3.06	0.0058
DSSel_D1_K	1	0.4470	0.1474	3.03	0.0061
DSSel_D2_K	1	0.5472	0.0959	5.71	<.0001
DSSng_K	1	0.3126	0.1005	3.11	0.0051
lagDD8_02R_K	1	-0.0422	0.1404	-0.30	0.7663