UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company	Docket No. EL00-95-000
Investigation of Practices of the California Independent System Operator and the California Power Exchange	Docket No. EL00-98-000
Public Meeting in San Diego, California	Docket No. EL00-107-000
California Power Exchange Corporation	Docket No. ER00-3461-000
California Independent System Operator	Docket No. ER00-3673-000

RESPONSE OF THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA TO NOVEMBER 1, 2000 ORDER, AND REQUEST FOR REHEARING AS TO ISSUES WHICH HAVE BEEN FINALLY DETERMINED

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Pursuant to the November 1, 2000, Order ("the November 1, Order") issued in the above-docketed proceedings, the Public Utilities Commission of the State of California ("CPUC") provides its response to the November 1, Order. The CPUC is a constitutionally established agency charged with the responsibility for regulating electric corporations within the State of California. In addition, the CPUC has a statutory mandate to represent the interests of electric consumers throughout California in proceedings before the FERC.

The November 1, Order is unusual in that it proposes numerous remedial actions but is vague as to whether the November 1, Order is final as to those actions. Several measures are, for example, described as "Proposed Immediate Measures." November 1 Order, slip op. at 24. Consequently, to the extent that the November 1, Order is not final, the CPUC provides its comments, arguments, and supporting evidence with respect to the issues set forth below. In addition, because it is unclear with respect to several issues whether the November 1, Order is final, the CPUC requests rehearing as to each issue discussed below. The request for rehearing is not meant to suggest that the November 1, Order is or should be final on any issues as to which FERC did not intend it to be final, or to foreclose debate on any issue prior to the issuance of a final order. Rather, the CPUC seeks simply to ensure that it does not waive the procedural protection of rehearing by erroneously assuming that an issue is not final.

I. INTRODUCTION

The CPUC is concerned that the November 1, 2000 order fails to provide meaningful relief to Californians who, as the FERC's order recognizes, have spent billions more for power in recent months than ever before, paying prices that are not justified on the basis of industry costs or any other measure. The price mitigation measures proposed in the November 1, Order simply do not go far enough to stop the bleeding and may in fact aggravate existing problems. California is now in the seventh month of paying for unprecedented and unreasonable wholesale prices, and the effects are taking a serious toll on California residents, businesses, and utilities. PX prices on November 14, when the FERC Commissioners held a public conference in these dockets in San Diego, ranged from $114 at 1:00 a.m. to $219 at 7:00 p.m., averaging $163 for the day—exceeding year-ago November prices of $26 by a factor of six.

In this regard, it appears that the FERC Staff Report which provides the basis for the November 1, Order is incomplete, and underestimates the extent to which "market" prices are not those that any expert would predict in a competitive market. The CPUC thus reiterates its earlier request that FERC provide California with interim price relief, and requests that FERC conduct additional proceedings in these dockets to develop long-term solutions.

II. PRIOR PROCEEDINGS IN THESE DOCKETS

These dockets commenced with a complaint filed by San Diego Gas & Electric Company ("SDG&E") on August 2, 2000. SDG&E presented compelling evidence that the California markets in June and July of this year were producing prices which vastly exceeded prices in any prior period, were disconnected even from increased production costs, and could not be considered just and reasonable. For instance, SDG&E demonstrated that the average operating costs of a typical Southern California gas-fired generating unit, at then-prevailing prices, had risen to about $60. By contrast, average total energy and Ancillary Services prices for June were approximately $166/MWh, and prices for July averaged $118/MWh. See CPUC Motion for Interim Relief filed October 19, 2000, Attachment 1. SDG&E further demonstrated that when demand in the ISO grid exceeded approximately 33,000 MW, prices diverged wildly from costs. For relief, SDG&E requested that FERC modify suppliers' market-based rates to restrict bids $250.

FERC issued a preliminary order on the complaint on August 23, 2000. San Diego Gas & Electric Company, 92 FERC ¶ 61,172 (2000). FERC ruled that it had an insufficient record on which to modify sellers' rate schedules, but that it was appropriate to investigate both whether public utility sellers' rates were just and reasonable and, more broadly, the ISO and PX market structure. The August 23 Order noted that if and when FERC found rates to be unjust and unreasonable, it may establish new rates on the basis of the record. Id., at 61,605-606.

In response to continued exorbitant prices, various entities including the CPUC filed pleadings seeking interim relief in mid-October. The CPUC and others presented evidence that the market continued to produce unjust and unreasonable prices through August and September. Average August prices were approximately $182/MWh (or 18¢/kwh) for all hours, including off-peak hours. See CPUC Motion for Interim Relief filed October 19, 2000, Attachments 1, 2. According to the ISO, overall prices for energy and Ancillary Services for all hours averaged $126/MWh in September 2000, compared to $38/MWh in September 1999, on an increase in load of 2.5%.[1] High prices continued through October. According to PG&E, the PX price charged to residential consumers for the four week period ending October 31 was $.143/kWh, or $143/MWh.[2]

Relief sought in the several mid-October pleadings included requests for imposition of a $100 price cap (Joint Motion of PG&E, Edison, and TURN), imposition of load-differentiated price caps and mandatory, regulated forward contracts (CPUC Motion for Interim Relief), and a package offered by the ISO management centering on a $100 price cap with certain exceptions and mechanisms for reducing underscheduling in the forward markets (ISO Offer of Settlement). TURN and UCAN separately filed comments recommending additional market reforms (TURN/UCAN Comments in Response to FERC's Meeting in San Diego).

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[1] See http://www.caiso.com/docs/09003a6080/08/fa/09003a608008fa93.pdf.

[2] See http://www.pge.com/customer_services/business/tariffs/e1102004.html (rate E1).

III. SUMMARY OF COMMENTS AND ISSUES PRESERVED FOR REHEARING

A. Summary of Comments

The CPUC is concerned that FERC's proposed remedies are insufficient, and takes issue with the evidence and analysis underlying the proposals. The CPUC further agrees with FERC's conclusion that based on the record presented to date, FERC "is obligated under FPA section 206 to take action" to ensure just and reasonable rates in the future. November 1, Order, slip op. at 3.

Unfortunately, the FERC staff report acknowledges having inadequate time and data, yet makes conclusions which tend to legitimize claims of increased costs and underestimate the extent of market power. The CPUC's preliminary staff analysis—conducted under similar conditions of imperfect data and inadequate time—suggests that claims of tight supply and increased costs, while real, are overstated and explain less of the increased costs than FERC staff concludes. The CPUC's analysis suggests that market power played a much greater role in the summer's prices than appears to be acknowledged in the Staff Report. At a minimum, additional data and analysis are necessary to resolve these discrepancies. Moreover, there is some evidence of attempts to intentionally manipulate the market, which should also be further investigated.

FERC has the authority to impose refunds retroactively and should do so. The CPUC's preliminary analysis shows that as much as $4 billion of PX costs are attributable to market power for the period between June and September. FERC should set hearings on this issue.

The CPUC is concerned that the proposed price mitigation measures will be ineffective to constrain market power under current market conditions. The soft cap proposal amounts to no cap at all during periods of high demand. Indeed, California wholesale markets have experienced extraordinary prices during periods of moderate demand, suggesting that the soft caps will be ineffective during many if not most pricing periods. In addition, since current forward markets reflect high spot prices, it is not reasonable to rely on forward markets to reduce pressure on, and prices in, spot markets under current market conditions without taking action to ensure that forward prices are reasonable. The CPUC has suggested "vesting" contracts as a transitional mechanism to accomplish this goal. Also, the Order improperly limits refund liability to opportunity costs, effectively making market power-inflated opportunity costs equivalent to just and reasonable rates under the FPA. Finally, the proposal to charge an underscheduling penalty to loads, but not to generation, is unreasonable, particularly in light of evidence of generators' refusal to bid sufficient supply into the PX, at any price, to meet forecast load.

In light of the finding that the markets are often not competitive and that prices have been unjust and unreasonable, FERC's rejection of hard price caps is unlawful. Similarly, FERC's proposal now to abolish all price mitigation measures in 24 months is premature and offered without any evidence that markets will be reasonably competitive in 24 months. California is working to facilitate necessary new infrastructure, energy efficiency, and demand responsiveness.

FERC should recognize that the state has an appropriate role in crafting long term solutions to the issues raised herein, and modify its proposals to accommodate that role, with respect, for instance, to the elimination of the buy/sell provision and the determination of ISO governance structures. In addition, elimination of the buy/sell has significant implications for retail ratemaking in California which must be addressed. Finally, FERC should require that market monitoring reports required of the ISO, PX and market participants be provided to the CPUC.

FERC should hold further proceedings in these dockets to resolve factual disputes, determine long term solutions, and decide refund issues. In the interim, as requested in the CPUC's October 19 Motion for Interim Relief, FERC should impose load differentiated price caps and mandatory, regulated forward contracting as interim measures until disputed factual issues are resolved and appropriate long term solutions are developed. Without further action by the FERC, Californians will be vulnerable to continued prices that are unjust and unreasonable and market machinations that undermine system reliability.

B. Requests for Rehearing

The following decisions in the November 1, Order are clearly final decisions, and the CPUC requests rehearing of each decision on the grounds that each violates the FPA, is arbitrary and capricious, not the product of reasoned decisionmaking, and not based on substantial evidence: (1) the decision to close the record in these proceedings on November 22, 2000, as discussed in Section X, below; and (2) rejection of the proposed PX price cap, rejection of the request to extend the ISO price cap, decision to terminate the $250 price cap after December 31, 2000, and rejection of the ISO's adoption of load differentiated price caps, as discussed in section V.C, below.

In addition, it is unclear whether the following issues have been finally decided, and the CPUC requests rehearing of each issue to the extent it is indeed final, on the grounds that each violates the FPA, is arbitrary and capricious, not the product of reasoned decisionmaking, and not based on substantial evidence: (1) imposition of the "soft cap" proposal, as discussed in section V.A, below; (2) elimination of all price mitigation measures after 24 months, as discussed in section V.D, below; (3) failure to provide for refund liability prior to October 2, 2000, as discussed in section VI.A, and VII, below; (4) limitation on refund liability to amounts in excess of opportunity costs, as discussed in section VI.B, below; (5) determination of the governance of the ISO and PX, as discussed in section VII.A, below; (6) elimination of the buy/sell requirement, as discussed in section VIII.B, below; (7) failure to require reporting of market monitoring information to state agencies, as discussed in section VIII.C, below; and (8) proposal to charge an underscheduling penalty to loads, as discussed in section IX.A, below.

IV. STATEMENT OF FACTS: THERE IS SUFFICIENT EVIDENCE OF THE EXERCISE OF MARKET POWER TO WARRANT EFFECTIVE REMEDIAL ACTION

The November 1, Order finds that rates in the ISO and PX markets for short-term energy and Ancillary Services have been unjust and unreasonable. FERC concludes that there is "clear evidence that the California market structure and rules provide the opportunity for sellers to exercise market power when supply is tight and can result in unjust and unreasonable rates," and that "there is evidence suggesting that sellers had the potential to exercise market power (where market power is defined as prices above short-run marginal cost) this summer." However, FERC further concludes—erroneously in the view of the CPUC—that the record upon which it issued the November 1, Order did not support findings of specific exercises of market power. November 1, Order, slip op. at 3.[3] FERC made these findings despite relying on a Staff Report which is admittedly incomplete, and which suggests the need for additional investigation.

The CPUC commends the FERC staff for its effort under difficult time and data constraints. However, the CPUC's preliminary analysis of data currently available suggests that the FERC Staff Report contains errors regarding market fundamentals which tend to overestimate claims of increased costs which are not supported by all the facts. <u>See</u> <u>e.g.</u>, November 1, Order, slip op. at 36-37 ("the Staff Report lists a number of factors that legitimately led to higher prices last summer"). For all the generators' claims of increased costs, there is no documentation in the record of any supplier's actual costs, so far as the CPUC is aware. Certainly no supplier has yet been willing to provide the CPUC with documentation of its claimed costs. The Chairman's post-hearing questions, which observe that suppliers' "broad claims are anecdotal," appropriately

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[3] Taken together, these findings indicate that the <u>prices</u> <u>alone</u> this past summer demonstrate that market power has been exercised, resulting in unjust and unreasonable rates. Such a finding is amply supported by the evidence presented in the SDG&E complaint, the CPUC Motion for Interim Relief, and the Joint Motion.

request data documenting actual production costs and alleged opportunity costs. This is the type of material which suppliers have thus far refused to provide to the CPUC.

The CPUC's efforts to present evidence have been hampered by poor access to data, and like FERC staff, inadequate time to fully analyze the data that has been received. In this section the CPUC discusses preliminary evidence and analysis it has developed date, as set out more fully in the CPUC's evidentiary submissions filed herewith. These materials consist of the Prepared Testimony of Paul Clanon and Accompanying Exhibits (Exhibits PUC-1-12), and the Prepared Testimony of Michael Scheible of the California Air Resources Board (Exhibit PUC-13).

As discussed further below, the CPUC's preliminary analysis suggests that the Staff Report overestimates the impacts of increases in production costs (chiefly natural gas and NOx), and overstates the extent of supply constraints during the summer of 2000. This evidence raises important questions regarding the conclusions in the November 1, Order, and points toward substantially greater exercise of market power during Summer 2000 than the Staff Report would

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indicate. In addition, the CPUC presents evidence which, at a minimum, creates a triable issue of disputed fact as to the extent of market manipulation which occurred in Summer 2000.[4]

The CPUC's preliminary assessment demonstrates that, even after taking into account increased gas and emissions costs, costs in the PX Day Ahead market alone exceeded a baseline marginal cost estimate for the period of June to September 2000, by over $4 billion. See Exhibit PUC-6. The CPUC's analysis assumes that Summer 1999 prices accurately reflected the marginal costs of incremental generation necessary to meet load, and adjusted 1999 prices to accommodate changes in volume, gas prices and NOx prices. This calculation produced an adjusted marginal cost baseline figure for summer 2000 to which actual PX costs were compared. The CPUC received ISO market data too late to reflect an analysis of the ISO data in this filing. The CPUC's preliminary analysis suggests that gas and NOx cost increases account for about 40% of the increase in summer 2000 prices. Id.; see also, Hildebrandt, Analysis of Market Power, October 26, 2000, slide 3 (showing thermal generators bidding three to five times their actual costs during a summer super peak hour) and slide 6 (showing 85% of California's thermal generation to have costs below $70 at $5.50 gas price).[5]

The FERC Staff Report characterizes Summer 2000 as a period where weather-related demand increases combined with reduced supply due to reduced net imports and higher plant

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[4] The September 6, 2000, Report of the Market Surveillance Committee, alone, establishes a brutally effective exercise of market power in the month of June. MSC, An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets, available on the ISO web site at http://www.caiso.com/docs/09003a6080/07/dc/09003a608007dc78.pdf. The ISO calculates that the total energy cost in the California ISO and PX markets in June 2000 was $3.171 billion. ISO, Review of Market Performance for May-August 2000, August 31, 2000 (available on the ISO web site, www.caiso.com). The MSC calculated that 64.6%—two-thirds!—of those costs were above and beyond conservatively estimated competitive market costs. That is to say, in June alone market power was exercised to the tune of $2.05 billion. Unfortunately the MSC has not yet published a similar analysis of the entire summer. Market costs in July and August amounted to over $6 billion. Even if one assumes that market power diminished by 50% as the summer progressed—a highly questionable assumption—it is not unreasonable to expect a complete investigation to show that these costs include an additional $2 billion attributable not to scarcity or increased costs, but to simple market power. And of course, high prices continued through the month of October. At a minimum, the MSC report establishes a necessity for FERC staff to complete the investigation that it has begun.

[5] Available on the ISO web site at http://www.caiso.com/docs/09003a6080/09/47/09003a6080094797.pdf.

outages to create a very tight supply and demand balance, which created sufficient scarcity to lead to significantly higher market clearing prices. However, in its discussion of each of the factors behind summer 2000 supply and demand conditions, the FERC readily acknowledges that it does not have a complete picture of these events.

First, FERC staff acknowledged that actual hourly peaks in California dropped slightly in 2000 compared to 1999 (although demand rose elsewhere in the West). See Exhibit PUC-3. In addition, the CPUC's preliminary results show that, particularly at low load levels, prices are not well correlated with demand. Put another way, prices were high even when demand was not. See Exhibit PUC-7.

Second, although imports were down from summer 1999, imports remained steady from May 2000 through August 2000, at a time when purported exports were rising. This calls into question the both the extent to which decreased imports played a role in supply adequacy, and the conclusion that increased exports were driven by reductions in the ISO price cap. As FERC staff acknowledged, it raises the prospect that much of the increase in "exports" were not exports at all, but were destined for California through Out-of-Market purchases. See Exhibits PUC-3 and PUC-8.

Third, while increases in plant outages were seen, they are not well explained. FERC staff seeks to explain the increased outages primarily by reference to the age of divested thermal units, but the increased outage levels—particularly increases since 1996—are significant enough to raise questions as to whether they are adequately explained by age. See Exhibits PUC-3 and PUC-4. Even FERC staff acknowledges that more investigation is necessary before it is reasonable to conclude that increased outages were caused by bad luck or old age, rather than by intentional withholding or inadequate maintenance. Id. The CPUC's preliminary analysis also provides a basis for further investigation of some of the reasons for the scarcity of supply witnessed this year, including the potential that some generator outages reflect attempts to manipulate the market. See Exhibit PUC-5 (original filed under seal).

The FERC staff report attempts to identify the economic factors that contributed to high electricity prices during the summer of 2000. Among the identified factors are high natural gas prices and high NOX compliance costs. For example, NOx RECLAIM credits increased from "approximately $6.00/lb in May to over $40/lb at the end of August."[6] The FERC Staff Report estimates that for a combined-cycle gas generator, which emits approximately 1 pound of NOx per MWh, this translates to an increase in operating cost due to RTC costs from $6/MWh in May to $40/MWh in August. For a combustion turbine gas peaking unit that emits more than 2 pounds of NOx per MWh, this translates to an increase in operating cost due to RTC costs from $12/MWh in May to $80/MWh in August. The Staff Report points out that during times of peak demand, the market clearing price is set by the least efficient gas plants which also are the plants with the highest NOX per MWh emission rates. As such, assuming a 16,000 Btu/KWh heat rate and a natural gas price of $5.00/MMBtu, the staff concludes that the operating cost of the marginal gas units during peak demand approached $160/MWh in the month of August.

However, the FERC Staff Report does little to shed light on how frequently the market needed FERC staff's hypothetical combustion turbine. For example, while this plant may have been in the market setting the market clearing price during times of peak demand, it is unclear whether this hypothetical plant was in the market and setting California's high electricity prices during the shoulder and off-peak periods. The CPUC is aware that some of these plants were emission constrained, and as such would have bid their opportunity costs—the high expected peak prices—during shoulder and off-peak periods. However, the FERC staff report does not discuss this issue and therefore does not provide information on how significant the emission

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[6] "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer

constraint was in explaining high shoulder and off-peak prices. The prices for emissions credits does not explain wholesale market prices that have exceeded $160/MW.

In addition, as the Testimony of Mike Scheible of the California Air Resources Board ("CARB") demonstrates, the effect of emissions credit costs on electricity prices has been considerably overstated. See Exhibit PUC-13. First, the RECLAIM program is in place only in the Los Angeles area. Only Los Angeles area plants thus had emissions credit costs in 2000. In other areas of the state, emissions credits are not traded. CARB states that RECLAIM has added some costs for "up to 20% of California's generating capacity," i.e. those plants located in the Los Angeles area.

Second, the reported emissions credit ("RTCs") costs exceed the actual prices. Although, as the November 1, Order states, some transactions did take place in August at $40/MW, and in September at prices of up to $48/MW, these prices were the exception rather than the rule. Trading also took place in August at a price of $.01. The average RTC price in August was $12.80 for credits expiring in June 2000 and $9.63 for credits expiring in December 2000. In addition, the maximum price at which RTCs traded in July, well after PX and ISO prices had reached and sustained extraordinary levels, was $10. Average RTC prices in July were around $6, and average prices in June—when electricity prices averaged $166—were about $4. In addition, it appears that even Los Angeles area units that had exhausted their allocations continued to operate and provide power this summer. Presumably they did so because they believed the price they were receiving for power was sufficient to cover any RTC acquisition or penalty costs they could face in the future.

One point that is clear from the data provided by the Air Resources Board is that RTC prices did not begin to rise steeply until August. RTC prices never exceeded $10/MW until

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2000 Price Abnormalities", November 1, 2000, pp. 3-21.

August. Thus, emissions costs simply do not have much explanatory power for the extraordinarily high prices in June, or the merely extremely high prices in July.

As indicated briefly above, there is evidence which is suggestive of efforts to manipulate the markets this summer, including the increases in unit outages, and increases in exports even while imports held steady (at a time when ISO OOM calls were rising). In addition, analysis performed for the CPUC in the context of PG&E's proposal to divest its hydro facilities demonstrates that small amounts of withholding of high cost generation by generation owners whose portfolios also include inframarginal generation can increase market clearing prices profitably for the owner. Generation ownership portfolios exist in California that strongly resemble the generation portfolio's modeled in the study found to be capable of exercising market power. See Exhibit PUC-9.

The CPUC has no reason to believe that the proposed "soft" price cap proposal will adequately constrain the market power and extraordinary prices of the past several months. The "soft cap" proposal appears to rely on the theory that forward contracting will reduce pressure on spot markets, and that the pay-as-bid feature will limit the impact of residual pressure on the spot markets. However, other elements of the November 1, Order will increase suppliers' incentives to withhold generation until the last moment, thus increasing the upward price pressure on forward contracts. In contrast, preliminary results based solely on PX data indicate that application of the ISO's load differentiated price cap proposal adopted October 26 to summer 2000 PX data show that the load-differentiated price cap would have reduced PX prices this past summer substantially See Exhibit PUC-10. See also Hildebrandt, Proposals for System-Wide Market Power Mitigation, October 26, 2000[7] (analysis of various potential price mitigation proposals based on historical price data shows potential cost savings of $1 billion to $2 billion).

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[7] Available on the ISO web site, at http://www.caiso.com/docs/09003a6080/09/47/09003a6080094796.pdf.

The November 1, Order is critical of the CPUC for failing to provide PG&E, Edison, and SDG&E with sufficient ability to hedge their risk. In particular, the November 1, Order states that CPUC rules require about 80% of utility load to be obtained from the day-ahead and day-of markets. The CPUC is committed to providing utilities with necessary flexibility, and has been responsive to IOU requests for flexible buying authority. See Exhibits PUC-11 and PUC-12. The CPUC has thus far limited the IOUs' forward contracting authority, in or outside of the PX, to their "net-short" position, i.e., the quantity of load that they cannot satisfy with their retained generation assets (including QFs). In Southern California Edison Company, et al., Resolution E-3683, 2000 Cal. PUC LEXIS 630 (July 6, 2000) (approving PG&E's and SCE's participation in expanded Block Forward Markets ("BFM")), the CPUC noted that "[t]he primary reason for limiting BFM participation is to protect ratepayers from the risk of over-procurement. Limiting BFM participation also reduces opportunities for speculation and the exercise of market power. Conversely, the primary reason for increasing the limit in BFM participation is to allow utilities to hedge against known contingencies and increases in demand that could result in price spikes. Our task is to balance these competing concerns." Id. at 6. It continues to be the case that the CPUC must balance these competing concerns in considering expanded forward contracting authority. Past experience with long term contracts in both gas and electric markets suggests the CPUC must consider whether and which forward contracts in wholesale markets will look good over the next several years.

V. THE ACTIONS AND PROPOSALS IN THE NOVEMBER 1, ORDER IMPROPERLY REMOVE THE LIMITED PRICE MITIGATION MEASURES PREVIOUSLY IN EFFECT AND ERRONEOUSLY REPLACE THEM WITH UNPROVEN MEASURES LIKELY TO BE INEFFECTIVE

A. FERC's "Soft Cap" Proposal is Insufficient to Constrain Acknowledged Market Power

The central price mitigation measure proposed by the November 1, Order is the modification of the ISO and PX auction rules to provide for a market clearing price mechanism for bids up to $150, and a pay-as-bid auction for bids above $150. While well intentioned, this scheme, which has been referred to as a "soft cap," is insufficient to constrain the market power which FERC has acknowledged exists in the California markets. In light of FERC's finding that rates are unjust and unreasonable, this proposal fails to satisfy FERC's obligation under § 206 to establish rates which are just and reasonable.

1. The Modified Auction Will Permit Excessive Bids and Thus Unjust and Unreasonable Prices

The modified auction mechanism would not prohibit bids above $150. Rather, it would simply provide that such bidders would be paid their bid price rather than a market clearing price set by such bids. The theory appears to be that the impact of such bids will be limited by the change in auction mechanisms, since not all suppliers will receive the highest bid. November 1, Order, slip op. at 39. As explained further below, the pay-as-bid aspect of the proposal could provide some relief from high prices under some circumstances. The FERC's proposal, however, limits this aspect of the proposal to bids over $150. But this "cap" will permit at least some suppliers to make excessive bids and receive unjust and unreasonable prices.

Under the Federal Power Act, however, unjust rates are unjust even if they are not as unjust as they might be. That is, despite FERC's finding that prices have been unjust and unreasonable, and despite its obligation to thus ensure reasonable prices in the future, the proposed modification to the auction mechanism continues to permit suppliers to charge and receive unreasonable prices. Under the high demand conditions which produce bids over $150, California will be left with no upper bound on prices at all, despite the fact that FERC now agrees that such tight demand conditions confer market power on virtually all sellers, and have resulted in unjust and unreasonable rates. FERC seeks to justify this result by stating that the proposal will allow prices to reflect the cost of scarcity, November 1 Order, slip op. at 43, but fails to distinguish between "scarcity" pricing reflecting the need to operate higher cost units which then set the market price, and "scarcity" pricing driven by the ability of suppliers to set prices well above the costs of any unit in the market. The latter result is not permitted by the FPA.

2. The Soft Cap Proposal is Unworkable Because Other Elements of the Proposal Will Increase Incentives to Withhold Supply

The "soft cap" proposal appears to rely on the theory that forward contracting will reduce pressure on spot markets, and that the pay-as-bid feature will limit the impact of residual pressure on the spot markets. The CPUC supports expanded forward contracting at just and reasonable rates, and called on FERC, in the CPUC's Motion for Interim Relief, to impose a requirement on sellers to enter into mandatory forward contracts with load serving entities. In recognition of the fact that high spot market prices—driven, in the CPUC's view, by market power enhanced by tight supply conditions—had dramatically impacted forward markets as well,[8] the CPUC proposed medium-term mandatory contracts at a FERC-regulated rate.[9] By contrast, although

[8] The Order acknowledges that "higher spot prices in turn affect the prices in forward markets." (Order, slip op. at 38.

[9] A reasonable proxy for rates determined through lengthy rate case litigation could, for instance, be based on forward market prices during a period when the market appeared to be operating competitively. See New York Independent System Operator, 93 FERC ¶ 61,142 (November 8, 2000), slip op. at 12.

relying heavily on forward contracting for the success of the soft cap proposal, the November 1, Order does nothing to ensure the availability of forward contracts at reasonable prices.

To the contrary, other elements of the November 1, Order will increase suppliers' incentives to withhold generation until the last moment, thus increasing the upward price pressure on forward contracts. In particular, the November 1, Order proposes to: (1) eliminate any upper bound on prices (e.g. the current $250 cap) after December 31, 2000; and (2) penalize loads, but not generation, which schedule with less than 95% accuracy in the forward markets. While each of these proposals is discussed in greater detail below, their likely impact on the soft cap proposal deserves comment here. Both of these features will tend to increase the profitability of the spot market for generators, particularly in high demand periods.

The summer of 2000 amply demonstrated that when demand is even moderately high in California and the West, suppliers have the ability to set the price at whatever price cap may be in effect. If there is no price cap in effect, suppliers can be expected to take advantage of that fact. All indications are that next summer will be characterized by similar, if not tighter, supply conditions. Under these circumstances, if the upper bound on prices is removed, suppliers' expectations of spot prices will increase accordingly. This can only serve to increase the price pressure on forward markets.

The proposal to charge an underscheduling penalty to loads but not to suppliers will have similar effects. The proposal simply tilts the supply and demand relationship further out of balance. Demand for forward products will increase. Loads will rationally pay up to $99 above the expected spot price to avoid the underscheduling penalty. The expected spot price will already be inflated by this summer's high prices and the removal of the "hard" price cap. This is a recipe for continued unjust and unreasonable prices.

3. The Soft Cap Proposal Reflects a Misunderstanding of Market Rules

The \$150/MW soft cap proposal appears to reflect a misunderstanding of the uniform market clearing price mechanism, and may produce unintended effects. FERC proposes a modification to the PX and ISO auctions that establishes a \$150/MW breakpoint whereby any participant who submits a bid at or below this amount will be paid the market clearing price. In addition, any participant who submits a bid above this amount will be paid as-bid and will be required to submit to FERC a report that provides the background information that supports this bid.

FERC's proposal to bifurcate the PX bid function and auction into a section that gets paid the highest market bid up to, and including, \$150/MW, and a section that gets paid as-bid produces an uncertain pricing outcome. This is because each market participant submits to the PX auction a piece-wise linear portfolio bid function and not a step function that is defined over a specific generation resource unit.[10] Moreover, the quantity awarded and price paid to each market participant is determined by the intersection of his sloped supply bid function and the net demand facing him.[11]

For example, suppose bidder A bids 1000 MW at \$100/MW and 500 MW at \$200/MW (See Figure 1). And, suppose that bidder B bids 1000 MW at \$150/MW. Lastly, suppose that the PX auction results in the market clearing quantity of 2050 MW. Under FERC's proposal, it is

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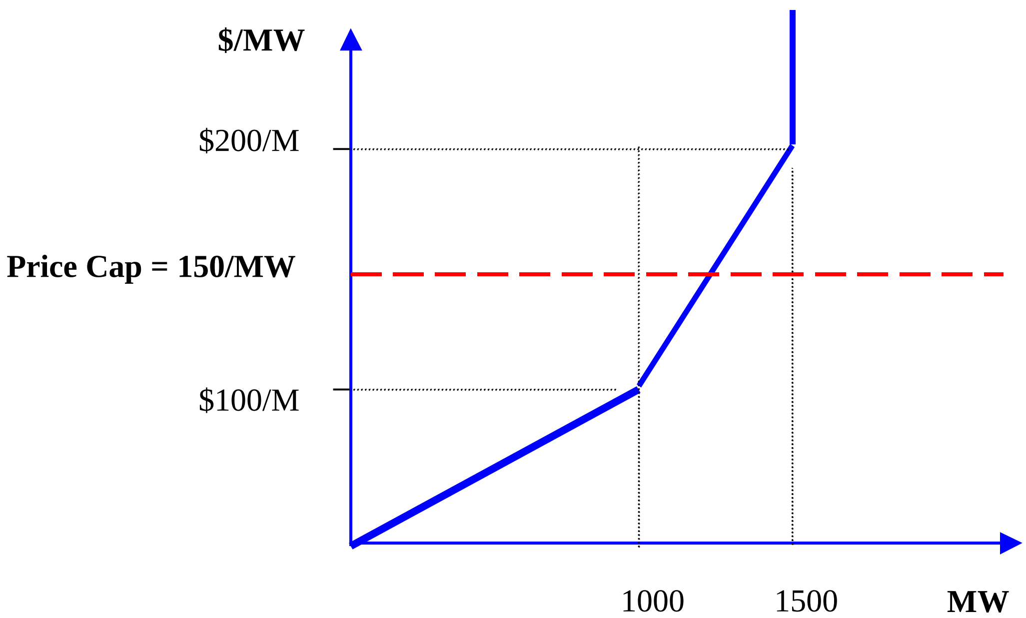
[10] Under current market rules, suppliers do not have to identify the generation source when they submit their bids to the PX. This rule may enhance the ability of suppliers to exercise generation market power, and certainly complicates the task of monitoring the markets for anomalous behavior. FERC, the new PX board, and state decisionmakers should look closely at this market feature and consider eliminating it.

[11] In Footnote 85 in the Order, the Commission offers the example of a highest selected bidder asking \$160/mwh, with the second highest bidder asking \$75/mwh and concludes, "the supplier bidding \$160 would be paid \$160/mwh for the amount it supplied, and the market clearing price for all other sellers would be set at \$75/mwh." However, under a piece-wise linear bid function construct, the market-clearing price may well be above \$75, while the \$160 bidder could receive an amount far below \$160.

clear that both bidder A and B would each receive $150/MW for a 1000 MW block of energy. However, it is unclear what bidder A would be paid for the additional 50 MW of energy awarded.

Figure 1 – Bidder A



If bidder A provided a step bid function to the PX, as it does to the ISO auctions, then it would be clear he would receive an as-bid payment of $200/MW for the 50 MWs. That is, whether bidder A succeeded in selling 50 MW or 500 MW, he would be paid $200/MW for the amount sold. However, since bidder A provides a piece-wise linear bid function to the PX, it is unclear as to what payment it would receive under the soft cap proposal. Under the existing PX pricing scheme, this additional energy would be priced at $150/MW, the market clearing price. However, under the soft cap proposal, since bidder A offered the 500 MW block at $200/MW, it would apparently receive $200/MW for the 50 MWs. FERC's approach thus could actually increase the price received by such bidders, and thus overall market costs.

4. The Soft Cap Proposal Might Undercut the Ability of Utilities to Hedge Prices with Retained Generation

The soft cap proposal could negatively affect the UDCs' ability to hedge high prices with their retained generation. That is, it presents an imbalance between the opportunities of utilities and non-utility sellers, an imbalance that could be extremely costly for the utilities and, following the rate freeze, their customers. Divestiture of thermal generation units has made the UDCs net buyers in most or all hours. Nevertheless, PG&E and Edison have retained substantial hydroelectric, nuclear, and QF portfolios. SDG&E has rights to a share of the output of the San Onofre Nuclear Generating Station, plus some contractual power. Currently, most of these resources are bid into the ISO and PX markets as price takers (with the exception of some hydroelectric units), to ensure their dispatch. Revenues from these resources have been substantial this summer, as utility-owned generation has received the high market clearing prices. These revenues serve to sharply reduce the UDCs exposure to high market prices.

If the UDCs continued to sell their retained generation into the PX under the soft cap proposal, UDC-owned generation would be subject to the same operating restrictions that result in their being bid as price takers in the markets, but their revenues would be limited to $150/MW. On moderate and high demand days, however, a UDC purchasing through the PX will pay an average price that is higher than $150 (the average of the pay as bid prices). The combination of a restricted market clearing price and the pay-as-bid element of the soft cap proposal could thus serve to diminish the value of the UDCs retained generation both to the UDCs (under the rate freeze) and to customers.

B. FERC Cannot Rely on Forward Markets to Address the Dysfunctional Market without Additional, Effective, Mitigation Measures

The CPUC agrees with FERC's assessment that the California IOUs will need additional flexibility in managing risk on behalf of their shareholders and customers. The CPUC has been responsive to IOU requests for authority to engage in forward transactions. See Exhibits PUC-11 and PUC-12. However, FERC has not put in place measures to ensure that prices in forward markets will be reasonable. Forward markets are influenced by spot markets. When spot market prices are inflated by the exercise of market power, forward prices will track those inflated prices. Under current market conditions, any plan which seeks to mitigate spot market pricing by relying, as FERC's proposal does, on forward contracting, must also address the reasonableness of forward markets.

In its October 19, 2000, Motion for Interim Relief, the CPUC proposed a means of addressing this issue: medium term regulated forward contracts, modeled on vesting contracts with a proven track record in other restructured markets. See CPUC Motion for Interim Relief at 8. Similar mechanisms have been used in New York, for instance, where utilities which have divested generation were required to buy back power from the divested units under long term contracts during a transition period.

Some such mechanism is necessary because forward markets do not ignore spot markets. Rather, forward prices track increases in the electricity spot market. For example, as noted by the FERC staff report[12], while forward market prices were much lower earlier in the year, resulting in summer 2000 prices well below spot market prices for those who hedged, forward contract prices began to escalate significantly after April 2000 at Palo Verde, COB, and Mid-Columbia.

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[12] November 1, 2000 Staff Report to the FERC on Western Markets and the Causes of the Summer 2000 Price Abnormalies, page 3-13 –3-15.

According to Power Markets Week, forward contracts at the Western hubs transacted in May through August 2000, increased significantly along with the rest of the Western market prices for electricity.[13] Forward prices at Palo Verde and COB entered into at the end of April 2000 for the third quarter were in the $60/MWh to $70/MWh range. In June forward prices for the third quarter were $100-$140/MWh. By July forward prices for August were $140-$150/MWh. November forward prices for the third quarter 2001 are approximately $130/MWh.

While there have been recent reports of longer-term transactions at somewhat lower prices, there is little reason to believe that heavy reliance on the forward market under current market conditions will serve to produce just and reasonable prices.

C. The Rejection Of Hard Price Caps at a Time When FERC Has Made Finding That The Market is Unworkable and Produces Unjust and Unreasonable Prices Violates § 205 and Farmers Union

The November 1, Order erroneously rejects various proposals for "hard" price caps. First, in Docket No. ER00-3673-000, the ISO has requested an extension of its purchase price cap authority, set to expire November 15, 2000. Second, in Docket No. ER00-3461, the PX has requested similar purchase price cap authority. Both requests are expressly denied by the November 1, Order. November 1, Order, slip op. at 50. Third, the November 1, Order rejects the load-differentiated price caps adopted by the ISO at its October 26 Board meeting. Id., at 17, n. 34. Fourth, the November 1, Order imposes a temporary $250 price cap, but provides that it shall be in effect only for 60 days, through December 31, 2000. Id. at 50.

Each of these decisions is erroneous for the same, simple reason: the FPA does not permit FERC to abandon consumers to an unworkable marketplace. In the November 1, Order, FERC concludes that market conditions have resulted in unjust and unreasonable rates, particularly

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[13] Power Market Week May 1, 2000, June 19, 2000, July 10, 2000, and November 6, 2000.

during high load conditions. It is "well accepted" that an agency responsible for ensuring reasonable rates in industries with anti-competitive conditions may not rely on the market to accomplish that goal. Air Transp. Ass'n of America v. DOT, 119 F.3d 38, 41 (D.C. Cir. 1997), citing Federal Power Comm'n v. Texaco, Inc., 417 U.S. 380, 397-99, (1974); Farmers Union Cent. Exch. v. FERC, 734 F.2d 1486, 1509-10 (D.C. Cir. 1984), cert. denied, 469 U.S. 1034 (1984) ("Farmers Union"). FERC has acknowledged this basic truth, saying, "where companies have market power, market-based rates are not appropriate." Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities, Policy Statement on Incentive Regulation, 61 FERC ¶ 61,168, at p. 61,587 (1992).

The November 1, Order recognizes, as it must, that tight supply conditions in the West during high demand periods confers market power on suppliers, and further recognizes that there is at present in California "little demand responsiveness to price." November 1, Order, slip op. at 38. As the ISO stated in its August 10, 2000 "Request to Extend Price Caps," where "consumer responsiveness and new entry are severely limited, however, as in today's electricity markets, the ability of suppliers to exercise market power under tight supply conditions cannot be limited by competitive market forces." See Attachment C to the CPUC's Motion for Interim Relief.

There is no factual basis upon which FERC can reasonably conclude that the California markets are sufficiently workable to produce reasonable prices in the absence of hard price caps. To the contrary, FERC's Staff Report and the November 1, Order both conclude that market power has been exercised, rates have been unreasonable, and there is substantial potential for unreasonable rates into the future. FERC's findings were based on incomplete data and faulty interpretation of some data that it did have, which tended to bias the Staff Report against finding that market power was exercised.

As set out above, the CPUC's preliminary analysis estimates that increased production costs in 2000 compared to 1999—mainly increases in natural gas prices and emissions credits costs—explain only about 40% of increased PX prices. See also, Hildebrandt, Analysis of Market Power, October 26, 2000, slide 3 (showing thermal generators bidding three to five times their actual costs during a summer super peak hour) and slide 6 (showing 85% of California's thermal generation to have costs below $70 at $5.50 gas price).[14] The CPUC's preliminary analysis also provides a basis for further investigation of some of the reasons for the scarcity of supply witnessed this year, including the potential that some generator outages reflect attempts to manipulate the market. See Exhibits PUC-4, PUC-5 (original filed under seal) and PUC-8.

Moreover, the PX market monitoring committee saw evidence of attempts by the new generation owners to exert market power in the summer of 1998. See, PX Market Monitoring Committee, Second Report on Market Issues (March 10, 1999).[15] The CPUC's analysis also demonstrates that suppliers with generation portfolios like those of current California suppliers could in fact profitably seek to withhold output and raise market clearing prices. See Exhibit PUC-10. There is little question that the exercise of market power explains a very substantial proportion of this year's costs, amounting in the CPUC's preliminary analysis to over $4 billion.

Under such conditions, if there is no upper bound on prices the exercise of market power can be expected to have very severe consequences for California business and consumers. California experienced a prelude to what it can expect under the soft cap proposal in June 1998. Then, suppliers recently granted market-based rate authority drove Ancillary Services prices up to $9,999 on one occasion. Reports at the time indicated that the exploiting supplier's bid, and the

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[14] Available on the ISO web site at http://www.caiso.com/docs/09003a6080/09/47/09003a6080094797.pdf.

[15] Available on the PX web site at http://www.calpx.com/regulatory/fercfilings/Second_Report_Market_Issues.pdf

resulting price, was limited only by what turned out to be an erroneous belief that the ISO's software could not accept bids exceeding four digits.

Sellers will not be constrained by erroneous beliefs about ISO software when the summer of 2001 arrives. Unless there is a "hard" price cap, five, six and seven figure bids will be submitted, and the ISO will have little choice but to accept them. The ISO's Department of Market Analysis ("DMA") has found that in many hours where shortages do not exist, suppliers "routinely bid a significant part of their capacity at the former $750 price cap," demonstrating that during high load periods "many bidders are pivotal, meaning that their bids are guaranteed to be selected and thus they can influence the market clearing price through their actions." Id., at 5. When demand on the ISO system exceeds 40GW the DMA has concluded that "there is no constraint on how high [generators] might raise their prices in the absence of price caps." (See ISO Department of Market Analysis, "Price Cap Policy for Summer 2000," available on the ISO's web site, www.caiso.com).

FERC's decision to remove all upper bounds on prices after December 31 is not only illegal but, quite simply, unfathomable. It ignores both the facts and the law. Regardless of whether or not FERC adopts the "soft cap" proposal in its anticipated December Order in these dockets, there can be no dispute that FERC cannot remove all limitations on prices, as proposed, under the current market conditions. This aspect of the November 1, Order, if no other, must be reversed.

D. The Proposed Removal of All Price Mitigation Measures After 24 Months is Arbitrary and Capricious, Not the Product of Reasoned Decisionmaking, and Not Based on Substantial Evidence

FERC's proposal to "sunset all price mitigation" (November 1 Order, slip op. at 47) after 24 months is arbitrary and capricious and not the product of reasoned decisionmaking. The

November 1, Order simply postulates, without any evidentiary basis, that "24 months is sufficient to restore order to these markets." Id. If there is any basis for this proposal, it appears to be to provide an incentive to California decisionmakers to ensure that generation and transmission capacity expansions are sited and built promptly, and that mechanisms to enable customers to respond to prices will be identified, installed, and utilized. See e.g., November 1 Order, slip op. at 47 ("At the end of our 24-month window . . . prices will be the product of the informed choices Californians have made on supply and demand and will reflect the true scarcity cost which they place on electric generation.").

FERC also states that its proposed 24-month window "will afford the state and local agencies a window to streamline, facilitate and accelerate the siting of needed generation and transmission." November 1 Order, slip op. at 63; Staff Report at 5-7. Of course, as Governor Davis and CPUC President Lynch have stated in FERC's recent public conferences in these dockets, the state of California is well aware that capacity expansion is necessary. The Legislature and Governor have moved strongly to ensure that new generation capacity is sited both expeditiously and in a manner consistent with both federal and state environmental laws. FERC fails to take into account, however, the construction cycle inherent in building power plants—projects that have recently been approved by the California Energy Commission ("CEC") will not be built until the 24-month period is complete.[16] Recent legislation also requires the CPUC, working with the ISO, to identify and resolve transmission constraints promptly.[17] Additional legislation requires the CPUC to conduct studies to determine the effectiveness of

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[16] See e.g. Moss Landing, approved by CEC 10/2000, online date 10/2002. In addition, the Staff Report inaccurately describes the siting process. See Staff Report at 5-7 ("AB 970 centralizes in the CEC determinations would normally be made by numerous state and local agencies"). The CEC has had centralized control over the permitting for large thermal plants since its inception; AB 970 streamlines this permitting process for certain facilities. The Staff Report also cites a superceded provision of California law to the effect that the process "requires the applicant to select at least three possible sites for the facility, including at least one that is not a coastal site." California law has not required three sites for approximately 10 years.

[17] AB 970, Stats. 2000 Ch. 329.

various metering and related technologies in fostering price responsive demand among smaller consumers.

The CPUC certainly shares FERC's hope that 24 months will be sufficient time to create competitive electric market conditions in California. FERC's exhortations aside, however, the FPA does not permit FERC to pre-announce that a workably competitive market will emerge on a schedule set by federal regulators. Algonquin Gas Transmission Co. v. FERC, 948 F.2d 1305, 1313 (D.C. Cir. 1991)("an agency's unsupported assertion does not amount to substantial evidence"). If anti-competitive conditions remain after 24 months, despite the best efforts of all parties, FERC will not be able to rely on market forces to produce just and reasonable rates. Air Transp. Ass'n of America v. DOT, 119 F.3d 38, 41 (D.C. Cir. 1997), citing Federal Power Comm'n v. Texaco, Inc., 417 U.S. 380, 397-99, (1974); Farmers Union Cent. Exch. v. FERC, 734 F.2d 1486, 1509-10 (D.C. Cir. 1984), cert. denied, 469 U.S. 1034 (1984). This is all the more true where FERC is acting under its § 206 authority to "fix" rates after finding that market-based rates were unjust and unreasonable.

FERC took the proper approach in an order issued only days ago. In New York Independent System Operator, Inc., 93 FERC ¶ 61,142 (November 8, 2000), FERC determined that the New York ISO's ("NYISO") spinning reserve markets remained non-competitive. Accordingly, FERC extended a previously imposed sellers' bid cap, plus mandatory bidding requirements, "until such time as NYISO demonstrates that the non-spinning reserves market, in all situations, is workably competitive." Id., slip op. at 12. In the NYISO case, FERC properly recognized that the market must be found to be workably competitive before it can legally rely on market mechanisms alone to produce just and reasonable prices. Only after a demonstration that the market is workably competitive will FERC remove the bid caps and mandatory bidding requirements. This is just the approach that the CPUC has requested in these dockets: first, make an affirmative, evidentiary finding that markets are workably competitive and only then remove measures designed to protect consumers from anti-competitive market conditions. Any other approach is both unreasonable and inconsistent with federal law.

E. FERC Should Impose Load-Differentiated Price Caps As An Interim Measure

Rather than FERC's untested scheme to modify the auction mechanism, and its illegal proposal to remove all "hard" price caps, FERC should impose a load-differentiated price cap mechanism. The CPUC proposed one such mechanism in its October 19 Motion for Interim Relief. The ISO Board adopted another such mechanism at its October 26 board meeting. The November 1, Order rejects these proposals with a single conclusory sentence, stating that such proposals "introduce significant complexity into a market that is already in dire need of simplification." November 1 Order, slip op. at 41. While there is little doubt that the markets are extremely complex, the level of complexity posed by a load-differentiated price cap proposal pales in comparison to other aspects of the market. FERC's abrupt dismissal of these proposals reflects its failure to take them seriously, and represents a decision which is arbitrary and capricious, not the product of reasoned decisionmaking, and not based on substantial evidence. Algonquin Gas Transmission Co. v. FERC, 948 F.2d 1305, 1313 (D.C. Cir. 1991)("an agency's unsupported assertion does not amount to substantial evidence").

The load-differentiated price cap concept is superior to a static price cap. Although it provides no guarantee that prices will approximate actual costs, it sets the price cap at each level on the basis of the actual operating costs of units on the margin. It is superior to the $150 soft cap proposal both because it permits higher prices when higher cost generating units are necessary to meet system demand, and because it effectively contains prices at levels reasonably related to costs in both high and low load conditions. The CPUC's preliminary analysis indicates that load-differentiated price caps along the lines of those adopted by the ISO in October, if applied to Summer 2000 prices, would have saved Californians close to $2 billion. See Exhibit PUC-11. The ISO presented a similar analysis at its October 26 board meeting. See also Hildebrandt, Proposals for System-Wide Market Power Mitigation, October 26, 2000[18] (analysis of various potential price mitigation proposals based on historical price data show potential cost savings of $1 billion to $2 billion).

FERC's rejection of the load differentiated price cap proposals and endorsement of the soft cap proposal is tied to its concern that rates not be below a level necessary to stimulate new supply. November 1 Order, slip op. at 4. The courts have permitted FERC to consider "non-cost" factors in the setting of just and reasonable rates, "primarily in recognition of the need to stimulate new supplies." Consumers Union v. FPC, 510 F.2d 656, 660 (D.C. Cir. 1974). However, FERC cannot simply set an arbitrary price on the unsupported theory that such a price is necessary to draw out new supply. Algonquin Gas Transmission Co. v. FERC, 948 F.2d 1305, 1313-1314 (D.C. Cir. 1991) (speculation as to costs of facilities which may be built in future does not justify pricing decision). If FERC is to set prices in this § 206 proceeding at a level justified, in part, on the need to attract new supply, FERC has the burden of "calibrat[ing] the relationship between increased rates and the attraction of new capital." Farmers Union, 734 F.2d at 1503. In a similar context, the D.C. Circuit explained that "[i]f the Commission contemplates increasing rates for the purpose of encouraging exploration and development . . . it must see to it that the increase is in fact needed, and is no more than is needed, for the purpose. Further than this we think the Commission cannot go without additional authority from Congress." City of Detroit v Federal Power Commission, 230 F.2d 810, 817 (D.C. Cir. 1955) cert den sub nom. Panhandle Eastern Pipe Line Co. v City of Detroit, 352 US 829 (1956).

[18] Available on the ISO web site, at http://www.caiso.com/docs/09003a6080/09/47/09003a6080094796.pdf.

FERC has not done so in this case. There is no discussion in the order of the reasonably anticipated costs of new generation facilities, nor of the prices that such new facilities would need in order to be economic. At best, FERC has provided evidence that the $150 "breakpoint" in its soft cap proposal is $60 <u>above</u> what FERC determined to be current natural gas and NOx costs for a combined cycle plant. November 1 Order, slip op. at 42. Even were it imposing a hard price cap, the Order thus fails to provide substantial evidence for a price cap in excess of $90. This is not to say there may not be such evidence. If there is, however, FERC has not provided it here. FERC's failure to attempt to "calibrate" the relationship between rates and the attraction of new capital is all the more egregious here, where FERC's soft cap proposal permits bids to be submitted, and thus rates to be charged, without any limits.

VI. THE ORDER ERRONEOUSLY LIMITS REFUND LIABILITY BOTH TEMPORALLY AND QUANTITATIVELY, IN VIOLATION OF THE FPA

A. Refund Liability Should Be Imposed Retroactively

1. FERC May Order Refunds Where The Parties Are On Notice That Rates Are Not Final And Are Subject To Change

It is well-established that FERC may order refunds without violating the filed rate doctrine or the corollary rule against retroactive ratemaking, provided that buyers and sellers were on notice that the rates being charged were "provisional," and might be subject to adjustment in the future. <u>Public Utils. Comm'n v. FERC</u>, 988 F.2d 154, 164 (D.C. Cir. 1993). These limitations on FERC's authority "simply [do] not extend to cases in which buyers are on adequate notice that resolution of some specific issue may cause a later adjustment in the rate being collected at the time." <u>Id.</u> (quoting <u>Natural Gas Clearinghouse v. FERC</u>, 965 F.2d 1066, 1075 (D.C. Cir. 1992)). Importantly, to be adequate, the notice need not be an express announcement by FERC that a particular rate is provisional and subject to refund. <u>See</u> <u>Id.</u> at 164-65. It is sufficient that it is clear, on the basis of FERC's statements or the conduct of the relevant parties, that rates may be subject to change. See Id. at 164-66.

Such is the case here. FERC's orders relating to electrical restructuring in California are replete with qualifications that indicate that these decisions were provisional, and which warn that the structure and dynamics of the markets and their resulting rates were subject to adjustment or revision. For example, FERC's November 1996 order authorizing the establishment of the California PX and ISO was expressly deemed "conditional" and "preliminary." Pacific Gas & Elec. Co., et al., 77 FERC ¶ 61,204 at 61,793 (1996). FERC's subsequent October 30, 1997 order authorizing the ISO and PX to commence operations, and authorizing market-based rates, also was expressly termed "interim" and "conditional." Pacific Gas & Elec. Co., et al., 81 FERC ¶ 61,122 at 61435 (1997). That order clearly put all concerned on notice that adjustments were likely in the future, stating that FERC would "closely monitor the operations of the ISO and PX, require further studies and reporting by the ISO and PX, and [would] make modifications to [its] authorization in the future if circumstances warrant." Id. Similarly, FERC's December 17, 1997 Order Authorizing Transfer of Operational Control of Jurisdictional Facilities (from PG&E, SCE, and SDG&E to the ISO), imposed certain conditions on the transfer, and indicating the provisional nature of the decision, expressly reserved the right to "place further conditions on the transfer for good cause shown." Pacific Gas & Elec. Co., et al., 81 FERC ¶ 62,210 at 64,473 (1997).

Subsequent orders continued to reflect the interim and provisional nature of the market structure, and the possibility, if not likelihood, of future adjustments. For example, on March 30, 1998, the day before the ISO began operation, FERC accepted for filing certain changes in the ISO's tariff, which were the subject of several substantive protests. California Indep. Sys. Oper. Corp., 82 FERC ¶ 61,327 (1998). Significantly, not only did FERC accept the tariff subject to refund, but also – in an entirely open-ended fashion – ruled that it was subject to "further Commission orders." Id. at 62,294-95. Similarly, FERC's June 24, 1998 order accepting still another proposed tariff amendment for filing recognized that in light of the "rapid pace" of change in the California markets, the amendment was only a "short-term" solution to the problems it was intended to address, and required the ISO to "report on progress of the long-term solution no later than 90 days from the date of [the] order." California Indep. Sys. Oper. Corp., 83 FERC ¶ 61,309 at 62,272 (1998).

As FERC's November 1, 2000 Report makes clear, the transition to market-based rates in California has been a work in progress, and not only were the relevant parties on notice as to the provisional nature of the market's structure (and consequently the rates charged), but they have experienced continual changes as the market's design and rules have been altered in the face of the results of ongoing monitoring. See November 1 Order, slip op. at 8-9 (noting, inter alia, 30 separate amendments to the ISO's tariffs, an ordered redesign of the Ancillary Services markets which is not yet complete, and the imposition of varying price caps in those markets).

The "whole purpose" underlying the filed rate doctrine and the rule against retroactive ratemaking is to provide buyers and sellers with a degree of predictability. Electrical Dist. No. 1 v. FERC, 774 F.2d 490, 493 (D.C. Cir. 1985). Where, as here, there is no final, non-provisional, rate or market structure, there is nothing certain on which buyers and sellers can justifiably rely, and accordingly no predictability for those doctrines to protect. They simply are not applicable. See Natural Gas Clearinghouse, 965 F.2d at 1075. In this circumstance, nothing prevents FERC from ordering refunds for what it now recognizes have been unjust and unreasonable charges for wholesale energy over the past three years. See Id.

2. FERC Has Authority To Authorize Refunds When Rates Charged Exceed The Filed Rate[19]

Independent of FERC's authority to order refunds when the relevant parties are on notice of the provisional nature of FERC's earlier orders, FERC also may order refunds for rates charged in excess of a filed rate. See Louisiana Pub. Serv. Comm'n v. FERC, 174 F.3d 218, 224 & n.6 (D.C. Cir. 1999); Towns of Concord, Norwood, and Wellesley v. FERC, 955 F.2d 67, 73 (D.C. Cir. 1992).

Here, the relevant rate tariffs on file indicate only that rates will be set by the market. (E.g., APS Energy Services Company's FERC Electric Rate Schedule No. 1 indicates only that "All sales . . . shall be made at the rates established by agreement between the purchaser and APSES"). Consistent with its statutory responsibilities, however, FERC may not simply accept for filing, and approve as just and reasonable, a tariff that guarantees only that sales will be made at whatever rate a market dictates. Market-based rates are just and reasonable – and therefore within FERC's power to approve – only when the market is sufficiently efficient and sufficiently free from the ability of market participants to exercise market power so that the actual prices charged in the market approximate the "true" market price (i.e., the price that would obtain in a hypothetically fully competitive and efficient market). See Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486, 1510 (D.C. Cir. 1984) (discussing relationship between "true" market price and "actual" market price); see also Louisiana Energy & Power Auth. v. FERC, 141 F.3d 364, 365 (D.C. Cir. 1998) (FERC may authorize market-based rates when there is a "competitive market"); Elizabethtown Gas Co. v. FERC, 10 F.3d 866, 870 (D.C. Cir. 1993) (same); Federal Power Comm'n v. Texaco, Inc., 417 U.S. 380, 394-97 (1974) (Commission must affirmatively

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[19] In this section and the preceding section assume, arguendo, that tariffs on file indicating that energy wholesalers will charge market rates constitute filed rates to which the filed rate doctrine applies. We emphasize that this assumption is made for the purpose of argument only. The CPUC questions whether in fact there are any rates on file in connection with California's wholesale energy market that constitute "filed rates" to which the filed rate doctrine applies.

assure that rates it approves are just and reasonable, and cannot assume that the market will produce such rates). Consistent with the requirement that rates be just and reasonable, the filed rate cannot be simply whatever the market will bear.

As a consequence of this requirement, the market-based rate tariffs on file here must be read as implicitly specifying a rate that approximates the "true" market rate that would result from an efficient market in which the participants are unable to exercise significant market power. Actual charges that exceed this "true" rate because of market inefficiencies or exercises of market power, therefore, would exceed the filed rate and be subject to refunds. Here, FERC has concluded that structure of, and rules pertaining to, California's wholesale electric market are "seriously flawed," that the market is not operating efficiently, that there have been opportunities for exercises of market power, and that these flaws have resulted in unjust and unreasonable rates. In this circumstance, FERC can and should deem those rates to have been charged in excess of the approved tariffs, and order refunds of that excess.

B. The Order Improperly Limits Refund Liability to "Opportunity Costs"

To the extent that the November 1, Order does establish refund liability, i.e., for the period commencing October 2, 2000, that liability is improperly limited. The November 1, Order states that "should we find it necessary to order refunds, we will limit refund liability to no lower than the seller's marginal costs or legitimate and verifiable opportunity costs." November 1 Order, slip op. at 44. This appears to mean that, for instance, where a seller has actual short-run marginal costs of $75/MWh, and FERC determines that a bid of $500/MWh is unreasonable, but FERC determines that the seller had an "opportunity cost" of $400/MWh due to prices or expectations of prices in out of state markets, the seller's refund liability will be limited to $100. Or, as may be more likely, the seller will claim an opportunity cost of $500, and FERC will make no finding of unreasonableness at all.

By limiting refund liability to amounts in excess of opportunity costs, FERC has effectively declared individual sellers' time-differentiated or regionally-differentiated opportunity costs to be equivalent to just and reasonable rates for the purposes of the FPA. This concept is, to say the least, highly questionable, particularly in a context where FERC has found rates to be unjust and unreasonable, where FERC has found supply to be tight, and where FERC has acknowledged that tight supply conditions confer market power on suppliers. The limitation of refund liability to opportunity costs should be reconsidered. At a minimum, clarification is necessary as to what FERC will consider "legitimate and verifiable opportunity costs."

If FERC means to include as "opportunity costs" a sellers' expectations of other bids in the ISO or PX markets, or expectations of other prices at nearby western trading hubs, such as Palo Verde or the California-Oregon Border ("COB"), the refund liability protection provided by the November 1, Order is meaningless. While such a meaning may well reflect sellers' existing expectations, as discussed above, the many reports on California's sequential electricity markets have established that a meaningful assessment of market power must include an analysis of all of the ISO and PX markets together. It has become increasingly clear that all western electricity markets influence one another, and that a complete analysis must look at the various western spot markets as a single market. For instance, even the November 1, Order states that the "Staff Report demonstrates that during the summer of 2000 correlations between PX prices and Western market bilateral prices were quite strong." To the extent California rates are not just and reasonable, therefore, regional prices are also unlikely to be just and reasonable.

Any analysis of PX prices that does not explain high ISO prices, but merely characterizes the high ISO prices as an opportunity cost exogenous to transactions in PX markets makes the same error. To argue that PX market prices are high because ISO market prices are high is circular reasoning. To limit refund liability for excessive PX prices on the grounds that the ISO price—or the Palo Verde price—is an "opportunity cost," rests on similarly flawed logic. This concept is particularly offensive where, as here, there is clear evidence of the exercise of market power in the ISO, and where the FERC has expressly found that prices are unjust and unreasonable. If this is what is meant in the November 1, Order, the proposed refund liability is meaningless, and violates the FPA.

The interrelated nature of various pricing jurisdictions is one of the reasons various parties have proposed a price cap applicable to all FERC-jurisdictional sellers in the WSCC region.[20] FERC has recognized that regional markets influence one another in its orders addressing the Eastern ISOs. In NSTAR Services Company, 92 FERC ¶ 61,065, slip op. at 15, FERC set the price caps for ISO New England, PJM, and the NYISO at the same levels, stating:

> Our decision to approve the bid cap at the level of $ 1,000 in the New England energy market is also influenced by our concerns about coordination with neighboring control areas during periods of mutual capacity deficiency or emergencies. Different bid caps in neighboring control areas could create supply problems. A single cap across major trading regions would limit incentives to sell into a higher price region during capacity shortages that affect several regions simultaneously. The $ 1,000 per MWh bid cap that we accept here for New England is at the same level as the cap that is currently in effect in PJM and that we are approving concurrently in an order for the New York ISO.

Accordingly, it is illogical to use regional "opportunity costs" as a proxy for determinations of reasonableness.

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[20] See e.g. Stoft, Analysis of FERC's Order Proposing Remedies for California (November 12, 2000), available at www.stoft.com.

C. The Order Provides No Guidance as to What FERC Would Accept as Sufficient Evidence for the Exercise of Market Power Sufficient to Warrant Refunds

Like the August 23, Order before it, the November 1, Order provides no guidance as to what evidence FERC will accept as sufficient to establish that market power has been exercised resulting in unjust and unreasonable rates as to which refunds are warranted. FERC should provide such guidance. The November 1, Order's refusal to order refunds suggests that a finding that market power has been exercised and that unjust and unreasonable market prices have resulted is, alone, insufficient to warrant refunds, and instead that evidence of individualized behavior by a market participant will be necessary to establish refund liability. November 1 Order, slip op. at 44. If this is FERC's policy, it is misguided, and should be reversed.

The CPUC submits that unjust and unreasonable market prices within the refund period (whatever that period is ultimately determined to be), alone, are sufficient to warrant refunds, and that FERC should not require consumers or their representatives to engage in individualized witch hunts for "bad" market behavior. Under the market clearing price structure in effect prior to the November 1, Order, when prices were unjust and unreasonable, all sellers received that price. Thus all sellers are equally subject to refund. It matters less whether a particular seller was instrumental in setting the unjust and unreasonable price than that the seller received the unjust and unreasonable price. Moreover, due to the bidding rules in the ISO and PX, it will often be difficult to identify with precision which entity actually set the clearing price.

However, should FERC determine that individualized cases must be made against individual sellers in order to obtain refunds, for both the period before and after a final order in this docket, FERC should clearly spell out the kind evidence it will expect to see, and ensure that such evidence becomes available in discovery in these dockets.

D. FERC Must Articulate A Process For Bringing Forward Refund Claims

The November 1, Order is ambiguous as to the status of this proceeding after November 22, 2000, and thus ambiguous as to both the availability of and the process for bringing forward refund claims. On the one hand, the November 1, Order, states, at page 14 and footnote 31, that "the data analyzed in the Staff Report and the limited time available were not sufficient to make determinations regarding the exercise of market power by individual sellers," and that "the Commission will evaluate any information it receives [regarding market power abuse] as part of its review of these markets." On the other hand, the November 1, Order limits presentation of "all arguments and supporting evidence that [parties] wish to present" in these dockets to submissions due November 22, 2000, and provides that replies will not be entertained. Id., slip op. at 50.

It is thus not clear whether and how claims for refunds may be brought to FERC after November 22, particularly claims pertaining to the period prior to November 22, 2000. FERC should, of course, entertain all such claims and all evidence bearing on them. Pursuant to the August 23 Order, it would appear that Docket No. EL00-98-000 is the appropriate forum for such claims. FERC should clarify that its order limiting presentation of evidence and arguments in this docket to submissions due on November 22, 2000, does not apply to claims for refunds, and should establish procedures for bringing forward refund claims.

VII. PROCEDURES SHOULD BE ESTABLISHED TO AWARD REFUNDS

FERC should utilize its authority to award refunds to provide refunds for the periods both before and after October 2, 2000. The CPUC's preliminary calculations demonstrate that for the period between June and September, in the PX alone, actual costs exceeded reasonable costs by more than $4 billion. See Exhibit PUC-6. See also MSC, An Analysis of the June 2000 Price

Spikes in the California ISO's Energy and Ancillary Services Markets (September 6, 2000)[21] (calculating that 64.6%—two-thirds!—of $3.1 billion in market costs in June alone were above and beyond conservatively estimated competitive market costs).

Since all suppliers profited from the market power-inflated market clearing price, refunds should be awarded on a pro rata basis based on sales volume through the PX. Hearings will be necessary both to confirm the quantity of refunds due and the allocation of refunds.

FERC should promptly set the issue of refunds for hearing.

VIII. THE ORDER FAILS TO SUFFICIENTLY RECOGNIZE THE NECESSARY ROLE OF STATE GOVERNMENT IN CRAFTING LONG TERM SOLUTIONS

A. California Has an Appropriate Role in Determining the Governance of the ISO and PX

The CPUC agrees with FERC that the ISO and PX boards should be replaced with independent boards. However, the ISO and the PX were created pursuant to California statutes. The structure of the ISO Governing Board was modified just a year ago pursuant to an agreement between the State of California and FERC. Yet the November 1, Order asserts unbridled federal authority to modify the governance structures of these California corporations. In this regard, as discussed further in the comments filed on this date by the California Electricity Oversight Board (EOB"), the November 1, Order oversteps its proper bounds. Moreover, the CPUC has serious reservations about the proposed process for appointing a new board, which provides no assurance that the ISO will operate in the best interests of California and it consumers and businesses.

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[21] Available on the ISO web site at http://www.caiso.com/docs/09003a6080/07/dc/09003a608007dc78.pdf

B. FERC Must Recognize the State's Role in Utility Procurement Decisions, and the Implications of Eliminating the Buy/Sell Requirement on State Ratemaking

FERC proposes to terminate the "buy/sell" requirement effective December 31, 2000. Under the buy/sell requirement, PG&E, Edison, and SDG&E ("the IOUs") are required to sell all of their generation into and buy all of their requirements from the ISO and PX, whether in their spot or forward markets. FERC's decision appears to be premised largely on the conclusion that the buy/sell results in "an over reliance on a spot market in a circumstance of inadequate supply." FERC states that under its proposal:

> the IOUs may elect to be their own Scheduling Coordinator rather than maintaining the current structure where the PX is the Scheduling Coordinator for the three IOUs. Without this buy/sell restriction on wholesale trade, the IOUs are free to pursue a portfolio of long- and short-term resources and access whatever wholesale markets are suited to meeting the needs of their retail customers (including bilateral markets, the PX, and others such as Automated Power Exchange, Inc.) or by providing power from their own resources to serve their own load and self provide the necessary ancillary services.

The CPUC response is outlined here and set out more fully below. First, FERC should acknowledge that both the CPUC and FERC have separately imposed "buy" requirements on the IOUs, and clarify that the proposed elimination of the "buy" requirement set out in the November 1, Order eliminates only the FERC requirement. In other words, there are two layers to the "buy" requirement. One remains in place until the CPUC removes it. Second, the CPUC agrees that necessary flexibility for forward and bilateral contracting should be provided to the IOUs, in a manner that takes into account the implications for state ratemaking that such a change would entail, and ensures that retail ratepayers are not subject to speculation. Third, elimination of the sell requirement also has impacts on state ratemaking that cannot be accommodated immediately. Finally, elimination of the must-sell requirement could have market power implications.

1. FERC's Elimination of its "Buy" Requirement Does Not Eliminate the CPUC "Buy" Requirement

In the August 23, 2000 Order in these dockets, FERC correctly held that certain matters affecting the California markets "are not within the jurisdiction of the Commission [i.e., FERC]." San Diego Gas & Electric Company, 92 FERC ¶ 61,172, at 61,605. One of these factors which is not within FERC's jurisdiction is "rules under which SDG&E provides retail electric service which limit its actions as a purchaser of wholesale power (e.g., requirements that SDG&E make all purchases through a single power exchange and restrictions on SDG&E's ability to enter into wholesale supply or risk management agreements that could protect against excessive volatility in wholesale commodity prices)." Id. In the same decision, in its discussion of the fact that SDG&E had failed to utilize the forward contracting authority provided to it by the CPUC, FERC held that "the Commission has no authority over retail electricity rates nor authority to rule on the prudence of SDG&E's provision of retail electric service." Id. at 61,607. The CPUC's jurisdiction over the buy side of the buy/sell requirement derives from its authority over the prudence of an IOU's provision of retail electric service, including procurement practices incidental to such service. See Public Service Co. v. Patch, 167 F.3d 29, 35 (1st Cir. 1998).

FERC appears to have recognized the limitations on its jurisdiction in the November 1, Order as well, albeit in a somewhat more ambiguous manner. The November 1, Order observes, for instance, that "the California Commission restricts the IOUs' ability to procure forward products." November 1 Order, slip op. at 25. Similarly, in its discussion of actions that FERC would like to see others take, the November 1, Order "encourage[s] the California Commission to eliminate restrictions on the IOUs availing themselves of long term products." Id. at 49.

FERC should simply clarify that its proposal to eliminate the "buy" side of the buy/sell requirement does not eliminate the CPUC's similar requirement. Failure to do so would not only contradict FERC's prior decisions in this case and many others, but exceed its jurisdiction under the FPA.

In addition, state law may prohibit the CPUC from permitting the IOUs to transact business in exchanges other than the PX, such as the Automated Power Exchange. Public Utilities Code § 355.1, enacted earlier this year in Assembly Bill ("AB") 2866,[22] prohibits the CPUC, prior to June 1, 2001, from "authorizing electrical corporations to purchase from exchanges other than the Power Exchange."[23]

2. Elimination of the Buy/Sell Has Implications for State Ratemaking Which Must Be Considered

The elimination of the buy/sell requirement has numerous implications for state ratemaking which must be considered. The November 1, Order observes that the buy/sell requirement was originally established by the CPUC to serve several purposes of California electric restructuring. It was adopted by FERC in December 1996. See Pacific Gas & Electric Company, 77 FERC ¶ 61,265 at 62,087-62,089 (1996). Together, the buy/sell was intended to ensure a deep and liquid PX market with transparent pricing. The "sell" requirement served to mitigate IOU market power. California once assumed that a liquid PX market served to provide a transparent and reasonable wholesale price. This presumption of reasonableness displaced the need to conduct reasonableness review of the IOUs procurement decisions, practices, and results—an important consideration since all of the IOUs' load was to be satisfied through the

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[22] Stats. 2000, Ch. 127.

[23] The CPUC has interpreted this code provision to permit the IOUs to engage in bilateral transactions outside of any exchange. See Opinion Regarding Bilateral Transactions, D.00-08-023; 2000 Cal. PUC LEXIS 555.

wholesale market. The PX price is also used in a number of critical areas of state ratemaking. The PX price is used to calculate utilities' stranded costs, i.e., the extent to which their retained generation assets are above market. It is also used to calculate the Competition Transition Charge, the charge by which the utilities recover their stranded costs. The PX price is also used as the benchmark against which bills for Direct Access customers are calculated. It is used by many retail energy service providers to set their retail price offerings. See generally D.00-06-034, 2000 Cal. PUC LEXIS 505, at *68-75.

As discussed above, the CPUC is committed to providing utilities sufficient flexibility to hedge their risk, in a manner which is reasonable. However, completely eliminating the mandatory buy/sell requirement has substantial implications on state retail ratemaking and cannot be accommodated within 60 days as proposed by FERC.

3. Elimination of Sell Requirement Could Have Market Power Implications

The market power concerns which animated the must-sell requirement have not completely evaporated with the divestiture of IOU thermal generation. As the November 1, Order notes, the IOUs retain a substantial portion of California capacity, although they are net buyers in most hours. While it may be true that the IOUs still subject to the rate freeze may not have an incentive to exercise supply market power now, that fact may change once the rate freeze ends. For example, in PG&E's hydro divestiture proceeding, the CPUC has yet to establish whether PG&E or a purchaser of PG&E's hydropower network would be in the position to exercise significant market power after the termination of the buy/sell requirement at the end of the transition period. In any case, the must-sell provision should not be terminated without adequate consideration of an alternative hydro market power mitigation mechanism.

C. The Proposals To Require Reporting To FERC by the ISO, PX And Suppliers Of Bids And Transactions Above $150, And Market Monitoring Reports, Should Be Modified To Require Reporting To State Government As Well

The CPUC supports FERC's proposals in the November 1, Order to require reporting of bids and transactions above $150, and transmission of market monitoring reports to FERC. Although the value of this requirement as a price mitigation measure is highly speculative, the required data could prove very useful. FERC should modify these proposals to provide that the same information be provided simultaneously to state regulatory and oversight agencies with relevant statutory authority. In California, this would be the CPUC and the EOB.

FERC has proposed as part of its price mitigation scheme that the ISO and PX be required to report to FERC on a monthly basis all bids in excess of $150, including the name of the seller, the price and amount of MWs covered by the offer, the hour(s) covered by the offer, the bid sufficiency in the market (i.e., the total amount bid compared to the amount needed), and the load at the time of the offer. FERC has also proposed that the ISO also be required to report unit availability data for all Participating Generators. November 1 Order, slip op. at 40.

In addition, FERC has proposed to condition the market-based rate authority of public utility sellers by requiring each seller to file on a weekly basis each transaction in the ISO and PX spot markets that exceeds $150, to include the name of the seller, the price and amount of MWs covered by the transaction, the hour(s) covered by the transaction and the incremental generation cost. November 1 Order, slip op. at 41. The November 1, Order states that the filing may also identify legitimate opportunity costs that are known and verifiable that the seller considered in developing its bid, i.e., prior to the transaction. FERC wants this data to "monitor prices on a more current basis, in order to detect potential exercises of market power or otherwise non-competitive market prices and to adjust transaction prices, if necessary, to establish just and reasonable rates." Id. Finally, FERC has proposed that all ISO and PX market reports be filed by the ISO and PX with FERC at the same time that they are released to their respective boards. This requirement would allow FERC more timely information on market behavior. November 1 Order, slip op. at 33.

These are a salutory proposals. Their value as price mitigation measures, however, are highly speculative. This is especially true if the proposal to limit refund liability to the amount in excess of opportunity costs is made final. As established above, the refund liability measure is meaningless if opportunity costs are defined to include expected bids in other venues in the interconnected western spot markets. Although FERC apparently sees the reporting requirements as a means of persuading suppliers not to bid too far in excess of their costs, they are not likely to have much effect without real refund exposure.

The required reports should provide valuable market monitoring information, however, of use to both state and federal regulators. FERC should modify the proposal to require that each of the required reports be provided simultaneously to state regulatory and oversight agencies. As this summer's events have demonstrated, effective market monitoring, and preservation of customers' rights, can be accomplished only with adequate access to relevant data. As events have also demonstrated, market participants have used every tool at their disposal to deprive state government of access to such data. See e.g. Motion Of The Public Utilities Commission Of The State Of California For Adoption Of Protective Order, To Compel Production Of Documents, And To Shorten Time To Answer, filed November 5, 2000, in these dockets. The CPUC is prepared to agree to a reasonable protective order concerning such information.

While bidding information and related data is sensitive and should be protected from competitors, that information must be provided to state government. The CPUC requires the information to monitor the efficiency of the markets, and the reasonableness of prices they produce, and to take steps to ensure appropriate and effective remedial action when prices are unjust and unreasonable.

IX. THE PROPOSAL TO CHARGE AN UNDERSCHEDULING PENALTY TO LOADS IS UNJUST AND UNREASONABLE

The CPUC agrees with FERC's conclusion that underscheduling must be reduced, but disagrees with the remedy proposed in the November 1, Order. The proposal to solve the underscheduling problem on the backs of load is unjust and unreasonable, arbitrary and capricious, not the product of reasoned decisionmaking, and not based on substantial evidence. Some form of underscheduling penalty may well be appropriate. But such a penalty must be crafted to provide proper incentives to suppliers, as well as to loads, to schedule ahead of real time, and to offer forward contracts at reasonable prices. In addition, it must not discourage the diversity of California's generation by penalizing resources such as wind generators which may underschedule out of necessity.

The November 1, Order observes that "there is a chronic pattern of underscheduling load and generation in the PX's Day Ahead and Day-of market." November 1 Order, slip op. at 26) . As the ISO has previously demonstrated, real time volumes have approached 30% of the ISO control area load this summer, which poses serious reliability issues for the ISO. Underscheduling on this scale also has significant impacts on real time prices, and results in large Out-of-Market ("OOM") purchases by the ISO, generally at or near the ISO price cap. As FERC notes, both underscheduling and OOM costs are dramatically higher this year compared to last. Id.

FERC errs, however, when it defines underscheduling to occur "when an entity schedules significantly less energy than its expected actual consumption." Id. at 26, n. 53. This definition implies that loads are the cause of underscheduling. Such an implication is erroneous on several counts. First, it conflicts with the FERC's description in the same paragraph of a pattern of "underscheduling load and generation." It also conflicts with FERC's further discussion of the issue, at page 46 of the November 1, Order. There, FERC correctly observes that it is sellers who have "stay[ed] out of the PX's auction" in favor of waiting for the ISO to "make the needed purchases on an out-of-market basis at the last minute." Id. at 46. Most importantly, the implication that underscheduling is caused by loads is contradicted by the facts.[24]

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[24] The CPUC's August 12, 2000, comments in this docket (EL00-95-000) discussed underscheduling as follows:

> Buyers thus bid in a conditional demand curve to the PX, indicating that they would be willing to purchase their entire forecast load in the PX, but only at prices at or below the ISO price cap. At the same time, sellers have routinely bid only a portion of their supply into the PX at prices below the ISO cap, choosing instead to seek higher real time, Replacement Reserve, and/or out-of-market prices.
>
> This phenomenon has been characterized either as underscheduling by demand to protect itself from high PX prices, or withholding by generators. In either case, the result is that on high demand days, large quantities of forecast demand are not scheduled in the PX markets. This causes serious operational and reliability problems for the ISO, and also caused the ISO to attempt to make up the difference in scheduled and forecast demand by arranging, well before the hour, for power deliveries from out of state control areas. The ISO has been heavily criticized by generators for making the out-of-control-area purchases.
>
> In response to the operational and reliability problems, and the criticism from generators, the ISO increased its purchase of Replacement Reserve. The ISO then used the energy from the Replacement Reserve capacity to partially make up the difference between forecast and scheduled load. In addition, in an effort to incent load to schedule in the PX forward markets, the ISO began to allocate the costs of purchased Replacement Reserve to buyers which had underscheduled. Therefore, to the extent that demand underscheduled in the PX forward market, it had to pay for both Replacement Reserve and real time energy, regardless of whether enough supply was offered in the forward markets to meet load. Buyers can not avoid these charges because suppliers have failed or refused to offer supply in the forward markets in excess of approximately 30,000 MW, even on high demand days when forecast loads are in excess of 40,000 MW.
>
> The change in ISO Replacement Reserve policy never solved the problem of over-reliance on the ISO's real-time energy market. It merely provided an additional incentive for suppliers to withhold generation capacity from the PX markets. This is because suppliers could potentially receive a capped payment for providing Replacement Reserve in addition to a capped payment for providing the associated imbalance energy. That is, suppliers could receive a $750 capacity payment for Replacement Reserve, and a second $750 energy payment when the ISO dispatched the energy associated with the reserved capacity. In addition, the ISO's policy change increased the likelihood that a particular supplier would be selected to provide both the Replacement Reserve capacity and the energy, thus providing suppliers to bid very high prices for these products. Only after this June's very high Replacement Reserve costs (e.g., $120 million for the week of June 12-16), did the ISO decide to establish a lower price cap of $100 for Replacement Reserves. The purpose this time was to reduce the incentive of suppliers to underschedule in the PX market and instead sell to the ISO markets. Note that during the June period load scheduled nearly its entire needs in the PX market, only to find that there was inadequate supply bid in the market at any price.
>
> As long as there is a price cap differential between the PX and ISO markets, there will continue to be an incentive for either load or supply to underschedule in the PX markets. The ISO will therefore continue to seek purchase and price capping policies for its markets in an attempt to compensate for this price cap differential.

In its revised report entitled "Price Movements in California power Exchange Markets, Analysis of Price Activity: May-September 2000" ("Revised PX Report") issued November 1, 2000, the PX has demonstrated unequivocably that the cause of underscheduling in the PX is that less supply has been offered in the PX at any price this summer in comparison to prior years. See Revised PX Report at 47-53. The PX has shown that 8,000 to 13,500 MW less were offered into the PX market on high-demand days in 2000 than in 1999. On August 25, 1999, over 38,000 of supply were offered in the PX Day Ahead market for an afternoon hour on a hot summer day, with load for the hour forecast by the ISO to be 40,625MW. In contrast, on May 23, 2000, only about 28,000 MW were offered in the PX, at any price. Revised PX Report, Figure 21. Similar results obtained in June and July. See Revised PX Report, Figures 22-23. It was generally impossible to procure more than approximately 29,000 MW in the PX this past summer.

Moreover, although power purchasers have, to some extent, sought shelter in the ISO's capped market, the Revised PX Report clearly demonstrates that buyers purchased as much load as possible in the PX markets. Demand curves changed drastically in 2000 as compared to 1999. Buyers in the PX offered higher prices at every load level, in an apparent effort to solicit more supply into the PX, but to no avail. In fact, buyers' attempts in 2000 to avoid underscheduling resulted only in greatly increased costs, with minimal increases in PX supply. Had demand simply submitted bids to the PX in 2000 similar to the manner that demand bid in 1999, hundreds of millions of dollars would have been saved, and little extra underscheduling would have been caused. In a single hour on June 28, only 3,000 MW was bid into the PX by suppliers at a price of less than $750/MWh. In that hour, approximately 28,000 MW cleared at a price of $750, for a cost of $21,000,000. In that hour, only 29,000 MW were offered. No more supply was available in the PX at any price. If demand had been bid in similarly to demand bids in 1999, approximately 27,000 MW would have cleared at a price of approximately $250, for a cost of $6,750,000. Revised PX Report at 48-49 and figure 21. Demand thus paid a very heavy cost—over $14,000,000 in this single hour—in its efforts to avoid underscheduling. But demand could not avoid underscheduling, because the supply simply was not there, at any price. It is thus inequitable to charge an underscheduling penalty solely to demand. Any such remedy must provide the proper incentives to both supply and demand to transact ahead of real time, for instance, by charging the penalty to both suppliers and load.

Moreover, if the underscheduling penalty is charged only to load, it will increase pressure on forward and bilateral prices. These prices are, of course, uncapped. The proposal further tilts the supply and demand relationship further out of balance. Demand for forward products will increase. Loads will rationally pay up to $99 above the expected spot price to avoid the underscheduling penalty. The expected spot price will already be inflated by this summer's high prices and the removal of the "hard" price cap. This is a recipe for continued unjust and unreasonable prices and effectively punishes the victims of high wholesale prices.

Finally, the proposal to disburse penalty revenues to buyers who accurately scheduled load shifts wealth to load serving entities who are self sufficient in generation. This is the case because it is, as demonstrated above, impossible to meet forecast load in the PX markets. Adequate supply is simply no longer offered in the PX. While, under FERC's proposal, the utilities would have the opportunity to supplement PX purchases with bilateral forward contracts, FERC has failed to take any action to ensure the availability of reasonable forward prices. Thus, only load serving entities which are self-sufficient in generation will be able to meet load without seeking the shelter of the ISO's soft-capped market. There is no rationale basis upon which such entities should receive the windfall of underscheduling penalty revenues.

X. THE DECISION TO LIMIT SUBMISSION OF EVIDENCE TO NOVEMBER 22 AND TO HOLD A PAPER HEARING RATHER THAN A TRIAL TYPE HEARING IS ERRONEOUS

FERC's November 1, 2000 Order requires comments (with attached exhibits and affidavits) to be filed by November 22, 2000 and states that reply comments "will not be entertained." November 1 Order, slip op. at 48. The FERC further states that it will issue a "final order" by the end of the year, but that other procedures may be ordered, if necessary.

The CPUC respectfully submits that additional procedures are necessary. Whereas the CPUC agrees with FERC that remedies are necessary in a FERC order by the end of the year, there are still issues which need to be addressed subsequent to the FERC's issuance of such an order. For example, as FERC acknowledged in its November 1, 2000 order: "the Staff Report notes that there is evidence suggesting that sellers had the potential to exercise market power (where market power is defined as prices above short-run marginal cost) this summer; however, the data analyzed in the Staff Report and the limited time available were not sufficient to make determinations regarding the exercise of market power by individual sellers." Id. at. 13-14. FERC also quotes the Staff Report as stating that "[f]urther study of high-priced bidding by individual firms or periods when individual generators were not running would be needed…" and the FERC stated that it would evaluate any information it receives. Id. at p. 14 n. 31.

In view of the above, FERC has found that it cannot resolve certain issues based upon the current state of the record. However, the CPUC has been stymied in its efforts to gather evidence in this regard, and has therefore filed herein on November 6, 2000 a motion to compel production against certain generators and marketers in order to receive documents which they have thus far refused to provide to the CPUC. Until the CPUC receives these documents, the CPUC will be unable to fully address the issues herein.

Moreover, the CPUC has not completed its analysis of the data that it has recently received, and has not had the opportunity to examine the data utilized for the FERC Staff Report. As discussed above, the CPUC's preliminary assessment of the data yields quite different conclusions than those of FERC Staff, suggesting that FERC staff has seriously overestimated the degree to which increased costs and tight supply explain this year's prices, and underestimated the extent to which market power has been exercised.   Additional procedures are necessary both for FERC Staff to complete their investigation, and for parties to examine the data used by FERC staff and attempt to resolve the varying results obtained from the data analyzed to date.

Finally, because FERC will not entertain replies, the CPUC will not have an opportunity to respond to the claims of certain parties, who will first present their position and any evidence against refunds and/or other remedies on November 22, 2000. Even if FERC utilizes a paper hearing, due process requires an opportunity to criticize the evidence submitted by others. Exxon Co, U.S.A. v. FERC, 182 F.3d 39, 47 (D.C. Cir. 1999); Louisiana Ass'n of Indep. Producers & Royalty Owners v. FERC, 958 F.2d 1101, 1113-14 (D.C. Cir. 1992).

Until the evidence is presented on November 22, 2000 and the CPUC's motion to compel is granted, such that additional evidence can be presented, FERC cannot determine whether disputes concerning material facts can be resolved without an evidentiary hearing. FERC "bears a weighty burden in justifying a denial of an evidentiary hearing…" Sierra Ass'n for Environment v. FERC, 744 F.2d 661, 665 (9th Cir. 1984); General Motors Corp. v. FERC, 656 F.2d 791, 798 (D.C. Cir. 1981). Moreover, while FERC has proposed and may impose certain remedies by the end of the year, this will not fulfill FERC's obligation to resolve disputes of fact with an evidentiary hearing. Sea-Land Service, Inc. v. U.S., 683 F.2d 491, 501 (D.C. Cir. 1982). Finally, additional procedures are also necessary to pursue refund claims, for the periods both before and after October 2, 2000.

In view of the above, the CPUC respectfully submits that FERC issue an order by the end of the year with the interim remedies proposed by the CPUC, that the FERC grant the CPUC's November 6, 2000 motion for a protective order and to compel production of documents, and that the FERC provide for additional procedures in this proceeding so that the CPUC and others may provide supplemental evidence and pursue refund claims.

XI. CONCLUSION

FERC should modify the November 1, Order and grant rehearing as requested herein.

Respectfully submitted,

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November 21, 2000

XII. SEPARATE STATEMENT OF COMMISSIONERS DUQUE, NEEPER and BILAS

We concur with the efforts of the California Commission's central pleading seeking to provide redress to California customers for the high prices that resulted this summer from dysfunctional wholesale electric markets. We further applaud FERC's proposal to adopt price mitigation measures to ensure that next summer will not see a repeat of this summer's experience.

We find much to support in FERC's Market Order, and are filing this statement to insure that FERC has access to our full thinking concerning the technical aspects of the wholesale market, which are not the principal focus of the Commission's filing.

<u>The Underlying Cause of the Problems – Supply Shortfalls</u>

FERC's diagnosis is that the underlying problem is a demand for electricity that outstrips not only California's ability to supply electricity, but the ability of the entire Western Region as well. As the FERC Report notes on p. 27, "In circumstances like these, prices are expected to rise – and indeed they must rise to induce the investment in new capacity that is needed to serve customers adequately." This result can occur in California as well, as long as the market is allowed to function properly and without unnecessary constraints. We must recognize, however, that deregulation may bring fluctuating prices, but it also brings choice and innovation.

California's electric market, however, has a series of unnecessary restraints and novel practices that make electricity buyers particularly vulnerable to supply shortfalls or strategic actions by energy marketers. FERC's report identifies many of these and orders corrective actions. For others, however, more action is needed to ensure that restrictions imposed by states – particularly California – do not undermine the functioning of interstate wholesale power markets. Unnecessary constraints include:

a) the requirement to buy all power through the PX;

b) the novel use of a single price auction,
c) current caps on ISO and PX prices;
d) regulatory limitations on wholesale contracting,
e) the requirement that the ISO bear final responsibility for the supply of power, which makes it especially vulnerable to the underscheduling of load and resources,
f) barriers to retail competition, including limitations on interconnection,
g) retail pricing restrictions that limit a customer's ability to respond to price signals and the development of demand response programs, and
h) regulatory uncertainty and delay affecting every aspect of the electric industry, from production to retail sale.

If California constraints on the market are minimized to those necessary to protect clear public interests[25], then, in conjunction with FERC regional mitigation measures, the generation market will function much like energy markets in the rest of the country and long-term stability will result in reasonable market prices.

FERC's Proposal to Eliminate the Requirement to Sell Into and Buy From the PX Serves the Public Interest

The FERC Report calls for ending the California Commission's requirement that Sempra, SCE and PG&E sell all of their generation into and purchase all of their energy from the PX. We wholeheartedly agree. One of us has argued against the PX monopoly since before the 1995 Preferred Policy Decision was issued. A second viewed this as a transition mechanism that no longer serves as useful purpose. Three commissioners have voted to end the PX monopoly, only to find themselves quickly reversed by a state statute that limits the CPUC's ability to reduce or

[25] For example, there are clear public interests in retaining appropriate environmental, local land-use, and safety regulations. Reliability regulations are also necessary, but must be reconciled with the need for just and reasonable prices.

eliminate the monopoly position of a dysfunctional exchange.[26] Although we are bound to follow California statutes, there can be no doubt that we believe that FERC's proposed policy best serves the public interest. The PX market has had limited forward products and high prices. We applaud FERC for making the termination of the PX monopoly an immediate reform measure, because ending this monopoly will ensure the responsiveness of markets to customer's needs.

The question of jurisdictional authority over the mandatory PX buy/sell requirement for utilities must be determined by the FERC. We have always maintained that these are state jurisdictional matters. The requirement first surfaced in the California Commission's Preferred Policy Decision, D.95-12-063. The California statute codifying the restructuring regime, stemming from AB 1890 of 1996, did not specifically speak to the requirement. FERC in its acceptance of the utility implementation filings did approve a regime with the mandatory buy/sell requirement. However, the California Commission and the California State Legislature have modified the requirement, most notably in D.00-08-023 allowing utility bilateral contracts outside of the PX. We are mindful, however, that many accounting calculations for California's deregulated markets are tied to PX prices. Therefore, California needs time to untie its restructuring efforts from the PX.

While the state maintains jurisdiction, we are willing to cede to FERC temporary jurisdiction over this matter. As a practical matter, we are concerned that the California Commission has not, and may not in a timely manner, take up this critical issue. There is no current docket where this is a pending issue. Given the importance of moving forward with an

[26] See Decision 00-06-034, allowing for the development of alternative qualified exchanges. This aspect of the decision was reversed by legislation . However, no California law mandates a PX monopoly on either the buy or sell side for the utilities. Thus, the California PUC has voted to allow utilities to enter into certain bilateral contracts outside of the PX. See D.00-08-023.

improved market structure as soon as possible, we support either a FERC decision to eliminate and phase out the mandatory buy/sell requirement, or a FERC order with strong incentives and a definite timetable for the State of California to do so.

FERC Should Move to Abolish the Single Price Auction for Power Exchanges in the West

We note, with approval, Commissioner Hébert's suggestion to eliminate the single price auction used to set prices in the PX. Although the Commission opted for the single price auction in order to provide price transparency and to encourage abundant suppliers to bid their marginal costs, Commissioner Hébert is correct to point out that the use of this auction protocol is no longer appropriate. In fact, we note that major markets in the United States, such as the market for Treasury Securities, commonly utilize a system where the bidders receive their bid price, not the market clearing price. Prudence alone would dictate that we consider this bidding protocol for electricity if a mandated auction mechanism is retained.

However, we applaud the FERC's exhortation to the California Commission to allow the expanded use of bilateral contracts. We believe such bilateral contracts are appropriate in lieu of mandated PX auctions Neither the single price auction nor the pay-as-bid mechanism provides a way for buyers of power to exercise their market strength to negotiate on behalf of consumers. This is a critical element missing in the current market.[27] As the FERC has noted, forward contracts and hedging mechanisms can provide stability in the market. Further, bilateral contracts must be part of a mechanism toward just and reasonable rates as these contracts help equalize the bargaining position of buyers to that of sellers by turning buyers into active participants and negotiators instead of simple price-takers.

[27] With the exception of direct access providers and marketers, which make up a small part of the market. In particular, in the residential sector, utilities retain at least 98% of the customers.

The result of the single price auction in thin markets – such as the California energy market – is to enable all market participants on the seller side to receive the benefits from the strategic actions of a few suppliers. It is our conclusion that in the current market, the single price rules guarantee that all benefits of competition accrue to suppliers. Only a move to a full bilateral contracting in which buyers and sellers can negotiate freely with relatively equal bargaining power will restore balance and benefits to consumers. If the FERC and/or the California Commission allow or mandate significantly increased use of bilateral contracts by utilities, then the pay-as-bid auction mechanism will work. As with the above-mentioned Treasury market, pay-as-bid can work to keep prices reasonable, but only when the buyer has alternatives.

<u>A FERC Price Cap Is An Appropriate Transition Measure</u>

While we prefer market pricing over the long-run, we recognize the need for a transition period to allow the market structure to improve and various market factors to be put into place. Therefore, we appreciate the need for short-term measures that seek to mitigate the current problems in the marketplace. As the FERC Report points out, there is a danger that price caps or other measures will discourage the very investment needed to reach equilibrium over time. However, some type of cap is clearly necessary during the period in which sellers may be able to exercise market power, in order to ensure that rates will not be unjust and unreasonable. It is clear that to be effective, it must be WSCC region wide. We will defer to others to propose a specific workable regional short-term cap mechanism.

<u>The California Commission Should Remove Limitations on Bilateral Contracting and Forward Products to Stimulate New Supply and Reduce Price Volatility</u>

California restrictions on bilateral contracts and forward markets have led to an over reliance on the PX. The over reliance of California wholesale markets on the PX has ensured that its limitations have a dominant effect on the price that Californians pay. FERC notes that it is time to change and we agree.

Thus, FERC's order has not only prescribed medicine for California's sick wholesale electric markets; it has also diagnosed certain regulations of the California Commission as part of the problem. FERC prescribes medicine for us – FERC recommends that the California Commission eliminate restrictions on the participation of SDG&E, SCE, and PG&E in forward markets for electric power, including bilateral contracts. Although FERC notes that we have recently made progress allowing more utility contracting, FERC's staff notes, with disfavor, the California Commission's "after-the-fact prudence reviews." FERC staff concludes that these reviews "dampen a purchaser's incentive to buy forward."

There is clearly more that the California Commission can do. The California Commission's August decision, D.00-08-023, gave PG&E and SCE limited power to sign bilateral contracts for power. This decision proposed that the California Commission, via resolutions prepared by the Energy Division, give these utilities clear guidance on the reasonableness of potential contracts to minimize the regulatory uncertainty. To date, however, we have not provided the guidance that PG&E and SCE have sought, and no contracts have been pre-approved. Moreover, we have not taken the other steps that FERC recommends and have not removed remaining restrictions on the amounts of power that SCE and PG&E can forward purchase. It is clearly unreasonable to require these utilities to purchase so much power in volatile spot markets.

Even more action is needed to remediate our current treatment of SDG&E. Our September 21 decision, D.00-09-075, left in place after-the-fact prudence reviews for SDG&E.[28]

In light of the new facts brought to light by FERC's analysis, we believe the California Commission should consider modifying its decisions to adopt FERC's recommendation. It is clear that FERC and its staff, although reluctant to intrude on our regulatory authority, consider post-hoc reasonableness reviews a source of California's problem – not a protection against high rates. We expect that the California Commission will consider such a motion to modify this decision – either our own motion or a motion of one of the parties – very soon.

We appreciate the sensitivity of FERC to the jurisdictional discretion of the California Commission. Nevertheless, it is our conclusion that California laws and regulations may prove so restrictive and so incapable of change that state action will destabilize the federally regulated wholesale market. Indeed, it is our belief that state restrictions on bilateral contracting and the purchasing of forward products led to an unstable situation where too much power passed through short term or spot markets, increased their volatility, minimized the power of buyers, and contributed to this summer's price spikes and high power costs. In addition, the inability of IOUs to sign bilateral contracts made it difficult for generators to secure the financing needed to bring new supply to market. For these reasons, we hope that FERC will continue to monitor the restrictions that California places on IOUs to ensure that they do not undermine the federal interest in a properly functioning marketplace.

We would be open to exploration by FERC of another alternative to granting per se reasonableness to UDC forward bilateral contracts. It is clear that rates in California are not just and reasonable. Forward markets are a function of spot markets. Therefore, today's forward markets are reflective of unjust and unreasonable spot markets. That is why one of us has favored

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[28] This was done based on an interpretation of AB 265 which seemed to require prudence reviews. Another

prudence reviews of long-term forwards. We have a price bubble which must be pricked to get forward markets back on track. California and FERC should work together on a method to make just and reasonable spot markets become the benchmark for forward markets. Right now the "forwards" insurance premium is too high. Looking to the UK and Australia vesting contracts, a possible solution could be 12 to 18 month cost-based bilateral forward contracts for a set amount of capacity, approved by FERC in consultation with the California Commission. These would provide a transitional device so that the forward markets will develop in this interim period based on a rational benchmark. After the transitional period, bilaterals of any duration are likely to reflect just and reasonable spot market prices. This is preferable to giving reasonableness review protection to up to 5-year contracts that reflect today's dysfunctional market prices and will be passed on to residential ratepayers.

<u>FERC's Proposal to Sanction the Underscheduling of Load and Resources is Good Policy</u>

The FERC order seeks to limit "the ISO to only the functions needed to reliably operate the transmission system, i.e., provide a balancing service rather than running an energy market." (p. 36.) We recognize the ISO should retain a role in facilitating imbalance markets. However, it is clear to us that not only is too much power going through short-term markets, but too much power is bought at the last minute by the ISO. This places an unwarranted burden on the ISO, whose prime directive is to ensure system reliability. Clearly the ISO has taken this as a directive to procure power at any price and regardless of whether megawatt laundering has occurred.

The ISO was intended as an "air traffic controller" for the state's energy paths. This is a necessary role that the utilities and other transmission owners have performed well over the years, and that the ISO is well suited to continue to perform. The ISO is not, however, well suited to

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interpretation of that bill may be possible.

perform the pricing or purchasing function – the market (in all of its manifestations) is. In particular, the ISO does not have a cost-minimization objective, as the buyers and consumers do. The ISO has paid and will continue to pay whatever it feels is necessary (even with price caps) to ensure reliability. When power is underscheduled, the ISO must substitute its judgment for that of the market, and the ISO's judgment is based on a single criterion – reliability – without either the knowledge or expertise to determine what other factors the market may take into consideration.

Although there is no simple way to change the objective of the ISO, FERC has proposed an excellent method for limiting its function to that originally intended. FERC's proposal, as modified in our central pleading, to impose sanctions on those who underschedule load and resources[29], will restore the balance needed to ensure that the ISO's necessary commitment to reliability does not harm the pocketbooks of Californians.

Interconnection Procedures

The FERC Report directs the ISO to file generation interconnection procedures on a specified timetable. This seems a useful activity to promote ease of entry of needed new generation in the state.

Demand Response Programs Must Include Price Response Programs

The FERC Report points out that "the difficulty with current demand response in California is that it is driven by administrative directive, not market prices." (p.48) The point is well taken. It is possible, though exceedingly difficult administratively and often imprecisely applied, to use government, utility or ISO fiat to decrease demand for reliability or other purposes. Elaborate mechanisms can be set up to require selected customers to take specified

[29] We agree that there may be unique circumstances related to wind power.

actions when deemed appropriate. Such mechanisms may have the desired impact from a central planning perspective.

However, a much simpler method, both administratively and from an end-result perspective, is to allow customers to use market price information to make their own choices[30]. And there is no doubt that customers will make good choices if given appropriate information. There is evidence that San Diego customers conserved energy this summer simply because they knew from the media that prices were increasing. Clearly, the expanded use of meters and delivery of price information to consumers on a real-time basis are necessary components of a fully functional market. There are a variety of programs that come under the headings of "energy efficiency" and "metering" that empower customers to make informed choices based on price information. These programs require no central decisions about who needs to reduce (or increase in other cases) usage, how to change their usage patterns, or what the proper level of incentives should be. The market provides the information and the incentives for them. The bottom line is that absent a customer's ability to respond to price signals, the average electricity prices will be higher than without price responsiveness. Those choosing to avoid high marginal prices will not only lower the average costs for themselves, but also for the entire market. This is better than a centrally planned solution.

We strongly support FERC's suggestion to forgo administratively determined demand reduction strategies (that inevitably overpay or underpay, or work too well or not well enough) for customer empowerment vehicles. Demand itself is not necessarily inelastic, or as inelastic as it appears; it is the current customer ability to respond to demand that is insufficient to reveal the

[30] We applaud the Legislature's decision in AB 265 to require large customers, which have TOU meters, to pay market rates. We hope that if SCE and PG&E rate freezes are extended by the Legislature, they will continue to follow this approach.

actual elasticity. Innovative products have been developed to permit customer-demand responsiveness. We must facilitate their use, even under rate stabilization plans.

Regulatory Uncertainty

The simple fact is markets do not like uncertainty. The Florida Presidential vote recount reflects this and so do California electricity markets. A course must be set and adhered to on a reliable timetable. For this reason, we believe the 24-month transition period set by the FERC is reasonable and provides certainty to market participants. Leaving it open-ended would not. A date certain is not irreversible- FERC or participants can always seek to extend it, if in 2 years we have not found our way out of the quagmire of dysfunctional markets. For similar reasons, we believe FERC's decisions to reject the extension of the ISO price cap and to terminate the $250 price cap after December 31, 2000 are warranted.

Additionally, if regulatory certainty requires temporarily ceding certain jurisdictional disputes to the FERC for an interim period, we are willing to do so. Playing politics with markets is to no consumer advantage.

Governance of the PX and ISO

The FERC order calls for the elimination of the stakeholder boards. We concur. However, stakeholders should have advisory input into how the ISO runs, both on a technical level to ensure reliability and commonality of operational understandings, and on a policy level to ensure all views are understood and considered. With the limitations on the role of the ISO in markets discussed above, the balance between reliability and policy issues shifts to the former.

Stakeholders should not be the decision-makers simply because of their vested interests. Even a well-designed set of checks and balances leaves the potential for self-serving outcomes ("deals") or lack of outcomes due to failure to get issues on the table. The ISO board should be more independent, as its name suggests.

As for the PX, if the FERC recommendation to eliminate the mandatory PX buy requirement is given effect, the PX will become a voluntary organization for both buyers and sellers. In this sense, we are less concerned about the make-up of the PX board, as market participants will have options if they do not like the direction taken by the organization. The FERC Report makes a similar point. However, we recognize that the PX is likely to remain an important part of the California market for some time to come until this Commission untangles its restructuring efforts from PX prices.[31] Therefore, we support the FERC's proposal for an independent PX board.[32]

Refunds May Not Be the Only Answer

While we are not convinced the FERC will be able to grant retroactive refunds to California consumers, if FERC finds a way to do so, we support it. The people of California deserve relief and a percentage sharing among all generators is appropriate in the absence of finding specific exercises of market power. It is clear market power has been exercised and abused collectively. Just because FERC cannot identify individual miscreants does not mean mischief has not occurred.

[31] Many aspects of California's transition to competitive markets key off PX prices, such as CTC calculations, QF prices, and pending decisions on PX credits for non-UDC generators.

[32] We take no position on the question of who should appoint independent board members for the PX and ISO.

Unfortunately, the California comments do not address FERC's request to address "other equitable remedies" besides refunds. Creative minds at the state and federal levels should be able to devise some. We urge FERC and parties to continue to try to do so.

Conclusion

The FERC Report states, "Prices based on traditional cost of service are incompatible with fostering a competitive marketplace." (p. 56) Prices based on traditional cost of service are also incompatible with other important goals such as customer empowerment, minimization of regulatory errors, and innovation. The Report also says, "We believe it would be a mistake to revert to the kind of rate regulation that contributed to the decline in investment that clouds California's energy future today." (p. 59) The FERC does not want to move backwards. Neither do we. But,we agree interim reasonable and just rate stability is necessary to get to the benefits of competitive markets.

As California Governor Gray Davis discussed at the November 14, 2000 FERC meeting in this docket in San Diego, it is California's policy to move to a responsible competitive marketplace for generation. We believe market structure changes under FERC jurisdiction -- temporary regional price caps, elimination of the PX buy/sell requirement, minimization of the ISO's market functions, PX and ISO board structure changes and possibly interim cost based forward contracts -- are needed to allow the competitive market to work properly. We will work to bring the needed changes to California's regulatory structure, in such areas as price responsiveness, bilateral contracts, and retail competition.

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon all known parties in this proceeding by mailing by first-class a copy properly addressed to each party.

Dated at San Francisco, California, this 21st day of November, 2000.

/s/ SEAN GALLAGHER

SEAN GALLAGHER