CALIFORNIA'S ELECTRICITY CRISIS: HOW BEST TO RESPOND TO THE "PERFECT STORM"

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The fact that California is currently tackling an electricity crisis is no great mystery.[1] Today's newspapers, television news programs, and trade journals are inundated almost daily with stories describing the state of California's electricity affairs. However, politics and finger-pointing have obscured most of the facts which are crucial to informing us as to how best remedy the situation. Identifying which regulators or market participants are to blame does little to right what has gone wrong.

Both the Federal Energy Regulatory Commission (FERC) and the Public Utilities Commission of the State of California (CPUC) have issued orders stating that California's restructured electricity market has significant flaws.[2] Hindsight demonstrates that California's restructuring plan was premised on illogical policies and poorly designed market structures. Moreover, regulators have failed to appropriately respond to the clearly identifiable and demonstrable market flaws. Yet, the magnitude of the current electricity crisis in California is the result of a meteorological "perfect storm" effect. Poorly structured markets, ineffectual regulatory responses to correct market flaws, limited generation supply, higher-than-anticipated increases in demand, an economic slow-down, dryer-than-normal weather,[3] and sharp increases in natural gas prices—none of which alone would be likely to wreak debilitating havoc—have collided at just the right time to produce the current crisis. The result has been a crisis that has caused the California Power Exchange (Cal PX)—one of the two entities created by California's restructuring plan—to close its doors and file for bankruptcy. The crisis also has pushed California's two largest utilities to the brink of bankruptcy and caused the California Independent System Operator Corp. (Cal ISO) to resort to rolling blackouts; all of which threaten the world's sixth largest economy.

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1. Although California is also contending with problems in its natural gas markets, the focus of this article is the electricity market.

2. These various decisions are currently the subject of ongoing litigation in both the federal and state arenas.

3. For example, dry weather has resulted in lower-than-expected hydroelectric reserves.

The situation can be rectified. Importantly, the current weather pattern, gas prices, and economics will not remain stagnant. As for issues arising directly from the electricity markets, throughout the restructured market's brief history, market participants have invested significant energy in identifying market flaws and potential enhancements to the California market.[4] However, market participants have put forth divergent views on how the market should function. Moreover, in response, regulators and market operators had been loath to make wholesale changes to the system, preferring instead to tinker with discrete operational and procedural issues. It is only the current crisis that has pushed regulators and California officials to try to identify and correct the major flaws in the market. Yet, to date, regulators have failed to take the actions necessary to sufficiently address these major market flaws and ensure that competitive markets will succeed.

Part I of this article describes the chief flaws that regulators, market participants, and industry experts have identified with respect to the California market. Part II addresses the remedies that regulators and state officials have proposed to correct these market flaws and respond to the crisis at the federal and state levels. Finally, Part III describes how the current responses fail to properly fix the market's flaws, and proposes a coordinated holistic approach to fixing the market.

PART I.

Some of the current problems inherent in the California market today are the result of flaws in the market's foundation. Specifically, the CPUC's initial proposals and decisions that established the framework for restructuring California's electricity market rested upon unsound logic and included serious market design flaws. These policies and decisions formed the basis upon which California's restructuring law—Assembly Bill 1890 (A.B. 1890)—was structured. As a result, California promulgated a restructuring plan premised on a fundamentally weak foundation.

As identified in the CPUC rulemaking, known as the "Blue Book,"[5] and codified in A.B. 1890, the goals of restructuring were: (1) consumers should have direct access to generation suppliers, marketers, and brokers; (2) California's consumers should have a reasonable and fair opportunity to benefit from a competitive electric services industry; (3) promote efficient and environmentally sound electric services; (4) promote the state's economy through growth, productivity, and competitiveness of the electric industry; and (5) ensure universal access to a basic and affordable package of electric services.[6] In order to meet these goals, the CPUC

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4. This fact is abundantly evident where the California Independent System Operator Corporation (Cal ISO) had amended its Tariff 35 times as of December 31, 2000.

5. California Public Utilities Commission, Rule Making on Proposed Polices Governing Restructuring California's Electricity Services Industry, R.94-04-031 (Apr. 20, 1994).

6. A.B. 1890 § 854, 1996 Cal. Stats. 854, codified, in relevant part, at CAL. PUB. UTIL. CODE §§ 330-398.5 (Deering 2001).

relied upon competitively priced generation and, open and non-discriminatory transmission access to that generation by both wholesale and retail customers. However, the essential building blocks for a competitive supply of generation simply did not exist. California's deregulation model did nothing to address this issue. Additionally, the initial proposals and decisions that established the framework for restructuring California's electricity market included serious market design flaws that would frustrate, rather than support the development of a competitive market for generation.

A. *Poor Competitive Conditions—Insufficient Generation Supply*

The premise of California's restructuring plan was to provide consumers equal and open access to competitively priced generation. In theory, this concept is logical. The flaw when this theory was put to practice was that California's generation supply was insufficient to meet California's demand. Moreover, there have been significant barriers to the entry of new generation within the State. As a result, the market has been unable to respond to the price signals that dictate that new, more efficient, lower priced generation is needed to compete and displace existing supply.

It is clear that there is insufficient generation in-state to serve California's demand. Moreover, little new generation capacity has been added to the in-state supply. In fact, between 1996 and 1999, only 672 MW of net generation of additional capacity was added in California—roughly two percent of California's approximately 55,000 MW of generation capacity.[7] During that same time, demand in California has grown by over eight percent.[8]

Aside from the lack of sufficient generation, much of California's in-state generation facilities are old and inefficient. According to the California Energy Commission, fifty-five percent of the State's generating facilities are more than thirty years old. Older generating plants overwhelmingly are inefficient when compared to newer vintage combustion turbines. Older plants have extremely high heat rates and require more fuel to keep the plants running. In addition, older plants have significantly higher NOx and SO_2 emissions rates. Finally, as with any older asset, older plants require significant investment and time in operations and maintenance. As a result, older plants generally require more off-line time for repairs to comply with existing emissions standards and to maintain maximum operational capability.

To meet its needs, California is forced to rely heavily on imported power during periods of peak demand. Yet, California is not the only state that has seen significant growth in demand. The neighboring states of

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7. Electricity Oversight Board & California Public Utility Commission, California's Electricity Options and Challenges Report to Governor Gray Davis at 36, (Aug. 2, 2000), *available at* http://www.cpuc.ca.gov/word_pdf/REPORT/report.pdf. [Hereinafter CPUC Report].

8. California Energy Commission, Staff's Outlook for California's Electricity Consumption by Sector (1999-2000), *available at* http:www.energy.ca.gov/electricity/consumption_by_sector.html.

Arizona, Oregon, and Nevada have also experienced significant load growth, limiting the ability of out-of-state generators to export power to serve California. Moreover, California's transmission system is severely constrained, limiting the ability of generation suppliers to import, export, and move power to serve California.

There are a number of reasons for the lack of generation in California. During the 1990s, California's regulatory environment went through significant changes. The CPUC began to move away from strict cost-of-service regulation to incentivized regulation. This process took a number of years during which regulators worked to perfect the new regulatory regime. On a general level, this changing regulatory environment likely scared away risk-bearing investors who seek stable, known regulatory rules before investing in regulated markets.[9]

More specifically, the CPUC's new incentivized regulation deterred investment in capital projects such as generation plants. During the early 1990s, performance-based ratemaking (PBR) took hold in the CPUC. Under PBR, utilities' rates were keyed to an ability to provide efficient service at lower costs. The lower the utilities' costs, the bigger the profits for the utilities' shareholders. Therefore, utility managers had no incentive to make long-term investments in capital-intensive projects such as new transmission or generation assets.[10] In other words, there was a disincentive to build new generation or invest in transmission upgrades.

California has also taken a strict position with respect to environmental protection and the participation of the public in issues affecting the environment. The State's generation siting and permitting procedures have been extremely complex. The California Energy Commission, charged with siting and permitting new generation, scrutinizes the impact of new generation on land, water, and air. The participation of the public in the permitting process has ensured that socio-economic impacts have been taken into account as well. Not surprisingly, the permitting and siting process traditionally has taken so long that it has frustrated the development of generation projects. As a result, this lengthy and complex process created significant risks that new generation would not be built, deterring such potential investment.[11]

In short, California relied upon an insufficient, aging supply of generation and constrained transmission system as the basis for its competitive market. However, for competitive forces to work properly, there must be relatively easy access for new sources of supply to enter the market. The unstable regulatory picture and environmental policies in California have served to discourage investment in California's electricity industry infrastructure. In turn, the lack of such investment has created significant barriers to the ability of new generation supplies to enter the market in California.

9. *Id.* at 38.

10. CPUC Report, *supra* note 7, at 36.

11. *Id.* at 38.

B. Flawed Policies and Market Rules

The discrepancy between the surging growth in demand and the current state of supply is a primary reason for the current state of California's power market. However, it is clear that the restructured market's design, structures, and operating rules have exacerbated the problems resulting from the supply and demand situation. The investor-owned utilities (IOUs), the Cal ISO Market Surveillance Committee (MSC), the FERC staff, and regulators in California have all compiled various lists of the flaws in the California market. Rather than attempt to identify them all, this article describes the primary flaws cited by investigators. Viewed *seriatim*, it is clear where California's market rules failed.

(1) Buy-sell Requirement/Lack of Forward Contracting

A primary aspect of restructuring, as proposed in the CPUC's Preferred Policy Decision, and embodied in California's restructuring law —A.B. 1890—was the requirement that the IOUs bid all of their generation into the Cal PX and buy all of the power necessary to serve their full-service customers out of the Cal PX.[12] This buy-sell requirement was to remain effective until the IOUs had recovered their stranded costs through the Competition Transition Charge (CTC). The stated rationale for the buy-sell requirement was benign. Specifically, the CPUC believed that that the buy-sell requirement would:

> (1) reduce the scope and burden of regulatory issues associated with determination of the dimension of the assets which are non-competitive in a transparent market;
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> (2) ensure that those customers who elect to rely upon their distribution utility to procure their electric energy will receive the benefits of those competitive market prices; and
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> (3) provide a sufficient depth to the Exchange that its market signals may be relied upon as a benchmark for choices to opt for contracts for differences or direct access arrangements.[13]

In reality, the effect of the buy-sell requirement on the market clearly was insidious. The buy-sell requirement forced the IOUs to rely on spot market power to serve their full requirements customers. The IOUs were unable to hedge against volatile spot market prices by entering into fixed forward financial and physical contracts. Moreover, because of the level of the retail rate freeze and CTC collection, retail customers were insulated from high spot market prices, eviscerating demand responsiveness.

The California experience manifestly demonstrates the importance of resource diversity and forward contracts. It is undeniable that forward contracts can benefit consumers by providing load-serving entities (LSE)

12. Preferred Policies Governing Restructuring California's Electric Service Industry and Reforming Regulation, 64 CPUC 2d 1, 166 PUR4th 1, 1995 WL 792086, at *24 (Dec. 20, 1995).

13. *Id.*

with the ability to lock in a fixed amount of energy for a fixed price for a fixed period of time. By engaging in such contracts, the LSE need only rely on the spot market for the shortfall between the contracted-for amount of forward energy and the actual amount of energy needed to serve load.[14] The Cal ISO independent MSC recognized this fact in its report on the California bulk power market: "[w]ith complete freedom to purchase forward both energy and ancillary services from generation unit owners in or outside the ISO control area, the utility distribution companies (UDC) could have eliminated or significantly reduced (depending [on the] quantity of forward energy or capacity purchased) their exposure to spot market price volatility."[15] Thus, forward contracts limit the end-use customers' exposure to price volatility.

According to the FERC Staff, forward contracts also help to mitigate the potential for generation market power in energy spot markets. Financial forward contracts, such as contracts for differences (CFDs), serve just this purpose. The basic CFD requires the generator to pay the buyer for the difference between the spot price and the contract's stated strike price when the strike price is lower. On the other side of the deal, the CFD requires the buyer to pay the generator when the strike price is higher than the spot price. With this type of contract, generators have the incentive to keep the spot price down (lest their payments to buyers increase).[16] Thus, generation unit owners that have sold forward financial contracts have a strong incentive to bid aggressively in the spot market in order to cover the forward financial commitment with actual physical sales of energy or capacity.[17]

No where is the evidence of the detriment caused by the buy-sell requirement more clear than in the case of San Diego Gas & Electric (SDG&E). In July 1999, San Diego completed the recovery of its stranded costs through the CTC. At that point, SDG&E was able to come out from under the retail rate freeze and pass-through the costs of its wholesale power purchases directly to its retail customers. Without the ability to hedge properly against volatile spot market prices, SDG&E's customers experienced a tripling of their electricity bills during the summer of 2000. Moreover, because the CPUC and state law mandated that SDG&E purchase its power out of the Cal PX, such purchases were deemed

14. FEDERAL ENERGY REGULATORY COMMISSION, Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities, at 5-9 (Nov. 1, 2000), *available at* http://www.ferc.fed.us/electric/bulkpower.htm [hereinafter FERC Bulk Power Report].

15. MARKET SURVEILLANCE COMMITTEE (MSC) OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR, An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Service Markets, at 7 (Sep. 6, 2000), *available at* http://www.caiso.com [hereinafter MSC 2000 Market Report].

16. FERC Bulk Power Report, *supra* note 14, at 5-9; MSC 2000 Market Report, *supra* note 15, at 9.

17. MSC 2000 Market Report, *supra* note 15, at 6.

prudent. Therefore, SDG&E had no incentive to minimize its wholesale power purchase costs.

(2) Retail Rate Freeze and CTC Recovery

A second fundamental policy flaw was that California's retail rate freeze and CTC recovery methodology conspired to eviscerate demand responsiveness to high energy prices and scarcity. The State imposed a $65/MWh retail rate freeze in order to ensure that retail customers did not pay higher rates during the nascent stages of restructuring.[18] At the same time, the CPUC believed that California's IOUs should be allowed to recover 100% of the stranded costs to transition to a new market structure. These stranded costs were to be recovered through the CTC as a surcharge to the price of power in the Cal PX. The effect of these policies was to ensure that demand response would be stifled.

In practice, this rate freeze/recovery mechanism was keyed solely to the Cal PX price, rather than any demand response to market signals. To the extent that Cal PX prices were low, the IOUs could recover their CTC more quickly. Conversely, to the extent that the Cal PX prices were high, the CTC recovery was slower. Any change in demand would have no bearing on rates to customers; only the speed at which the CTC was collected. Therefore, during times of scarcity of high prices, the retail rate freeze ensured that end-use customers would have no incentive to respond by decreasing demand.

Without appropriate demand responsiveness, the results are self-evident. When customers are unable to see the results of scarcity or higher costs on their retail bills, they have no incentive to reduce demand or consumption. Therefore, during peak periods, scarcity and higher prices are exacerbated. In a worst-case scenario, as we have seen in California, the utilities are forced to absorb billions in costs above the amount that they are permitted to pass-through under the retail rate freeze. This has pushed Southern California Edison Co. and Pacific Gas and Electric Co. to the brink of bankruptcy.[19]

(3) Separation of Market Functions

Another cornerstone of California's restructuring model was the principle of market separation. On a general level, California separated its energy markets from its transmission markets and created two separate

18. A.B. 1890 § 854, 1996 Cal. Stats. 854, codified, in relevant part, at CAL. PUB. UTIL. CODE §§ 330-398.5 (Deering 2001).

19. The retail rate freeze also stifled competition at the retail level. In and of itself, a rate freeze can effectively mitigate the effects of rate increases associated with a transition to competition. However, the legislature sought to give California's ratepayers a short-term benefit from restructuring by further ordering a rate reduction and then freezing the rates at the reduced level. The effect of the rate freeze was to ensure that no alternative power suppliers could compete to serve retail load. In other words, direct access was rendered inapplicable because the frozen rates that the IOUs were charging were lower than the rates that alternative suppliers could offer to serve California's retail load. There simply has been no competition at the retail level in California.

entities—the Cal PX and Cal ISO, respectively—to manage these markets. This general market policy has created a bevy of specific design, operational, and procedural flaws on a micro level.

Generally, the State believed that it was absolutely essential to separate the functions of the generation and transmission markets and vest such functions with two entities. The entities would then coordinate with one another to manage the total system. The rationale behind separating the two entities and their functions was set forth in the CPUC's Preferred Policy. The CPUC believed that separation would: (1) prevent the ISO from favoring pool transactions over bilateral or non-pool transactions in transmission access; and (2) provide an opportunity to develop transparent information about system operations and congestion that would mitigate potential discriminatory behavior.[20] In short, fears that the ISO would fail to act impartially caused the CPUC to disaggregate the two entities and their functions.

Honorable goals notwithstanding, this market separation has been identified as one of the major flaws with California's restructuring model.[21] The fact is the provision of transmission and generation must be coordinated and integrated with one another in order to serve load. First, in short term markets, there are no real differences between the dispatch of energy and transmission use.[22] The dispatch of generating units to provide energy dictates the use of the transmission system, and the operations of both generation and transmission must be determined and managed in a highly integrated fashion in order to maximize economic efficiency and reliable operations.[23] To vest the responsibility to manage bids, schedules of generation, and load with one entity and the responsibility of scheduling transmission to serve that same generation and load with another entity adds unnecessary complexity and discord to the process.

Second, market separation has created artificial requirements that are detrimental to the efficient and reliable operation of the system. For example, in order to support the Cal PX market, the California model requires each LSE to submit individual balanced schedules for load and generation to the Cal ISO.[24] In turn, such LSEs must self-provide or purchase the necessary ancillary services to support such balanced schedules.

20. Preferred Policies Governing Restructuring California's Electric Service Industry and Reforming Regulation, 64 CPUC 2d 1, 166 PUR4th 1, 1995 WL 792086, at *14 (Dec. 20, 1995).

21. *See generally*, JOHN D. CHANDLEY, SCOTT M. HARVEY, AND WILLIAM W. HOGAN, ELECTRICITY MARKET REFORM IN CALIFORNIA (2000) [hereinafter CHANDLEY, HARVEY, AND HOGAN].

22. *Id.* at 3.

23. CHANDLEY, HARVEY, AND HOGAN, *supra* note 21, at 3.

24. Cal ISO Tariff at section 2.2.7.2 (Oct. 13, 2000), *available at* http://www.casio.com/publicinfo/tariffs.

While a system operator must balance *aggregate* loads with generation due to constraints arising from physics, the balancing of individual loads and generation is neither necessary nor efficient.[25] The requirement forces the Cal ISO to coordinate transmission based on individual schedules, rather than coordinating loads and generation needs on a cumulative level. In addition, the requirement appears to exacerbate the capacity shortage in California by forcing the Cal ISO to procure greater amounts of regulation service to balance individual loads and forcing market participants to withhold capacity to provide adjustment bids to ensure balanced schedules. These market designs run counterintuitive to how electricity markets should operate.[26]

C. *Lack of Interregional Coordination*

In addition to the lack of support for competition and internal market design flaws, the California model failed to properly coordinate scheduling and operations of the Cal ISO with those of neighboring control areas. The California model also excluded the municipal transmission-owning utilities—roughly twenty-five percent of the California market. This lack of inter and intra-regional coordination has aggravated many of the market problems discussed above.

(1) Failed To Properly Integrate With Rest Of WSCC Interconnection

The transmission systems located within the Western Systems Coordinating Council (WSCC) are interconnected with one another. The Cal ISO is one of approximately thirty different control areas in the Western Interconnection that manage the various transmission systems. In order to maximize reliable operations throughout the West, these control area operators abide by similar reliability requirements as set forth by the WSCC. For example, members of the WSCC require similar levels of operating reserves and establish tie line ratings using similar criteria.[27]

Despite some efforts at regional coordination, numerous "seams" issues exist between the manner in which the Cal ISO operates its system when compared with its neighboring systems. In particular, the Cal ISO employs trading rules and scheduling timelines that are not synchronized with those of its neighbors. The fact is that the Cal ISO's scheduling and trading rules bear no resemblance to those rules in the rest of the WSCC. The result is that it is tremendously difficult to trade or schedule power from one control area to another. Power can remain trapped in one control area or another and reliability can suffer because power is not being scheduled or transmitted in a seamless manner.

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25. CHANDLEY, HARVEY, AND HOGAN, *supra* note 21, at 3.

26. *Id.* at 3.

27. Western Systems Coordinating Committee, Agreement and Bylaws (Dec. 7, 2000), *available at* http://www.wscc.com.

(2) Restructuring Ignored a Quarter of the Marketplace

Municipal utilities own approximately twenty-five percent of the generation resources that serve California. Municipal utilities serve over twenty-five percent of the load in California. They also own approximately thirty-five percent of the transmission import capability into California. These facts notwithstanding, the California restructuring model intentionally excluded municipal utilities from the restructured market.

As discussed above, the overriding goal of restructuring in California was to bring direct retail access to California's IOU customers as a response to high IOU retail electric rates. The municipal utilities were not contemplated in the plan, as their rates were significantly lower than those of the IOU customers. Moreover, municipal utilities transmission assets are newer than those of the IOUs and, thus, they have a higher embedded cost than the IOU transmission. Therefore, if municipal transmission had been rolled into the IOU transmission, transmission rates for IOU customers would have increased.

In addition, municipal utilities are non-profit, public interest organizations. Most are vertically-integrated utilities that own generation and transmission to serve their customers. Yet, restructuring in California required divestiture of generation and transmission assets so that the same utility did not serve load and operate generation. This failure to accommodate market participants with different organization structures discourages municipal participation in the Cal ISO.

Unfortunately, excluding municipal utilities from the overall restructured market has proven to be an unwise choice. It is now clear that California needs more transmission capacity. The Cal ISO has projected decreasing reserve margins and existing participating transmission owners are proposing to add substantial amounts of new transmission to the system. Although the Cal ISO does have coordination agreements with the municipal utilities to utilize their transmission, the Cal ISO's rights to this transmission are subordinate to the existing rights of the municipal utilities. These diminished rights simply do not provide the needed transmission capacity to the Cal ISO. In sum, municipal utilities have power and transmission that would benefit California. However, California's market structure has alienated municipal utilities and effectively denied them the opportunity to participate in the restructured market on fair, legitimate terms.

PART II.

The summer of 2000 solidified the fact that wholesale reforms were necessary to correct the California markets. The ISO, FERC, and CPUC all initiated investigations into market activities to determine the cause and potential solution to California's summer price spikes. By November 2000, the regulators concluded their preliminary investigations and identified many of the market flaws described in Part I of this article. In response, the FERC and the State of California have issued a number of orders and proclamations purportedly aimed at resolving the crisis.

A. *FERC's Response*

Beginning during the summer of 2000, a number of market participants brought complaints to the FERC, requesting major action to support the failing power markets in California. As discussed above, prices were skyrocketing and the LSEs were either passing along their increased costs to their customers or being forced to eat the costs. Some of these complaints blamed price caps for the failure of the market. Others alleged that generators exercising market power had inflated the price of power.

The FERC responded to these complaints by initiating an investigation into the wholesale bulk power market in California. On November 1, 2000, in an unusual move, the FERC released the staff report and a preliminary order proposing remedies for the market. The FERC then accepted written and oral comments on its proposed remedies. Finally, on December 15, 2000, the FERC issued its final order proposing definitive remedies for California's bulk power market. Since then, the FERC has refined its position and ordered certain entities to issue refunds for power sales at unjust and unreasonable rates.

(1) FERC's December 15, 2000 Order

The FERC's December 15, 2000 Order was the first significant action intended to deal with California's electricity crisis. Citing its interest in "protecting consumers, ensuring creditworthiness of market participants, and moving the Western markets toward the kind of rules that will sustain the electric industry in the long run," the FERC adopted remedies in its California Markets Proceeding designed generally to alleviate California electric price fluctuations and to ensure that sellers have incentives to offer electricity and construct new generation and transmission in California.[28] More specifically, the FERC adopted the following remedial measures it believed would correct some of the existing market flaws addressed *infra*.

a. Eliminate the Mandatory Cal PX Buy-Sell Requirement

As discussed above, California law required that the three IOUs buy all of their power needs from, and sell their owned-power into, the Cal PX. During the first two years of Cal ISO and Cal PX operations, the IOUs repeatedly requested that the CPUC limit this restriction. However, the CPUC was disinclined to loosen this requirement. Until August 2000, the CPUC limited the three IOUs' ability to enter into forward contracts to those forward contracts offered through the Cal PX Block Forward Market. As these contracts were of limited duration—up to one year—the

28. *San Diego Gas and Elec. Co. v. Sellers of Energy and Ancillary Servs. Into Mkts. Operated by the Cal. Indep. Sys. Operator and the Cal. Power Exch.*, 93 F.E.R.C. ¶ 61,294, at 61,981 (2000).

Cal PX Block Forward Market did not provide the IOUs with products to sufficiently hedge against spot market price volatility. In addition, the CPUC limited the total volume of the Cal PX Block Forward Market purchases in which each IOU could enter, further limiting the IOUs' hedging ability.

As of the November 1st FERC preliminary order, the CPUC had broadened the types of forward contracts into which the IOUs could enter, including permitting the IOUs to enter into bilateral forward contracts outside of the Cal PX. But, the CPUC maintained the restrictions on the IOUs' forward contract trading levels. In addition, the CPUC maintained its after-the-fact prudence reviews which likely dampened the IOUs' incentive to buy forward energy.[29] These facts were not lost on the market.

In its report on the Summer of 2000 price spikes, the ISO's MSC stated: "[w]e see little reason to perpetuate the [Cal] PX monopoly at this point in time, and hope that the CPUC will remove the remaining restrictions on quantities and locations at which UDCs can engage in forward contracting."[30] The MSC also noted that the Cal PX Block Forward Market products were not necessarily attractive products to the IOUs. Generators from outside of the ISO Control Area were either forced to offer products that fit within the Cal PX's standardized product forms or simply sell elsewhere. On the other side of the equation, a buyer with power needs between three and five p.m. for only certain days of the week could not obtain such specialized products in the Cal PX Block Forward Market.[31] Instead, the buyer was forced to either buy that energy on the spot market, or contract for more forward power through the Cal PX than was needed.

In response to these criticisms, the FERC's first move was to eliminate the mandatory Cal PX buy-sell requirement effective that day. Instead, the FERC encouraged the IOUs to move their purchase power needs to bilateral long-term contracts and adopt a balanced portfolio of contracts to mitigate their exposure to spot market prices. The FERC requested the State of California to take measures to remove its comparable Cal PX buy-sell requirement.

b. Established a Prudence Benchmark for Wholesale Bilateral Contracts

Because of its decision to eliminate the buy-sell requirement, the FERC ascertained that the Cal PX spot market price could no longer serve as a benchmark upon which one could base bilateral contract prices. Instead, the FERC decided to create a benchmark price based upon historical data that would be used to measure the reasonableness and prudence of bilateral contract prices. In its order, the FERC ascertained that a $74/MWh price for a five-year 7x24 product would be a workable

29. FERC Bulk Power Report, *supra* note 14, at 5-9.

30. MSC 2000 Market Report, *supra* note 15, at 7.

31. *Id.* at 9.

benchmark. Bilateral contract prices at or below that level would be presumptively just and reasonable.

c. Set Underscheduling Procedures and Penalties

The FERC further determined that underscheduling of load was creating an inflated need for the ISO to purchase power in real-time to balance such schedules. Therefore, the FERC mandated that market participants must schedule ninety-five percent of their load prior to real-time market, in an effort to limit real-time balancing energy purchases to only five percent of the market's total needs. Moreover, the FERC ordered that deviations in scheduling in excess of five percent of an entity's hourly load requirements would be subject to a penalty. To add further incentive not to underschedule, the FERC decided that underscheduling penalty revenues would be allocated to all loads that scheduled accurately.

d. Announced Market Monitoring and Price Mitigation Plans

The FERC further recognized that participants were taking advantage of the flaws in the market, to the detriment of the market as a whole. To address this concern, the FERC ordered the parties to engage in a technical conference to develop a monitoring and mitigation program with explicit thresholds and screens upon which market behavior can be analyzed. The parties were further ordered to define specific mitigation measures if those thresholds and screens are breached. The FERC required the parties to submit a proposed plan to the FERC by March 1, 2001. The FERC intended to solicit comments on the proposed plan and to implement final procedures by May 1, 2001.

In the interim, the FERC adopted a \$150/MW breakpoint price for generation bids into PX markets that it would use to monitor pricing. Sellers bidding at or below the breakpoint will receive the market clearing price. Sellers bidding above the breakpoint will receive their actual bids, but this price will not set the market clearing price. Moreover, the FERC decided that bids exceeding the breakpoint would be subject to reporting and monitoring requirements that will give the FERC an opportunity to investigate whether market power has been exercised. Unless a seller is notified that the FERC is investigating a particular transaction, refund potential on a transaction will end sixty days after the filing date of the report disclosing the transaction.

e. Approved the Formation of a New ISO Governing Board

The FERC also determined that the current ISO stakeholder board must be replaced with a non-stakeholder board. Therefore, the FERC ordered that on January 29, 2001, that "the ISO Governing Board members . . . turn over decision-making power and operating control to ISO management."[32] The FERC permitted the stakeholder board to act as

32. 93 F.E.R.C. ¶ 61,294, at 62,983.

an advisory committee and provide input to ISO management. Finally, the FERC stated its intention to establish a mechanism for involving state officials in the new board selection process. If the FERC and the state officials are unable to agree upon procedures to select a new board by April 27, 2001, the new ISO board will be selected using the procedures set forth in the FERC's November 1st Order.[33]

f. Additional Remedies and Requirements

Ordered the Development of Generation Interconnection Procedures for the ISO and IOUs. The FERC ordered the ISO and the three California IOUs to develop and file generation interconnection procedures applicable to the ISO Control Area by April 1, 2001.[34]

Adopted Refund Conditions. The FERC conditioned the authority to sell at "market-based rates on sellers remaining subject to potential refund liability through December 31, 2002. . . . [The FERC's goal was] to ensure just and reasonable rates" while measures are implemented to stabilize the California markets.[35] The FERC declined to clarify what further actions it might take with regard to imposing refunds for past transactions.

Committed to Generation Outage Investigations. The FERC committed to complement the generating unit outages investigations conducted by the CPUC and the ISO by asking its own staff to perform inspections.[36]

Announced a Technical Conference to Explore Additional Long-Term Solutions. Specifically, the FERC established technical conference procedures to address the following actions: "(1) the adoption of security-constrained unit commitment dispatch; (2) the use of simultaneous rather than sequential auctions; (3) the creation of an installed capacity market; (4) the establishment of reserve requirements; and (5) demand-side response programs."[37]

Directed the California ISO to Redesign its Congestion Management Process. The FERC directed the ISO to file with the FERC a congestion management process based on eleven Locational Pricing Areas (LPA) that were established using "engineering requirements, criteria and practices that guide real-time operation to ensure grid reliability."[38]

(2) March 9, 2001 Order Directing Refunds

As discussed above, the FERC's original position was that retroactive refunds for rates charged during the summer and fall of 2000 were not warranted. The FERC determined that, although the market had produced the ability for participants to exercise market power, it had been

33. *Id.* at 62,013-14.
34. 93 F.E.R.C. ¶ 61,294, at 62,020.
35. *Id.* at 62,010.
36. 93 F.E.R.C. ¶ 61,294, at 62,014-15.
37. *Id.* at 62,017.
38. 93 F.E.R.C. ¶ 61,294, at 62,017.

unable to identify any specific acts of the exercise of market power.[39] The FERC interpreted the Filed Rate Doctrine and the prohibition against retroactive ratemaking to be applicable in the case of market based rates. Additionally, the FERC found that because there is no precise legal standard for determining when a market-based rate is unjust and unreasonable, it was not able to order retroactive refunds.[40]

On a specific level, FERC found that:

> a variety of factors [had] converged to drastically skew wholesale prices under certain conditions: significant over-reliance on spot markets which by their very nature can produce dramatic price increases when supply is tight; significant increases in load combined with lack of new facilities as well as reduced availability of supply from out of state; chronic underscheduling; and lack of demand responsiveness to price.[41]

As such, although the FERC found the rates to have been unjust and unreasonable, it could not determine the exact cause for the rate level. The FERC did establish a refund liability on market based rates on a prospective basis, pursuant to section 206 of the Federal Power Act (FPA). The FERC set a "breakpoint" of $150/MW and attached refund liability to any rates charged above that breakpoint without sufficient justification.[42]

Pursuant to that aspect of the December 15 Order, the FERC ordered refunds for unjust and unreasonable rates charged during January 2001. In an order issued on March 9, 2001, the FERC found that certain transactions in the Cal ISO and Cal PX markets have not been demonstrated to be just and reasonable, absent the submission of further information supporting the rates charged in the transactions.[43] As a result, the FERC ordered sellers engaging in such transactions to refund approximately sixty-nine million dollars.

In reaching its decision, the FERC compared the rates charged to a proxy price developed to simulate the marginal price of power in a competitive market. Specifically, the FERC determined that the potential for market power was most likely during Stage 3 Emergencies—when the Cal ISO's operating reserve level falls below 1.5% of load.[44] The FERC developed a proxy price for power during Stage 3 Emergencies based upon assumptions that would exist in a competitive market. The FERC developed its proxy price of $273/MWh during the hours when a Stage 3 Emergency was in effect.[45] To reach this price, the FERC used a hypothetical simple-cycle combustion turbine unit (CT) with an assumed

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39. *Id.* at 62,019.

40. 93 FERC 61,294, at 62,031.

41. *Id.* at 61,998.

42. 93 F.E.R.C. ¶ 61,294, at 61,996-97. The FERC limited the refund liability to a term of 60 days. If upon review, the FERC does not issue a notice of refund within 60 days following the date the transaction is reported, the refund liability ends. *Id.*

43. *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs. Into Mkts. Operated by the Cal., Indep. Sys. Operator and the Cal. Power Exch.*, 94 F.E.R.C. ¶ 61,245, at 61,862 (2001).

44. 94 F.E.R.C. ¶ 61,245, at 61,862.

45. *Id.* at 61,862-63.

heat-rate of 18,073 Btu/kWh as the marginal unit for a competitive market.[46] The FERC then used the January midpoint price for natural gas into California and average NOx allowance costs and emissions rates, and typical variable operations and maintenance costs to develop its proxy price.[47]

Importantly, the FERC stated that sellers who charged rates exceeding the proxy price during Stage 3 Emergencies could avoid the refund obligation by supplying "further cost or other justification" for exceeding the proxy price.[48] The FERC provided no explanation as to what justification might suffice to avoid the refund requirement. Finally, the FERC asserted that it would develop a proxy price for each month through April 2001 using the above-cited indices. The FERC will then assign refund obligations in a similar fashion.[49]

(3) March 14, 2001 Order To Address Energy Supply and Consumption

The FERC's third major response to the crisis was an order issued on March 14, 2001, *Removing Obstacles To Increased Electric Generation And Natural Gas Supply in the Western United States*.[50] In this order, the FERC announced a number of actions that it planed to take pursuant to the FPA, the Natural Gas Act (NGA), the Public Utility Regulatory Policies Act (PURPA), and the Interstate Commerce Act, to help hasten the development of energy supplies to serve the West.[51] Recognizing that its actions will not immediately resolve California's electricity crisis, the FERC nevertheless believed that it could induce the development of increasing power supply through temporary actions (which will expire on December 31, 2001 unless otherwise noted):

- Require Cal ISO and the WSCC's transmission owners to prepare and file with FERC a list of grid enhancements that can be completed in a short time frame;

- Extend and broaden the temporary waivers for operating and efficiency standards and fuel use requirements for Qualifying Facilities through December 31, 2001;

- Waive the prior notice requirements and grant blanket authorization of market-based rates through December 31, 2001 for wholesale power sales from generation used primarily as back-up and self-support generation located at business within the WSCC;

46. 94 F.E.R.C. ¶ 61,245, at 61,863. The FERC obtained this data from filings made by the three IOUs in their 1998 FERC Form 1. *Id.* at n.5.

47. 94 F.E.R.C. ¶ 61,245, at 61,863.

48. *Id.*

49. 94 F.E.R.C. ¶ 61,245, at 61,863.

50. Order Removing Obstacles To Increased Electric Generation And Natural Gas Supply in the Western United States, 94 F.E.R.C. ¶ 61,272 (Mar. 14, 2001) (Docket No. EL01-47-000) [hereinafter Order Removing Obstacles] (FERC page numbers are not yet available).

51. *Id.* at 1.

- Authorize wholesale and retail customers to resell load reduction at wholesale at market-based rates;

- Waive certain requirements for wholesale customers under contract-based rates to facilitate wholesale demand-side management;

- Realign FERC staff to respond on an expedited basis to applications for new gas pipeline capacity;

- Investigate the potential to increase hydroelectric generation consistent with environmental protection.[52]

The FERC also seeks comment on a number of proposals that would also apply until the end of 2001. Specifically, the FERC seeks comment on providing "carrots" to investments made to increase transmission capacity in the form of premiums on equity returns and depreciation, and cost-recovery for non-capital investments, for projects that increase transmission capacity in the short term and for the immediate future.[53] Additionally, the FERC proposes to use its interconnection authority in the FPA and its certificate authority in the NGA to increase power and fuel supply to the West.[54] To respond expeditiously to the issues raised in its order, the FERC requested parties to comment on its order by the end of March 2001.

C. California's Response to the Crisis and to FERC

Since the electricity crisis in California began in earnest in May 2000, California's response has been inadequate. Regulators and legislators failed to recognize the market flaws discussed *supra* and to propose remedies for those flaws that fell within their purview. Moreover, California has failed to appropriately understand the ramifications of the situation in both the near and long-terms.

(1) Restrictions on Forward Market Contracts

Despite indications that excessive reliance on spot market purchases could be economically detrimental to utilities, the CPUC was very slow to react. Prior to the summer of 2000, the CPUC had resisted the IOUs' attempts to increase their ability to enter into forward market contracts.[55]

52. Order Removing Obstacles, *supra* note 50, at 2-3.

53. *Id.* at 3.

54. Order Removing Obstacles, *supra* note 50, at 4.

55. *See generally* FERC Bulk Power Report, *supra* note 14, at 4-5 n.11. Specifically the FERC Staff cited to cases brought by PG&E, Edison, and SDG&E for forward contracting authority. *See, e.g., Pacific Gas and Electric Co.*, D.98-06-076 (1998) (granting in limited capacity the right to use gas-indexed financial instruments to hedge gas costs for power production); and *Pacific Gas and Electric Co.*, D.97-08-058 (1997) (rejecting a request to hedge through the use of financial instruments). *See also Southern California Edison Co.*, D.99-07-018 (1999) (rejecting a request to implement a pilot program for bilateral agreements for energy and capacity purchases up to 2000 MW); *San Diego Gas & Electric Co.*, D.00-96-034 (2000) (denying a request for the limited authority to use financial instruments and forward contracts outside of the PX); and *San Diego Gas & Electric Co.*, D.97-12-088 (1998).

However, on March 16, 2000, the CPUC granted requests made by Edison and PG&E to purchase new energy products that the Cal PX began offering that spring.[56] In granting this request, the CPUC limited the IOUs' ability to use these products to the companies' net short positions—their total full service hourly demand less the utilities' provided generation.[57] In real terms, Edison could enter into Cal PX forward markets for up to 5000 MW per month and PG&E's limit was 3000 MW per month.

By May 2000, rates for SDG&E's ratepayers exposed to the pass-through of all energy market-based energy costs had doubled from the same time in 1999. By July 2000, the rates had tripled. During that same time frame, PG&E and Edison racked up enormous energy bills, the costs for which they could not pass-through to their ratepayers. In response, the CPUC granted several IOU requests made in July and August 2000 to loosen the limits on their ability to engage in forward hedging.[58] However, the CPUC retained the Cal PX buy-sell requirement in all other respects until the FERC's December 15th Order.

(2) CPUC Response to FERC's Orders Proposing Remedies

After the FERC issued its December 15th Order denying the IOUs retroactive rate relief, the IOUs filed emergency requests for rate increases to retail customers with the CPUC. Although the IOUs had requested higher rate increases, on January 4, 2001, the CPUC issued an Interim Opinion resolving the rate increase issue. Specifically, the CPUC implemented a surcharge per customer of one cent per kilowatt-hour, applied on a usage basis. This surcharge will result in a rate increase of approximately nine percent for residential customers, seven percent for small business customers, twelve percent for medium-sized commercial customers, and fifteen percent for large commercial and industrial customers.[59] The CPUC made the rate increase effective for a limited period of ninety days, and subject to refund.[60]

The immediate response to the CPUC's actions were disheartening. Both Edison and PG&E decried the rate increase as "too little too late."[61]

The CPUC first granted the IOUs' request to participate in the Cal PX Block Forward Market on July 8, 1999 through October 2000 to serve up to one-third of the IOU's hourly load per month. CPUC's Resolution E-3618 (1999). For the summer of 2000, the IOUs were permitted to use the Cal PX Block Forward Market in a limited capacity, subject to CPUC reasonableness reviews. *Id.* The CPUC permitted the utilities to enter forward contracts up to the following levels: SDG&E - 300-400 MW; PG&E - 2000 MW; and Edison - 1800-2000 MW. *See also* FERC Bulk Power Report, *supra* note 14, at 4-6.

56. CPUC Resolution E-3658 (2000).

57. *Id.*

58. FERC Bulk Power Report, *supra* note 14, at 4-6 - 4-7.

59. Press Release, California Public Utilities Commission, CPUC Grants PG&E and Edison a Electric Rate Increase on Refundable Basis (Jan. 3, 2001).

60. *Id.*

61. *Suppliers Say They Won't Sell Gas to PG&E*, GAS DAILY (Jan. 9, 2001).

Moreover, many have claimed that the CPUC has done little toward resolving the crisis.[62] In response, the CPUC took the position that retail rates need not be increased in the course of resolving the energy situation. However, on March 7, 2001, the CPUC authorized rate increases necessary to cover purchases of electricity in forward markets.

(3) California Government's Response to the Crisis

The Governor and State legislature had been silent on the issue of the power markets until the summer of 2000. At that point, the California government's sole action was to provide refunds and rate protection for SDG&E ratepayers. Subsequent to the FERC's November 1, 2000 preliminary order providing remedies to the California market, the State responded with strong opposition to the FERC's decision not to order retroactive refunds. Specifically, Governor Davis requested the FERC to order refunds to consumers that had been gouged by generators and marketers. Additionally, State regulators and legislators condemned the FERC's proposed soft price cap or "breakpoint" as an insufficient mitigation measure for unjust and unreasonable rates. Despite these views, the FERC upheld its proposed remedies in its December 15th Order.

Since the FERC issued its December 15th Order, Governor Davis has put the energy issue front and center on his agenda. Specifically, on January 8, 2001, in his State of the State address, the Governor called California's experiment in electricity deregulation "a colossal and dangerous failure."[63] To address this "failure," the Governor proposed an aggressive, multifaceted plan to repair the system. Specifically, the plan calls for the Governor to act to stabilize the power supply and the rates for power. In addition, the Governor has committed to take actions to promote demand-side management and conservation. Finally, the Governor pledged to promote the development of new generation supplies.

To stabilize rates and the supply of energy, the Governor signed Assembly Bill 1X on February 1, 2001, which permits the state to enter into long-term contracts on behalf of the IOUs' full-service customers. To expedite the contact negotiations, the Governor vested the California Department of Water Resources with the authority to negotiate such forward contracts on the IOUs' behalf. In addition, on February 1, 2001, the Governor issued two Executive Orders wherein the State seized the low cost Block Forward Contract positions entered into by Edison and PG&E in the Cal PX Block Forward Market.[64]

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62. In fact, the CPUC was questioned by State legislators as to why it had taken little action to alleviate the energy crisis.

63. The Honorable Gray Davis, State of the State Address (Jan. 8, 2001), *available at* http://www.video.dot.ca.gov/state/transcript.html.

64. *See, e.g.,* Exec. Order Nos. D-20-01 (Jan. 17, 2001) and D-21-01 (Jan. 17, 2001).

To promote conservation and demand-side management, the Governor has issued Executive Orders mandating consumer conservation efforts.[65] Moreover, in February 2001, the Governor proposed over $400 million in new conservation efforts. Specifically, the Governor has proposed initiatives and incentives designed to improve energy efficiency in existing homes and businesses and promote energy efficiency and conservation in the future.

Finally, to enhance California's generation supply, the Governor has taken measures designed to expedite the construction of new generation plants and the retooling of existing plants to maximize the output of existing plants. Specifically, Governor Davis signed Executive Orders D-26-01 and D-24-01 in order to maximize the output of existing generation plants by waiving timelines for retrofits and restarts, relaxing existing emissions standards, and increasing permissible operating hours. Additionally, Governor Davis signed Executive Order D-25-01 in an effort to expedite the process for siting and certificating new generation projects.

(4) Effort to Purchase IOUs' Transmission Lines

The most controversial step that Governor Davis has taken has been his effort to bail the IOUs out of their economic problems through the State's purchase of the IOUs' transmission assets. In February 2001, the Governor and the California legislature began to assess the viability of purchasing the IOU transmission assets in return for much needed cash. The State has touted its plan as a means of bringing the utilities back from the brink of bankruptcy. Moreover, the State seems to believe that by purchasing the IOUs' transmission assets, that the State will be able to exclude transmission in California from the FERC's jurisdiction.[66]

The response to the State's actions has been mixed. By February 23, 2001, Edison had reached a preliminary agreement to sell its transmission assets to the State for $2.76 billion. While negotiations between the State, SDG&E, and PG&E have continued respectively, PG&E has maintained steadfastly that it has no interest in selling its transmission to the State. As of the date that this article was published, no party has agreed formally to sell its transmission assets to the State.

PART III

There are certain truths in which the vast majority of market participants agree. (1) California is in desperate need of new investment in generation and transmission capacity. (2) There is no real demand-side responsiveness to high prices in California. (3) California's existing market structures must be redesigned. (4) California's ratepayers should pay rates that are just and reasonable. (5) California's IOUs are in dire financial

65. *See, e.g.*, Exec. Order Nos. D-18-01 (Jan 17, 2001) and D-19-01 (Jan. 17, 2001).

66. Office of the Governor, Press Release, Governor Davis Announces Recovery Plan for the State's Utilities (Feb. 16, 2001), *available at* http://www. Governor.ca.gov/state/govsite.

straits. However, in determining how to address these facts, market participants simply do not agree on the best methodology. To make matters worse, state and federal regulators seem unable to cooperate and coordinate a response to the current situation.

The intended purpose of restructuring was to bring the benefits of competitively priced generation to California's consumers. That goal must remain clear. To serve that goal and preserve the policy of restructuring, regulators and participants cannot take a one-dimensional approach. Rather, regulators and market participants must understand that the market contains various parties with various interests. For example, the IOUs must share some economic burden for choosing to take their stranded cost revenue and investing such in unregulated generation projects outside of California.[67] Regulators must understand that competitive generation suppliers are for-profit entities with fiduciary responsibilities to their shareholders. To require such entities to enter into power sales at lower than "market" value could subject such companies to shareholder derivative actions and will discourage investment and competition. Finally, consumers must understand that prices for power fluctuate. Power is generally cheaper in the winter and more expensive in the summer. Moreover, supply shortages and increased prices for natural gas inevitably cause electricity prices to rise. The remedies to fix California's market must be coordinated, balanced, holistic, and accommodating to those varied interests.

A. *Promote Adequate Supply of Generation*

California has finally realized that it needs new generation facilities. California also has realized that it should not force its LSEs to purchase 100% of their power supplies from the spot market. The FERC stated as much in its December 15th Order, and California has taken significant steps to address these concerns. However, other actions could serve to undermine the development of new power supplies.

(1) Promote Investment in New Generation

The Governor has issued Executive Orders and proposed plans to promote the development of new generation facilities in the State. And, providing incentives to develop new generation or retool and retrofit existing generation could help to bring much needed generation to California. However, simply easing the way for new generators to enter the market will not ensure an adequate supply of competitively priced generation.

In reaching its decision to restructure the electric industry in the first place, the CPUC acknowledged that investment in new generation and transmission had stalled in light of the unstable regulatory environment

67. Because the IOUs divested generation served, in part, to displace the need for transmission, had the IOUs invested such revenues into transmission in California, some of their current debt could have been avoided.

during the 1990s. Simply put, risk-bearing investors are less likely to invest in generation and transmission when regulatory uncertainty prevails. Unfortunately, actions by the FERC and the State have produced an unstable regulatory environment.

The FERC has proposed a "breakpoint" or soft price cap for generation. Other market participants and regulators believe a hard price cap is needed. In either case, the market cannot agree on what type of price or bid cap, if any, is needed. Generators argue that price caps frustrate competitive forces by insulating demand from taking action to respond to high prices—the basis of competition. Consumers and other market participants believe that price caps are necessary to limit exposure to high rates. Add to this the fact that the State has considered "nationalizing" the transmission assets in the state as well as some of the generation and power supply responsibilities. As a result, potential new generation investment likely will be stymied because those risk-bearing investors will have little certainty that the power they seek to sell at market-based rates will not be regulated by non-market forces.

The regulators and market participants must agree on a defined, unchangeable set of principles to mitigate the potential to exercise market power. Price caps, as currently applied are not working to protect the market or promote the development of generation supplies. Regulators and market participants simply must reach a consensus on what mitigation tools are appropriate and workable. Moreover, the market must establish a definitive end to regulatory mitigation tools so that potential investors are presented with a stable regulatory environment.

(2) Promote Investment in Transmission

Furthermore, in order to bring any new supply of generation to the market, California must upgrade its transmission system. During the 1990s, there was little significant investment in new transmission. Today, congestion and curtailments on the ISO grid are commonplace, especially on critical north-south transfer paths such as Path 15. The fact is that California's transmission system is over taxed. In order to meet growing demand and the hoped-for increase in new generation supply, California must upgrade its transmission system. California must increase its interface capacity at its borders. Additionally, California must upgrade the capacity of major internal north-south paths such as Path 15.

(3) Promote Balanced Power Supply Portfolios

California's PX buy-sell requirement was a total failure. It is imprudent for LSEs to purchase all of the their power supplies in any one market, be it long-term forward markets or spot markets. In order to properly balance price risks, LSEs should balance their power supply portfolios with a mixture of long-term, mid-term, and short-term supplies. By hedging appropriately, LSEs can maximize their ability to capitalize on low prices and minimize their exposure to price volatility. The FERC and the State should encourage utilities to commit to a balanced portfolio of long, mid, and short-term contracts over the next several years.

B. Provide for Meaningful Demand Response

For demand to be able to respond to fluctuations in price, demand must be able to see such price fluctuations. Because of the rate freeze in California, many retail ratepayers have no incentive to respond to high prices because they do not incur such high prices. In other words, the retail rate freeze had killed demand response. Therefore, California must end its retail rate freeze. California's retail customers can and will respond to high prices resulting from scarcity or otherwise if they are exposed to resulting high prices. To this end, programs that permit demand-side resources that reduces demand to sell their capacity into the market or pays demand-side resources a market-based rate to reduce demand are very effective tools.

Likewise, California should not try to protect its retail customers from sharing in the costs to recover from this crisis. In some measure today's high prices are being caused by legitimate factors such as *inter alia* weather, low hydro, increased demand, and a corresponding stagnation in the development of supply. The relatively higher costs of power resulting from these factors should be borne by California's ratepayers.[68]

C. Correct Core Flaws In Cal ISO Structure and Rules

Although generation supply and demand response issues must be addressed, the effect on the market will be limited severely unless California's broken market structures and rules are fixed as well. After-the-fact policing and corrections are inadequate. Markets must be designed appropriately in advance of full competition. Professor William Hogan and others have proposed a number of detailed market reforms that would cure California's market defects. On a general level, Professor Hogan believes that California should look to PJM as the appropriate restructuring model and ensure that the following actions are taken if the Cal ISO is to support workable competition:

(1) The Cal ISO must operate integrated transmission and energy markets. The "market-separation" rule serves only to confound problems with reliability and efficiency. Moreover, the market separation rule has not served its goal of protecting the markets from gaming.

(2) The Cal ISO must amend its congestion management rules to employ locational marginal pricing to price and settle all energy transactions in forward markets, and provide for firm transmission rights

68. The question of whether it is appropriate for ratepayers to pay for the costs that the IOUs have incurred above rate freeze levels is not simply answered. It seems clear that the IOUs recovered substantial stranded costs for the sales of their thermal generating facilities. Moreover, rather than investing a portion of such recovered costs in new transmission facilities necessary to substitute for the generation that was divested, the IOUs invested most of their recovered costs in their unregulated affiliates. However, it is likely that even under competitive circumstances, the prices during the second half of 2000 would have exceeded the rate freeze levels for the reasons set forth in this article.

to hedge against congestion-derived energy costs in different locations.

(3) The ISO operations and rules must be redesigned to correct perverse bidding and scheduling incentives. For example, the Cal ISO should consider simultaneous auctions for ancillary services and energy markets in order to optimize prices in such markets.[69]

In addition to Professor Hogan's proposed actions, the Cal ISO must coordinate with neighboring control areas and California's municipal utilities in order to ensure maximum reliability. The Cal ISO must correct seams issues with surrounding control areas, and ensure that ISO scheduling and bidding timelines are consistent with its neighbors. Moreover, the Cal ISO must take actions to encourage municipal utilities to join the ISO through targeted incentives and accommodations to the manner in which municipal utilities do business. Specifically, upon joining the Cal ISO, municipal utilities' transmission facilities should be fully rolled-into the overall Cal ISO transmission rate base as municipal transmission brings significant benefit and capacity to California.

D. California's Rates Should Be Just and Reasonable

The most divisive issue arising from the current energy crisis has been how to address the incredibly high prices that the utilities have been paying for power in California. Many believe that generators and marketers in California have gouged the market for billions of dollars. Others believe that the rates charged have reflected the current cost of generating power in California. In either case, no one disagrees that FERC is obliged to ensure that rates are just and reasonable as required under the Federal Power Act. The actions discussed above, if taken in whole should produce just and reasonable rates on a going-forward basis.

One issue of significant import is the FERC's treatment of rates dating back to the summer of 2000. In the FERC's orders proposing remedies, the FERC determined that it was unable to provide retroactive refunds for unjust and unreasonable costs incurred prior to the December 15, 2000 date of the FERC order. The FERC relied on section 206 of the FPA to support its position.[70] Specifically, the FERC held that under section 206 of the FPA, it can issue only prospective relief. The FERC's retroactive refund analysis stated that "section 206 does not expressly afford retroactive refund relief for rates covering periods prior to the filing of a complaint or the initiation of a Commission investigation even if the Commission determines that such past rates were unjust and unreasonable."[71] The FERC also relied upon the Filed Rate Doctrine in support of its position. Specifically, the Filed Rate Doctrine "forbids a regulated entity [from] charg[ing] rates for its services other than those properly filed with the appropriate regulatory entity."[72]

69. William W. Hogan, KSG Faculty Presentation at 10 (Feb. 14, 2001).

70. *See generally* 93 F.E.R.C. ¶ 61,121, at 61,376.

71. *Id.*

72. Arkansas Louisiana Gas Co. v. Hall, 453 U.S. 571, 577 (1981).

The FERC applied the refund provisions in FPA section 206 and the Filed Rate Doctrine to this case despite the fact that the rates at issue in California are market-based rates. The FERC asserted that the FPA makes no distinction between cost-based rates and market-based rates.[73] In fact, the FERC asserted that the FPA does not provide any guidance as to how the FERC is to establish a just and reasonable rate.[74] Ultimately, the FERC found that the refund provisions of sections 205 and 206 of the FPA must apply equally to cost-based and market-based rates.

The FERC would seem to be correct in its reasoning. The FPA is clear that rates can only be changed in accordance with either section 205 or section 206. Section 205 is inapplicable in this case because the actions which gave rise to the FERC remedy orders were filed under section 206. On its face, section 206 only provides for prospective refunds.

Additionally, the limited circumstances under which the FERC can order retroactive refunds in a section 206 proceeding are inapplicable to the circumstances in this case. The FERC can order retroactive refunds in the case where a utility has charged impermissible costs through a formula rate on file with the FERC.[75] But, no formula rate (or comparable situation) is at issue here. The FERC can also order refunds where judicial review of the FERC decisions requires the FERC to do so; another inapplicable precedent to the instant case.[76] Finally, the FERC can issue retroactive refunds for serious violations of the FPA.[77] However, the FERC stated in its December 15th Order that it could find no evidence of a specific exercise of market power. Therefore, the FERC cannot order refunds on the basis of an FPA violation. In short, the FERC's analysis of its inability to issue retroactive refunds seems quite sound.

Another important issue concerns FERC's ability to require a refund obligation on a going-forward basis. To that end, the FERC did establish that all market-based transactions exceeding the $150 breakpoint would be subject to refund on a prospective basis.

As noted above, on March 9, 2001, the FERC issued an order directing refunds. In that order, the FERC found that certain transactions in the Cal ISO and Cal PX markets had not been demonstrated to be just and reasonable.[78] As a result, the FERC ordered sellers engaging in such transactions to either justify the prices charged for their transaction to the FERC's satisfaction, or refund approximately sixty-nine million dollars to the market.

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73. 93 F.E.R.C. ¶ 61,121, at 61,376.

74. *See, e.g.*, FPC v. Hope Gas Co., 320 U.S. 591, 602 (1944).

75. *See, e.g.*, *Appalachian Power Co.*, 23 F.E.R.C. ¶ 61,032, at 61,088 (1987).

76. *See generally* 93 F.E.R.C. ¶ 61,121, at 61,381.

77. *Id.*

78. *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs. Into Mkts. Operated by the Cal., Indep. Sys. Operator and the Cal. Power Exch.*, 94 F.E.R.C. ¶ 61,245, at 61,862 (2001).

The FERC has chosen an interesting approach to the issue of refunds in this case. Pursuant to section 206 of the FPA, if the FERC determines that the existing rates, charges, or classifications are unjust, unreasonable, or unduly discriminatory or preferential, it must determine and order a just and reasonable rate. In its Refund Order, the FERC seems to imply that parties will be able to justify rates that otherwise would be unjust and unreasonable. No similar standard exists in the FERC case law.

California's ratepayers, IOUs, and officials have decried FERC's denial of retroactive refunds. Moreover, FERC's unprecedented approach to the issue of prospective refund obligations most certainly will not sit well with generators and other market suppliers. As a result, the issue of FERC's treatment of refunds seems destined for further action in the court of appeals.

E. Will Nationalizing the California Grid Help Abate the Crisis?

Governor Davis and the California legislature have pursued the idea of purchasing the IOUs' transmission systems. Their motive is twofold. First, the Governor and legislature believe that it is important to keep the IOUs out of bankruptcy. They further feel that purchasing the transmission assets will provide the utilities with much needed cash that will assist their financial situations. Second, they would like to remove the transmission system from the FERC's jurisdiction. This motive has arisen because of the finger-pointing that has taken place between the FERC and the State, assigning blame for the current crisis. Yet, California's plan may rely on faulty logic with respect to both motives.

According to the preliminary agreement between California and Edison, the parties have agreed that Edison will sell its transmission to the State for $2.76 billion. However, Edison's current outstanding bill for costs incurred purchasing power, far exceed that amount. Thus, from a simplistic perspective, if Edison is still unable to repay all of its defaulted obligations, it may still be unable to avoid bankruptcy. The same theory applies to both PG&E and SDG&E.

As for the Governor and legislature's second motive, it is not clear that if the State purchases the transmission assets that the State will be able to avoid the FERC's jurisdiction. On a general level, in discharging its jurisdictional duties under the Federal Power Act, FERC can issue policies such the Open Access Transmission policy of Order No. 888[79] and the Regional Transmission Organization policy in Order No. 2000,[80] both

79. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, [Regs. Preambles 1991- 1996] F.E.R.C. STATS. & REGS. ¶ 31,036, 61 Fed. Reg. 21,540 (May 10, 1996); *order on reh'g.*, F.E.R.C. STATS. & REGS. ¶ 31,048, 62 Fed. Reg. 12,274 (Mar. 14, 1997).

80. Order No. 2000, *Regional Transmission Organizations*, [Regs. Preambles] F.E.R.C. STATS. & REGS. ¶ 31,089, 65 Fed. Reg. 809 (Jan. 6, 2000), *reh'g denied*, Order No. 2000-A, 90 F.E.R.C. ¶ 61,201, 65 Fed. Reg. 12,088 (Mar. 8, 2000).

of which can implicate California's ownership of former jurisdictional assets. For example, these facilities currently are under the FERC's jurisdiction. As a result, the FERC can set conditions on any transfer of the assets to the State, including mandating participation in a regional transmission organization subject to the FERC's jurisdiction.

Under sections 211 and 212 of the Federal Power Act, the FERC can order non-jurisdictional entities to interconnect and provide comparable service if such non-jurisdictional entities desire service from jurisdictional entities. These provisions were refined in Order No. 888's reciprocity and comparability principles. Because California is highly integrated and interconnected with the Western Interconnection, many of the transmission lines in California are vital to the interconnected operations of utilities to the north and to the east. And, California relies upon transmission from the north and the east at different times of the year for vital imports of power. If California is to continue to be able to rely upon imports of power from neighboring jurisdictional entities, California will be forced to provide what transmission it has available under terms and conditions that the FERC must approve. Therefore, the Governor's plan to eliminate the FERC's jurisdiction through the purchase of the IOU transmission is dubious.

CONCLUSION

The FERC articulated succinctly that it believes that the California markets are seriously flawed.[81] California has taught us some important lessons on restructuring. The biggest lesson to learn from the California experience is to get the foundation right. Regulators must establish a market design based upon sound logical policies. Finally, for restructuring to succeed the state and federal regulators must work in concert to promote unified policies.

We do not have the luxury of starting from the beginning in California. We must act now to fix the market on a going-forward basis. Unfortunately, the remedies that have been proposed and ordered to *post facto* fix the market propose to fix certain problems and not others. Other proposed remedies seek to vilify certain market participants and protect others without taking a holistic view of the market and how to fix it. In the end, the FERC, California, and the market participants must put aside politics and blame, and work together to redesign the market so that it serves the ultimate goal—providing reliable, efficient, and less expensive power to consumers—by ensuring a viable and competitive market for retail customers, wholesale customers, generators, marketers, system operators, and transmission customers alike.

81. 93 F.E.R.C. ¶ 61,121, at 61,984.