

# Ex Ante and Ex Post Designs for Electric Market Mitigation: Past and Present Experience and Lessons from California

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## Abstract

*Restructuring in electric power sectors took a significant step backward in the summer of 2000 when wholesale and retail markets in California experienced staggering price increases that continued through June of 2001. During this period, California suppliers neared bankruptcy and one went into bankruptcy, as did the state's cornerstone market institution, the California Power Exchange. While the cause has been alternatively described as the "perfect storm" and "a case of market manipulation" the outcome has been a price mitigation process at the FERC, a series of federal and state lawsuits, and a California Market Design process led by the CA ISO that incorporates four separate proposals for statewide price mitigation.*

*The objective of this paper is to present an analysis of the impact of actual and proposed market mitigation procedures for the California market. Based on detailed analyses (10 minute California electric system operating data for the refund period of October 2000 through June 2001) the paper*

- *Reviews and critiques the FERC procedure for calculation of a Mitigation Market Clearing Price to be applied during the refund period,*
- *Evaluates market mitigation strategies that are being considered for future application in the State and the country as a whole, and*
- *Evaluates the possible success of any ex post price mitigation.*

*The analysis is focused on the impact of such strategies on wholesale electric market development both in the US and internationally. Recommendations are offered for FERC's ongoing Standard Market Design effort that will affect the design of electricity markets throughout the country.*

## 1. Introduction and Overview<sup>1</sup>

When the State of California Public Utility Commission (CPUC) initiated its restructuring process in 1992 that culminated in the publication of the "Blue Book" in 1994, it was anticipated that the resulting restructured electric market would correct any (and all) inefficiencies found in earlier models like the United Kingdom and so become the model for North America. The process quickly hit a series of hurdles that had long-term effects on the California market and repercussions in the process of restructuring throughout North America and probably all restructured electricity markets. While many of the lessons learned in California have been positive, if painful, the most critical lesson learned has yet to be internalized in market operations, specifically how to reset market prices if they are judged not to be, in the terms of the Federal Energy Regulatory Commission (FERC) mandate, "just and reasonable."<sup>2</sup>

The objective of this paper is to provide a detailed discussion of the logic of market price mitigation both *ex ante* and *ex post*. Our goal is to demonstrate, through the *ex post* example of the existing FERC docket (FERC 00-95-045), the futility and litigious nightmare of attempting to reset market prices so as to create refunds from multiple suppliers to multiple users. We then focus on the proposals for *ex ante* price mitigation procedures and analyze the proposals provided to the FERC and included within the Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR) released by the Commission on July 31, 2002.

<sup>1</sup> Both authors are participating as expert witnesses in the California Refund case (EL00-95-045) currently before the FERC

<sup>2</sup> Section 205(a) of the Federal Power Act states: "All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful."

## 2. California 2000-2001: Crisis in the Making

Leading up to the summer of 2000, California has been described as the analog of the Perfect Storm; you could not see all of the elements until it was too late to do anything about it. While this is true in part, it is equally true that there were multiple points at which more effective response would have lessened, if not eliminated the crisis.

There were many elements that contributed to the Perfect Storm that could have and should have been addressed by the CPUC and other state and political agencies. However there were some that were beyond the control of the CPUC. For example:

- Demand growth in the Southwest and California appeared to be nearly 8%, well above the 2.5% being used for planning purposes.
- The spring and summer of 2000 had average temperatures – and with them cooling loads – in the affluent Southwest the second or third highest of the 106 year history of data collection.
- Northwest (US and Canadian) hydro conditions were at the low end of their wet-dry cycle. Based on snow pack, in April 2001, it looked like the Columbia River flows were going to be the second driest since 1929.

On the other hand, the CPUC and the political process did have control over the following critical elements:

- Prices to consumers were capped while wholesale prices to load serving entities (the three IOUs) were not, leading to the bankruptcy of PG&E, and the near bankruptcy of Southern California Edison. SDG&E escaped because they had already paid off all of their stranded costs and thereby no longer had price caps.<sup>3</sup>
- No new generation had been built in California for nearly a decade while a number of older and dirtier units had been retired
- No significant additions to transmission into and within California had been constructed in a decade.
- No significant policies or programs to incorporate demand response into the market structure.

In addition, the structure of the California market, as codified on September 23, 1996 in California Law Assembly Bill 1890 and Senate Bill 90 (referred to as AB 1890), created a set of incentives for market participants that acted to ratchet prices upward once the pattern had been established. IOUs were required to sell their energy and to purchase all energy requirements through the Spot Market, i.e. they were not allowed to enter into any long-

term contracts for supply, which would have allowed them to hedge against the possibility of high prices in the future.

- The rules of AB 1890 required that all bids into the Power Exchange (PX) be balanced, i.e. that generators and loads pair up prior to the time that information was provided to the PX. These requirements triggered the following behavior:

- The IOUs incentive was to sell all or as much of their generating assets as quickly as possible, far more quickly than had been anticipated by the framers of AB 1890.

- Given that the IOUs now had little if any of their own generating capacity, they were required to purchase, unhedged, all of their electricity requirements through the spot market of the California Power Exchange.

- As prices began to rise, the IOUs (most specifically PG&E) realized that it was in their best interest to “game” the market so as to reduce the price in the day-ahead market where the majority of the energy was being purchased. This was done by dramatically under-scheduling their needs for the next day. This then caused the Power Exchange day-ahead market to clear at a relatively lower price.

- The remainder IOUs load went into the CA ISO real time market, which then would clear at a far higher (than the PX) price.<sup>4</sup>

- Generators quickly caught on to the strategy and ratcheted up their bids in the PX market while maintaining the balanced nature of transactions in the PX.

- Only at the end of 2000 did the CPUC and FERC allow the IOUs to enter into any long-term contracts and permit the PX to create a hedging instrument called the “Block Forward” contract – too little and too late.

The outcome became inevitable as the various elements in the Perfect Storm converged. Supplies were constricted, gas prices increased, demand increased, the IOUs developed the under-scheduling strategy and the generators responded. Energy that should have been hedged for delivery to end-users was explicitly not permitted to do so. Consumers felt the impact of a market structure in which all energy was clearing at volatile spot market prices. The political response at the State level was to maintain the consumer price cap even though the IOUs were losing increasingly greater amounts of money with every kWh sold. The response from the Federal Commission was to cap bids into the spot market initially in California only and then in all of the Western Interconnection.

<sup>3</sup> It is critical to note that the response of the political system to rising prices was not to allow other customers to see prices (SDG&E customers had dropped peak demand by a reported 5%) but rather to apply price caps to SDG&E to match those of the other two IOUs.

<sup>4</sup> The expectation of the market designers was that the majority of all of the energy would be traded day ahead in the Power Exchange and other Scheduling Coordinator markets and that only a limited amount – often quoted to be 5% -- would be cleared in the balancing operations of the CA ISO.

### 3. California 2000, 2001: The Resulting Pattern of Spot Market Prices

Much has been written about the resulting price movements in California. We will only provide Figure 1, a graph of prices in the CA ISO market on an hourly basis for the period January 2000 through May 2001. Several points should be noted. The first is that prices remained at or below \$50/MWh until the spring of 2000. While there were several short price excursions in April and May, it was not until June that the extremely high prices hit. The flat periods reflect the decreasing level of price caps in the official market. The first at \$750/MWh in June, the second at \$500/MWh in July, the third at \$250/MWh in August, the fourth at \$150/MWh in January, and finally the end point in June of 2001 when continuing mitigation, based on the Commission's formula discussed below, was introduced. It is critical to remember that while these figures represent the market clearing price, they do not represent the maximum price paid for energy by the CA ISO since they do not include the many "Out of Market (OOM)" purchases, i.e. those that were sold into the CA ISO market from either non-ISO members within the state or by suppliers and marketers from out of state. The market structure imperfection that created the price difference for OOM also created the "Ricochet" strategy involving the sale of energy from a California generator to a buyer outside of the state in the day ahead market that is then sold back to the CAISO in the real time market thus avoiding the California PX bid cap. This strategy was made famous by Enron but implemented by others throughout the period prior to the June 19, 2001 FERC order placing all supply in the WSCC on the same rules.

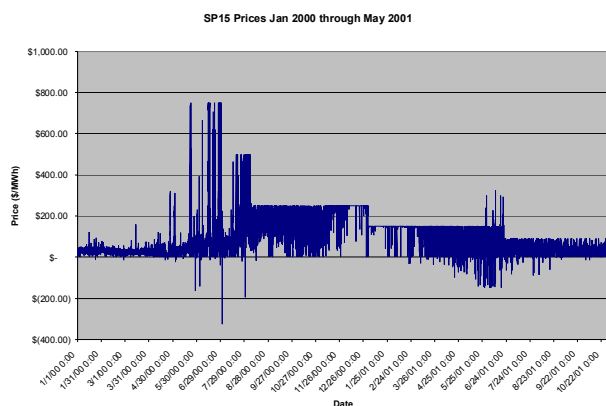


Figure 1: CA ISO clearing prices

### 4. Federal Intervention in the California Market

#### 4.1 Overview

Along with all the State agencies and the IOUs, the Federal Energy Regulatory Commission (FERC) has played a major role arguably both on the positive and the negative sides of the crisis. To the negative, they responded more slowly and with less effect than many observers would have expected. To the positive, they did initiate Federal action in November of 2000, and have established multiple hearing procedures to gather and summarize all the available data surrounding the events and to determine what refunds are due to California parties. These refunds are calculated from a formula that is based on simplistic assumptions of economic theory and engineering principles, with the goal of discovering where the market might have cleared had it not been dysfunctional.

The Commission has stated on multiple occasions that its actions were definitive in ending the crisis. Most, if not all analysts disagree that those actions in and of themselves had any affect but rather that the market fundamentals that so severely created the problem in the first place—restrictions on gas supply, high temperatures, rapid demand growth and low water—began to reverse themselves. That said, however, the Commission's actions are noteworthy both in terms of the continuous actions taken and in terms of the fact that they continue at the writing of this paper.

The paragraphs which follow present a highly compressed and summarized chronology of the actions of the Commission beginning in November of 2000 and continuing to the present. They are presented to provide a substantive backdrop to the procedures needed to reset a market *ex post*. Explicitly not included in the chronology is the demise of Enron Corp that has been suggested to be a causal factor in the price run-up in California.

#### 4.2 Chronology

**November 1, 2000** The Commission recognized the need for change in the rules of the California market and that the current stakeholder structure of the CAISO board was not able to make timely decisions. It ordered that the board be dissolved by January of 2001 and that an independent board be established. The members of that board were to have specific skills but no affiliation with market players. It stated that actions such as price caps or *ex post* price mitigation could be needed.

**December 15, 2000.** Eliminated requirement that investor-owned utilities sell all their generation into the PX; required 95% of demand be scheduled in advance

(and imposed a financial under scheduling penalty) and established a benchmark for long-term contracts; imposed an interim \$150 soft cap or breakpoint on spot markets pending the development of a longer term price mitigation procedure.

**March 9, 2001.** Order directing refunds or further justification for charges, offering a glimpse back to the days of cost of service regulation.

**April 26, 2001.** Order establishing a prospective mitigation and monitoring plan for California and requiring sellers with PGAs to offer all available capacity into the real time market (including governmental entities); the Load Serving Entities to develop load management programs; a single market clearing price auction in real time; price mitigation for available capacity in real time when there was a reserve deficiency during stage 1 alerts. In addition, the ISO and IOUs were to file a plan for an RTO by June 1, 2001

**May 16, 2001.** Order granting motions for emergency relief by Qualifying Facilities (QFs) as a result of not being paid for power provided to suppliers in the state.

**June 19, 2001.** Extended price mitigation to all of the WSCC when reserves in California fall below 7%. During non-reserve deficiency periods the price ceiling for bids was set to be 85% of the price during the reserve deficiency. The market-clearing price in the California spot market (the CAISO) was the market-clearing price for the WSCC. The rules requiring all generators to be available in the market (from April 26) were now applied to all generators in the WSCC with the exception of hydro.

**Early July 2001.** Extend, settlement conferences at the FERC chaired by Chief Administrative Law Judge (ALJ) Wagner in an attempt to arrive at a settlement between the State of California and the IOUs on the one side and the suppliers (generators) and marketers of power into California on the other. This settlement process ended in mid July with no agreement. ALJ Wagner handled the final two days as an open, evidentiary hearing in an effort to create a record for use in his recommendations to the Commission.

**July 25, 2001.** Order responding to (and accepting in large part) the recommendation of ALJ Wagner's methodology for calculation of Mitigated Market Clearing Prices (MMCP's) based on the heat rate of the last gas fired generator loaded in the California spot market times the actual spot price of gas. The order defined the scope and duration of the refund period to spot market transactions (not long-term or bilateral) and from October 2, 2000 to June 20, 2001 (the day after the final price cap

order covering all of the WSCC). ALJ Birchman is appointed to hear the California Refund Case. The Order also ordered a second set of evidentiary hearings under a second ALJ (Citron) to review claims that the markets in the Pacific Northwest (PNW) had been severely impacted by the dysfunctional market in California and should also be subject to price mitigation.

The structure of the CA Refund case is defined around three issues. Subsequently it was agreed by the parties that it would be divided into two phases. The first phase was to present evidence on Issue 1, the calculation of the Mitigated Market Clearing Price. The second phase, Issues 2 and 3 was to present evidence on how much the suppliers and marketers will "refund" to California (Issue 2) and how much is owed (issue 3) by the various California parties to the suppliers and marketers. This second phase is referred to as "Who owes what to whom."

**September 26, 2001.** Reporting of recommendations and findings of fact of ALJ Citron in the PNW case. The findings were that the market in the PNW was not (in the main) a real time spot market but rather a mature bilateral market that functioned as such during the refund period. Those who participated in the market did so at their own choice and with knowledge of the risks. The recommendation was that there be no price mitigation in the PNW.

**November 6, 2001.** Written responsive testimony was filed on Issue 1, calculation of the Mitigated Market Clearing Price. The CA ISO had already provided calculations based on their interpretation of the FERC July 25<sup>th</sup> order. Generators and the marketers now provided their calculations. See below for the positions taken.

**December 6, 2001.** The Commission suspended the procedures of the CA Refund case until after the issuance of their major finding in California due before the end of the year.

**December 19, 2001.** The Commission released a series of orders on rehearing and provided a more clear direction for prospective (and to a lesser extent retrospective) handling of Western Market conditions. In summary they stated (97 FERC ¶ 62,172 at 61,275) "we now exclude governmental entities and cooperatives from price mitigation with respect to bilateral transactions outside of the ISO spot market and with respect to must-offer requirement outside of California. We also eliminate an 'underscheduling' penalty imposed earlier. We state that marketers, load serving entities and hydroelectric generators may submit evidence that the refund method results in a total revenue shortfall in the organized California spot markets for their transactions during the refund period, after the conclusion of the refund hearing."

This latter option had been provided earlier to generators. In addition, and critically (negative) to the generators and marketers, the Commission stated that the MMCP was to be a price cap. The actual price to be used in the refund procedure was to be the lesser of the actual market clearing price, the price cap or the calculated MMCP. The Commission then restarted the CA Refund procedure.

**March 11 to 15, 2002.** Hearings held at the FERC before ALJ Birchman, on Issue 1, the calculation of the Mitigated Market Clearing Prices for the Refund Period, the time between October 2, 2000 and June 20, 2001.

**April 16, 2002.** The Commission set for hearing a set of complaints regarding whether long-term bilateral (i.e. not spot central market) contracts written during the time of dysfunctionality of the California markets should be cancelled. The complainants are the Nevada Companies, Southern California Water Company and the PUD No. 1 of Snohomish Count, Washington. This reflects a collateral complaint involving the abrogation of contracts negotiated between willing buyers and sellers outside of centralized markets. The Commission stating that those attempting to overturn the contracts “bear a heavy burden.”

**July 17, 2002.** The Commission responded to the proposal CAISO’s Market Design 2002 (MD02), affectively throwing out all of the market power mitigation proposals as written and incorporating an Automated Mitigation Procedure with Commission defined parameters and resetting the WSCC bid cap at \$250/MWH.

**July 31, 2002.** The Commission issues a Notice of Proposed Rulemaking (NOPR) to establish a Standard Market Design for electric markets under its regulatory control. A 600+ page document focuses on correcting the market imperfections of California that led (at least in part) to the price instability and spikes in California. The NOPR focuses on standardizing a wholesale market that clears at Locational Marginal Price, contains a day ahead and a real time clearing market, collapses many of the ancillary service markets into a single energy market, and provides those serving load to hold forward contracts for capacity and/or deliverable energy equivalent to their peak need out three years plus a minimum of a 12% reserve. The NOPR sets the tone, if accepted, for wholesale market structures throughout the country. California through the head of the CPUC contests FERC’s legal ability to implement the structure.

**August 2002.** FERC Staff release a report suggesting that the natural gas prices for the west and used in the CA Refund case that are based on published indices are biased because the prices could have been manipulated by

traders, particularly those at Enron and using the Enron On Line system. They suggest that the CA Refund case should not use the reported gas prices but instead should use Henry Hub plus a pipeline delivery price to calculate the MMCP. The staff states that they have not taken any measure of the scarcity of gas, gas storage, or pipeline capacity into consideration in their recommendation.

**August 13, 2002.** The Commission formally requests the opinion of participants in the CA Refund case as to whether the recommendations of the Staff Report should be accepted as the natural gas price for use in the MMCP calculations.

**August 19 to 24, 2002.** Hearings held in San Francisco on Issues 2 and 3 before ALJ Birchman. Following on the responsive, rebuttal and surrebuttal testimony, a major issue in the case is whether the Power Exchange has handled congestion payments within their purview correctly, i.e. in accordance with the Commission’s statement that the refund procedures were not to mitigate congestion.

**October 15, 2002.** Comments are due to the Commission on the correct gas price with no firm expectation as to when a decision may be made.

**November 15, 2002.** Comments are due to the Commission on the Standard Market Design NOPR. The Commission had stated its intention to issue the final order at the close of the year. Given the intense objections received to date from the Pacific Northwest governors, the governor of California and a consortium of utility executives and politicians in the Southeast, it is unlikely that this schedule will be met.

## **5. The Refund Solution: Mitigated Market Clearing Prices, MMCPs**

### **5.1 The Original Proposal and the Position of the California Parties**

Issue 1, the MMCP the greatest controversy given what the Commission and the ALJ believed to be relatively straightforward instructions in the July 25<sup>th</sup> order. The market prices were to be mitigated using a simple formula based on the heat rate (HR) of the least efficient natural gas fired unit run in the real time market in California, the natural gas price and estimated O&M costs (set to \$6 by the Commission). It also include a multiplier (after January 5, 2001) of 10% to reflect the credit risk associated with sales into the financially shaky California market – remembering that suppliers were, in general not paid for deliveries made after January 2001.

$$\text{MMCP} = [(\text{HR} * \text{GasPrc}) + (\text{O} \& \text{M})] * 1.1$$

Though seemingly simple, all values in this equation have become subject to interpretation and litigation as has the basic data required to carry out this calculation for each of the **37,728** 10 minute time blocks I the refund period of October 2, 2000 to June 20, 2001.

The position of the California ISO and a group of other parties from California (made up of the three IOUs, the CPUC, the Attorney General and the Electricity Oversight Board) was that the appropriate heat rate to use was the incremental heat rate, because that was the number used in the ISO's software as well as the number used in their own initial presentations to the Commission. For the gas price, they argued that it should be the average spot price for gas (*i.e.*, not necessarily the price seen by the marginal generator). An issue not anticipated by the Commission's simple equation was that of defining the generator stack for those units eligible to set the market-clearing price. Should it be all units that were dispatched for a given hour? Only those units serving California's spot markets? Or, as put forward by the California parties, should the generator stack be restricted to only those units that actually bid into and were dispatched by the ISO's BEEP (Balancing Energy Ex Post) software and thus officially part of the CAISO BEEP market.

Looking closely at this position, it can be observed that a smaller generator stack (of only the most efficient units), relatively low incremental heat rates and low gas prices all combine to suggest that the market prices *should have been* very low indeed, during the refund period.

## 5.2 The Position of the Suppliers

The position of the suppliers and the marketers was that the stated goal of the Commission was to create a price that would reflect what a market would have actually (not theoretically) produced, given the actual, historical data that was available to all participants. Their position with regard to nearly all of the individual elements of the debate surrounding the proper implementation of the Commission's formula was that a generator would not willingly have been in the dispatch, if

1. It had known, in advance, that it would lose money, and
2. It had the opportunity and the ability not to be dispatched.

Applying this position to the selection of the appropriate heat rate results in identifying the average, or operational heat rate, and not the incremental rate.

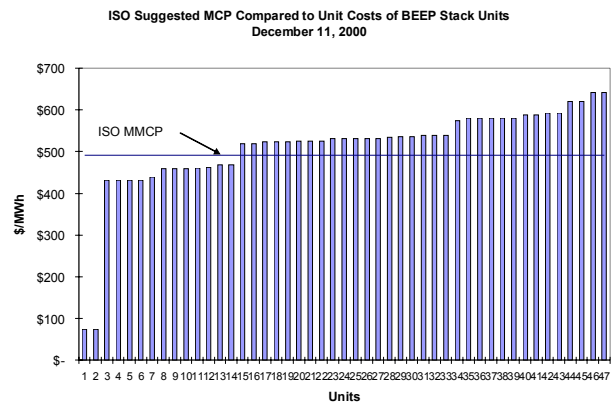
Specifically this can be seen in examining the data for the 108 gas fired generating units that were found to be eligible to set the MMCP. For 75 of these 108 units, the incremental heat rate curves are always less than and never intersect the operational (average) heat rate curves.

As a result, when any of these 75 units were the marginal unit, their revenue would be less than their costs if the incremental heat rates were used to set the *ex post* price. In the real world these units would not run in such a situation.

As a second example, units such as Moss Landing (740 MW) do not reach the point at which the incremental curve crosses the average curve until the unit is generating more than 670 MW (91% of its capacity). For all 25 of these 33 units that are greater than 50MW in capacity, the average percentage loading before the incremental and operational (average) curves cross is 83%. The argument is that these units would have decided *not* to run under the *ex post* conditions that the California Parties' would hope to impose on the market.

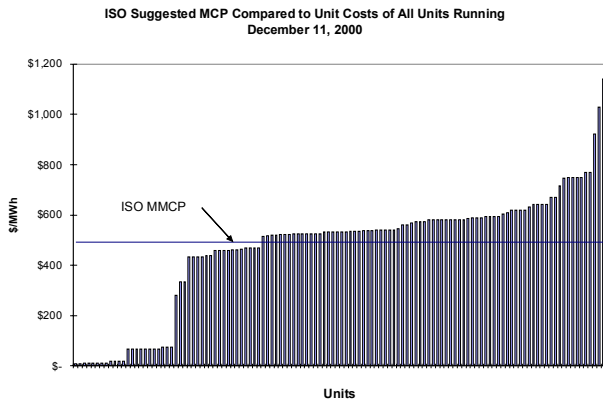
Full analysis of all units for the entire refund period indicates that individual units would have lost money in up to 87% of the 10-minute intervals during which they were operating if the *ex post* market price (the MMCPs) were based on incremental as opposed to operational heat rates. Simply put, the result of implementing the Commission's formula according to the CAISO's logic is that nearly every unit in the generator stack would lose money during some ten-minute intervals. This result is clearly not market-based since in reality these units would not have run had they known that they would be running at a loss.

As can be seen in Figure 2, roughly two thirds of the units in the BEEP stack are recovering less than their operating costs during this time period.



**Figure 2: Losses in BEEP stack units**

Figure 3 shows the level of operating losses for all units subject to price mitigation.



**Figure 3: Losses of all units subject to price mitigation**

### 5.3 The FERC Staff report on Natural Gas

The procedure for calculation of the “simple” formula for MMCP became more complicated with the release of and Commission response to a FERC staff report on the possibility of manipulation of the reported prices for natural gas in California. On August 13, 2002 the Commission issued a “Notice Requesting Comment on Method for Determining Natural Gas Prices for Purposes of Calculating Refunds” concurrently with the release of the Commission Staff Report questioning the validity of the prices reported in the publications like *Gas Daily*. At the time of writing comments have yet to be submitted and no decision made. The proposal of the staff is that the price of gas should be set at that of the principle pricing hub, Henry Hub plus the cost of pipeline capacity to the market. The Staff admits that this methodology – and their analysis – did not take into consideration any element of market dynamic, namely shortage in the market in general and shortage in storage in California and the West in particular.

That said, the issue remains that if this proposal is accepted, the gas price used will be roughly 45% lower than the average of what has been used to date in the proceeding. The affect that this will have on both the procedure and the market is dramatic. On the proceeding it is most likely that nearly (if not all) of the generators and the majority of the marketers will find it necessary to go to the Commission to exercise the escape clause of a cost of service finding because the arithmetic of the MMCP procedure will drop their calculated revenue below their actual costs. From the perspective of the overall market it will turn investment from a chill to a deep freeze as investors perceive the Commission reviewing and rewriting all central market payments and potentially those in bilateral contracts as well.

### 5.4 Summary: Ex Post Market Price Mitigation

The conclusion that is reached based on the past two years of experience in attempting to reset the prices in the California market from October 2, 2000 to June 20, 2001 is that the process is nearly impossible. The rule established initially by the Commission in July of 2000 was relatively simple and seemed to be implementable. It had the strength of being limited to only the centralized market, if being constrained to only natural gas fired units (though that too was subject to initial dispute) and had the benefit of what was assumed to be accurate *ex post* data as to what had actually transpired during the period.

The Commission had added one additional helpful element to the process and that was to minimize what in the Pacific Northwest (PNW) case had become known as the “ripple” effect – the need for any participant in a bilateral contract that was the one being mitigated to find the entity from whom they had purchased and attempt to move the loss back through the daisy chain of bilateral contracts. The judge in the PNW case recommended against any mitigation. The Commission in the California Refund case has stated that if generators or marketers believed that their entire portfolio lost money through trades during the refund period, given the rules for the refunds, they could come into the Commission for what essentially would be a cost of service study.

Unfortunately, nearly all of the assumptions made in the California Refund case in terms of cleanliness of methodology were incorrect from the starting point. There was simply too much money, political prestige and, in several cases, the existence of individual companies at stake. A 1% shift in the likely outcome could amount to as much as a 15 million dollar swing in the results if the data approved by the Commission were to be used, and as much as a 90 million dollar swing if the numbers quoted by the political process within the State were used.

Second-guessing as to how the market *might* have behaved under hypothetical, pure competition does not seem possible. The difficulty in determining *ex post* prices, initially thought to be a straight forward application of the Commission’s simple formula, has demonstrated the futility of *ex post* price mitigation as a tool for guiding or improving market behavior and outcomes.

## 6. Automatic Mitigation Procedures in California: The *Ex Ante* Alternative

### 6.1. Background

The Commission in the Standard Market Design NOPR has fastened on to an alternative for the handling of market behavior, in theory; to prevent another meltdown as was seen in California in 2000/2001. That has been to suggest that it is possible to design a dynamic structure that will apply price (or bid) caps to markets or to

elements of markets in which prices exceed a prespecified band.

These *ex ante* mitigation concepts that have subsequently been incorporated into the proposed Standard Market Design were developed in the more functional Northeastern markets. To see how these broad concepts may, again, be implemented to guarantee a dysfunctional (this time long-term) market, California provides an excellent point of departure.

## 6.2 The California MD02 Proposals

In the late winter and spring of 2001 the California ISO initiated a process to develop a transitional market structure, the Comprehensive Market Design 2002 (MD02) released on April 19, 2002. The design was intended to provide the blueprint for moving from the existing west-wide structure with FERC controls (that were to expire on October 1, 2002) to a more market-based alternative. The plan was filed at the Commission and, in large part rejected by the commission in their order of July 17, 2002. The importance of MD02 for this paper is the fact that it attempted to incorporate a range of **highly** conservative measures for *ex ante* price mitigation measures. Three specific price mitigation measures – a so called Damage Control Bid Cap, Automated Mitigation Procedures, and a 12 Month Market Control Index (12MMCI) were proposed. Together these mitigation measures have been described by Dr. Frank Wolak, Head of the CAISO Market Surveillance Committee, as the ultimate case of belts and suspenders.

Each of the measures proposed by the CAISO finds its origin in some element of market mitigation seen in another well-defined, functioning and well-developed market in North America. The CAISO, however, proposed to modify each of these measures in an effort to apply it to the currently evolving California electric market.

**Local Market Power Mitigation.** The principle of the measure is derived from that in PJM where it is applied to major interfaces with significant internal generation. The PJM rules do not call for mitigation based on a single constrained interface as was proposed in California, but rather on a set of conditions that must apply to indicate that market participants behind the constraint can exercise market power. The CAISO included none of the PJM liberalizing or tempering conditions in their proposal. In California, as the rules were written, it would be possible for little more than a single unit being called out of merit in a broad zone to trigger price mitigation of a major region or possibly the State as a whole.

**New York-style Automated Mitigation Procedures (“AMP”) Applied to California.** Automatic Mitigation

Procedures are based on the statistical definition of a threshold bid price range and are designed (1) to differentiate between scarcity and market power in the bids that exceed the stated threshold; (2) to limit interventions into the market; and (3) to avoid retroactive refunds. As is described below, AMP has been proposed the FERC NOPR as a probable tool for market price mitigation in the Standard Market Design. The AMP concepts proposed by the CAISO were borrowed from the New York market structure where they were customized to the New York market structure. The MD02 plan was to simply take the structure and apply it with different, tighter thresholds.

New York applies AMP to a day-ahead market. The CAISO on day one of MD02 has no day-ahead market yet proposed the application of AMP for both the day-ahead Residual Unit Commitment (RUC) process and the real-time market. The AMP of New York developed a detailed methodology by which they generate the set of unit-specific reference prices that serve as the competitive benchmark against which thresholds are applied and bids are evaluated. The result is that the New York structure operates on sellers’ bids accounting for fuel and transportation prices as well as environmental and opportunity costs in close to real time and on marginal costs only as a last resort.

The thresholds in New York have been set relatively wide. The New York bid impact screen provides a threshold of the lesser of 300% of the reference price or \$100. CAISO, on the other hand has proposed 100% of the reference price or \$50, which ever is less. The rejected proposal of the CAISO presented a little more than a tight market price cap. The Commission in its July 17 Order recognized this when it, not the CAISO, reset the threshold rules,

**12-Month Market Competitive Index (12MMCI).** As yet another tool for *ex ante* price mitigation, the CAISO proposed to establish a 12-month rolling competitive baseline average cost index, on the basis of which it would evaluate the market’s competitiveness. Any deviation from this baseline greater than \$5/MWh would re-trigger FERC’s west wide price mitigation that was to be in effect until October 1 (but was redefined on July 17). Under the proposal the price mitigation would remain in effect for six months or until “the market is found to be restored to competitive conditions.” The stated objective was to provide an automatic mechanism to assure that prices in California are maintained at a competitive level.

Had it been accepted, the effect would have been to remove from the Commission the authority to determine what are just and reasonable rates in wholesale electric markets by proposing to predetermine, based on a highly simplified mathematical model of what was “competitive.”

**Damage Control Bid Cap.** The final price mitigation procedure proposed by the CAISO was again based on the Northeastern markets. The Damage Control Bid Cap departed both in principle and value from the FERC approved Northeastern model. In principle, the bid cap is meant to serve as a demand bid proxy in the absence of demand-side bidding, and in the Northeast is set at \$1,000/MWh, a level that is unlikely to be less than the willingness of any demand bid. The CAISO has chosen to utilize the bid cap as a supply-side bid mitigation strategy, and set the bid cap to remain at the then current level (not less than \$108/MWh, and adjusted up if necessary based on gas price indices). At these price levels all (including the Commission) recognized that the cap was harmful to long-term investment and in their July 17 Order the Commission set the initial level of the cap for the WSCC at \$250/MWh.

**Summary: The California proposals.** At the FERC hosted stakeholder meetings in San Francisco on April 4 and 5, 2002, Professor Frank Wolak, Chairman of the Market Surveillance Committee of the California Independent System Operator, referred to the proposed multiple market mitigation proposals in MD02 as a case of “belts and suspenders.” When asked whether he and members of the Market Surveillance Committee had been part of the process of development of MD02 he answered that he had not.

The proposals by the CAISO had only a single objective taken either individually or as a whole; to hold low and, if possible, to reduce the cost of electricity to end-users in California. While one might argue that this is a reasonable political goal, or possibly an element of the objectives of the Public Utility Commission who are also concerned with adequacy and reliability, it is equally obvious that this is not an objective of an *Independent* System Operator. As a FERC regulated entity, the CAISO’s mandate is to favor no individual player in the market (including the consumer) but to operate the market so as to minimize total cost (subject to physical constraints of delivery) given the market bids of the individual buyers and sellers.

On November 1, 2000 the Commission ordered the dissolution of the CAISO stakeholder board as being deadlocked and incapable of decisions. It ordered the creation of an *independent* board of 5 specifically skilled members. On January 29, 2001 the California Legislature passed ABX1 5 requiring the governor to appoint a 5-member board of California citizens, which was then done. In their July 17<sup>th</sup> Order the Commission reiterated their order that the current non-independent board resign and that an independent board be established using a set of procedures included in the July 17 Order. The board, at the encouragement of the governor, declined. On August 18, 2001 the Commission filed a formal complaint

in the 3<sup>rd</sup> Federal District Court requesting a court order that the FERC July 17<sup>th</sup> Order be enforced. It is safe to say that at the time of this writing there exists a stand-off that is working to the detriment of the California markets as well as power markets throughout the US as regulatory uncertainty has continued to be a dominant decision factor for both traders and investors.

## 7. Mitigation and Markets: The Long Run impacts

The design and implementation of the *ex post* price mitigation for the California spot markets was focused on the immediate needs of the state at the time, combined with minimal thought for perhaps one year into the future. Unfortunately possible repercussions for the long-term strength of the electricity markets, and the electric power system itself, were not addressed in any of the Commission’s multitude of orders. As pointed out in the discussion over the appropriate heat rate data to be used in the Commission’s MMCP formula, some results could lead to generating units running at a loss. These results suggest that units would decide to not run in the short-term. If these policies of mitigated prices and price caps were to continue over a longer period of time, and so essentially short circuit the market dynamics that provide incentives for longer-term investment, they could result in dangerous consequences of investors deciding not to invest in the long-term. Faced with the unrealistic expectation from FERC that generators would either operate at a loss or accept a return to cost-of-service regulation, investors will choose to go elsewhere. And the ‘elsewhere’ in this case is not simply to a different type of generating technology or to a different state, but more likely to a different industry altogether. Such dynamics would have a stagnating effect not only on capital investment, but also on R&D for the power industry.

## 8. Ex post vs. Ex ante: The Market Incentive

The California electricity markets are currently subjected to both *ex post* and *ex ante* price mitigation. While the state agencies and utilities, along with the electricity customers may view these policies as the only means available to keep prices “just and reasonable,” this price mitigation only serves to undermine all hope of market development and to signal a return to cost of service regulation. The reason for these projections is that price mitigation distorts the most basic feature of competitive markets – the price signal. While it is true that price mitigation may be an effective tool in correcting short-lived market distortions, the idea that price mitigation can

be a permanent component of a market is antithetical to the idea of a market.

The distortionary effects of *ex post* price mitigation are understood in terms of the perverse signal it sends to market participants for future decisions, on both the demand and supply sides of the market. Those on the demand side have no need to change their current behavior (*i.e.*, the California state agencies do not need to develop policies that will pass on the true cost of energy to customers) because any restraint that might otherwise be learned in terms of consumption patterns simply can be avoided by imposing price caps, *ex post*. This is not to say that prices *were* just and reasonable during the refund period in the California Refund Case, but if customers had seen the prices early in the crisis, it is possible that a response of decreasing demand could have prevented the escalation of the crisis.

On the supply side, *ex post* price mitigation punishes all suppliers whenever a market dysfunction, caused by exogenous factors, market participants, or both, is identified. These all-inclusive mitigation measures distort the operation of the market by providing a disincentive for suppliers to take any financial risk. For immediate dispatch decisions generators will be unlikely to run high cost generators when the real-time price is high, because they learn that the price may be lowered *ex post*. Longer term investment decisions are similarly distorted (as discussed above as well), and the blithe offer for companies to go the FERC for a cost-of-service review of an entire portfolio does little to improve the investment environment. No company would willingly run any unit at a loss, even if others bring in net revenue.

What of the role of policy makers in the development of the California electricity markets? *Ex post* price mitigation also removes the need for state and federal officials to endeavor to thoroughly understand the context for and the dynamics of the markets they attempt to design and execute. If they get the rules wrong the first time through the process, they can react to public sentiment, successfully address the visible symptoms of market turmoil, and pay shockingly little attention to the underlying causes.

*Ex ante* price mitigation, as currently implemented in California, serves only to prolong the distortionary effects of the *ex post* mitigation, to the point that no party, supply-side, demand-side or government officials, will ever need to learn how to execute or operate in a market. These same parties may view living under the security of indefinite price mitigation as having bright points for the very same reason – no party will ever be required to learn how to execute or operate in a market.

One place that this approach brings us though is to permanent mitigation policies that are only thinly veiled versions of cost-of-service regulation. This apparent movement in turn raises the question of why the industry

ever began the move toward deregulation and industry restructuring. The reason is that the regulated industry structure was no longer effective in maintaining efficiency in system operations or in attracting investment for developing and installing new technologies. The cry for a return to the good old days, presented partly through a call for ongoing *ex ante* price mitigation, arises from looking through rose colored glasses and the desire to work with the familiar rather than contend with the unknown and the uncertainty surrounding the effort to create new and well-functioning electricity market.

## 9. Conclusions

If there is a conclusion that one may reach through this analysis it is that markets, and those who trade in them, behave so as to test the limits of all rules. If the rules have edges, participants will find them—our economic system is *designed* to give strong incentives to market participants to push the edges. If the rules have explicit or implicit loopholes they will be found and will be exercised. Participants follow their fiduciary duties to maximize their profits – and those of their shareholders – within the rules of the markets. When the rules are imperfect as certainly was the case in California, it is the market participants who are first and finally charged with unconscionable acts of greed while the market designers – politicians and their appointees – walk quietly into the sunset.

Designing market rules that function is a challenge, not only to get a good starting point, but also to recognize when mid-course corrections are required. As we point out, the goals of the SMD Automatic Mitigation Procedures is to provide the ultimate tool for mid-course corrections – a continuous process that will follow the flow of the market, yet keep prices within acceptable bands. While a creative solution in many ways, it is also one that denies participants in the market the financial benefits of the upside price swings while leaving them to hold all the downside risk. The SMD process, in the attempt to design a “standard market,” appears to eliminate many of the basic incentives that would encourage participation in a market in the first place.

## 10. References

- [1] All reference to the Federal Energy Regulatory Commission may be found on the FERC web site at: <http://ferc.gov/electric/bulkpower.htm>
- [2] All references to the California Independent System Operator may be found on the CAISO web site at: <http://www.caiso.com/docs/2001/12/21/2001122108490719681.html>