UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents.	)	Docket No. EL00-95-012
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)	Docket No. EL00-98-000
California Independent System Operator Corporation	)	Docket No. RT01-85-000
Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council	)	Docket No. EL01-68-000

MOTION FOR CLARIFICATION AND
REQUEST FOR REHEARING OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

The California Independent System Operator Corporation ("ISO")[1] respectfully submits this Motion for Clarification and Request for Rehearing of the Commission's Order Establishing Prospective Mitigation and Monitoring Plan for the California Wholesale Electric Markets and Establishing an Investigation of Public Utility Rates in Wholesale Western Energy Markets issued April 26, 2001

[1] Capitalized terms not otherwise defined herein are used in the sense given in the Master Definitions Supplement, Appendix A to the ISO Tariff.

in the above-captioned dockets, 95 FERC ¶ 61,115 ("April 26 Order"), pursuant to section 313(a) of the Federal Power Act, 16 U.S.C. § 825l(a) (1994), and sections 212 and 713 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.212 and 385.713 (2000).

I. INTRODUCTION AND SUMMARY OF POSITION

Market-based rates are not an entitlement. Given the right structural conditions and regulatory framework, market-based rates in conjunction with competitive markets for electric supply can be an appropriate means to the end mandated by the Federal Power Act: the establishment of charges for wholesale power that are just and reasonable. However, market mechanisms may lawfully supplant traditional cost-of-service regulation only where it is possible to conclude with confidence that the market will yield just and reasonable rates, and that opportunities for consumer exploitation have been precluded. In particular, where market-based rate authority has been granted, constant vigilance must be maintained and, as market conditions change, the Commission must be prepared to reexamine, recondition, or revoke market-based authority as necessary to achieve the uncompromised result of just and reasonable rates. In the words of Commissioner Massey, "[o]ur passion for markets must be tempered with common sense and respect for our statutory obligation at the FERC to insure just and reasonable prices."[2]

There can be no dispute that the mitigation now in place in the California wholesale markets has utterly failed to stem the rampant exercise of market

[2] Transcript of the April 10, 2001 conference in Boise, Idaho at 20.

power, resulting in unconscionable prices, already driving Pacific Gas & Electric Company ("PG&E") into bankruptcy and Southern California Edison Company ("SoCal Edison") to its brink, spared only by the unprecedented intervention of the State. There simply no longer is time for academic debate or for half-hearted attempts at mitigation. There is no competitive market in California, and the Commission's fundamental error is its refusal to accept this essential fact.

California is doing all that is within its power to do. The State has stepped in as a purchaser, substantial rate increases have been approved, demand-side programs have and are being put in place, and new plant expansion is being accelerated. It is now time for the Commission too to take hard actions. The prevention of economic chaos likely extending far beyond California and the very welfare of the consumers who, after all, are the Commission's core responsibility, require no less. Indeed, viewed even from the vantage point of an advocate for deregulation, it is imperative that the unconscionable prices associated with the market power that has been exercised,[3] and that will be allowed to continue under the April 26 Order, be absolutely foreclosed. States that once were committed to a competitive model already are pulling back because of the California experience. Unless the Commission makes unmistakable its intolerance for leaving in place even the slightest potential for the exercise of

[3] By "market power" the ISO means the ability of a seller to influence market outcomes, especially the market price for a sustained period. *See* Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities – Part 1, November 1, 2000, at 5-17 ("November 1 Staff Report"). Market power can be exercised through either economic or physical withholding. Economic withholding occurs when a supplier bids in excess of its variable costs in order to raise the market clearing price. In physical withholding, the supplier does not provide all its resources to the market, in order to increase the Market Clearing Price for the remaining supply. *Id.* at 5-21.

significant market power, movement toward competition can only be seriously and irreparably retarded.

Unfortunately, the April 26 Order falls far short of what minimally is required. That the Commission has proposed some constructive action is not disputed; that it will be insufficient to preclude the continued exercise of market power cannot be doubted, for many reasons, including the following:

- The uncontroverted evidence is that market power has and is being exercised in all hours, not just those of reserve deficiency; yet the proposed mitigation would apply only during times of emergency;

- The uncontroverted evidence is that market power is being exercised across all markets; yet the proposed mitigation would apply only to the ISO's Imbalance Energy market; and

- With regard to "megawatt laundering," the proposal is only that the issue be studied and possibly addressed at an unspecified later date; yet it should be obvious that only action taken *now* can possibly hope to mitigate further problems during the summer.

Given the facts already known, and given the urgency of the situation, the Commission has but two options:

(1) it can return immediately to traditional cost-of-service ratemaking principles (or a simplified approach designed to emulate cost-of-service principles such as the suggestion made by Commissioner Massey and recently endorsed by the Governors of California, Oregon,

and Washington of using generator-specific variable costs plus a reasonable capacity adder in the range of $25/MWh);[4] or

(2) it can condition the continued exercise of market-based rate authority on a comprehensive (region-wide) effective mitigation approach, such as recommended by the ISO in its Market Stabilization Plan filed with the Commission on April 6, 2001 and in its May 7, 2001 comments on the Western Systems Coordinating Council ("WSCC")-wide Section 206 investigation.[5]

The April 26 Order, inexplicably, adopts neither approach. It is inconceivable that the modest mitigation proposed would succeed at constraining prices to competitive market levels; such a mitigation approach cannot, therefore, support the continued authorization of market-based rates. The principal deficiencies include:

- application of price mitigation only when the level of available Operating Reserves falls below 7.5 percent, and the ISO is required to declare a System Emergency - Stage 1.[6] The record is replete

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4 *See* March 9, 2001, letter to the Chairman and the Commissioners from Governors Davis, Kitzhaber, and Locke.

5 To permit implementation of an appropriate and comprehensive mitigation proposal, the ISO, in the immediate future, will be filing the necessary tariff modifications.

6 The Commission defines reserve deficiency as anytime reserves fall below 7.5 percent. April 26 Order, 95 FERC at 61,361. The WSCC requires that the ISO (and all other transmission providers in the WSCC) maintain Spinning Reserves and Non-Spinning Reserves equal to the greater of: (1)The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency, or (2)The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation. WSCC Rate Schedule No. 1, First Revised Sheet No. 27. In the case of the ISO it is the latter 5 percent and 7 percent reserve responsibility which is applicable.

with evidence demonstrating that suppliers are able to exercise market power during all hours and under all system conditions, *and that they do so consistently*. Limiting price mitigation only to emergency conditions unlawfully exposes consumers in the West, not just California, to excessive prices that will not be constrained by effective competition.

- application of price mitigation only to the Imbalance Energy market. Evidence and logic confirms that resources will be shifted to unmitigated markets requiring that mitigation be applied comprehensively if massive loop-holes are to be avoided. The April 26 Order would leave completely unprotected from market power abuse Ancillary Service procurement necessary to satisfy minimal reliability requirements, and Congestion Management, a market that is critical to efficient grid operation.
- use of a "proxy price," the cornerstone of the mitigation scheme, that would be based on unrepresentative emissions[7] and gas prices.
- the failure to take any constructive steps to eliminate or even to minimize the pernicious effects of "megawatt laundering."
- an ambiguous requirement for the submission of Demand bids by public utilities purchasing in the ISO's Imbalance Energy market. If it is meant to require the submission of "reservation bids" for all Energy

[7] *See* the Motion of the California Air Resources Board for Expedited Consideration and for Limited Rehearing and Clarification or, in the Alternative, for Partial Stay and a Technical Conference filed in this proceeding. A copy of this pleading is provided as Attachment A.

requirements, those bids would serve to distort the Market Clearing Price; the Demand proposal is unworkable, arbitrary, and unlawful.

- limitation of the availability of price mitigation to a one year period, without recognizing that it is the recipients of market-based rate authority who must first meet the burden of establishing that mitigation no longer is required before it may be removed. To now suggest that mitigation can be eliminated contemporaneous with the onset of a period of peak Demand (the summer 2002 season) would be a blatant prejudgment of circumstances that the Commission cannot know and has no basis to anticipate.[8]
- conditioning the limited price mitigation that it authorized on the submission of a further regional transmission organization ("RTO") filing by the ISO and the California investor-owned utilities. Leaving aside, for the moment, the efficaciousness of an RTO filing and of the Commission's authority to require it, what the Commission absolutely cannot do is to condition its willingness to discharge its statutory responsibilities on action to be taken by others.

The ISO does not make this filing out of hostility to market-based rates or to the competitive market paradigm. To the contrary, the ISO shares the view that a truly competitive electric market can and should increase consumer welfare by producing both efficiencies and innovation not as likely to be

[8] That new capacity is being added is not disputed. But to now assume a level of supply sufficiency adequate to support a competitive market is reckless, particularly in view of the age of the existing inventory of California generation.

stimulated under the traditional regulated structure. But if the ultimate goal is stimulation of a competitive electric sector, the Commission must recognize that public receptivity to that fundamental change will be influenced by how quickly, decisively, and effectively the Commission responds to perform its legal obligation to protect consumers when conditions inconsistent with workable competition arise and threaten public well-being. If, in the face of overwhelming evidence of market power abuse, the Commission sits silently by or responds ineffectively out of an unfounded faith that the market itself will resolve the current crisis, the evolution to a competitive electric market will surely be stalled, if not ultimately abandoned.[9]

On a broader social basis, therefore, the need for immediate relief in this case is compelling. In the face of the extreme prejudice being imposed daily on California consumers and on the State's economy, and in order to provide the needed stability and relief to enable policy makers to plan an orderly transition to a workably competitive market environment, the Commission must immediately enact far more effective mitigation measures than those provided by the April 26 Order.

II. SPECIFICATIONS OF ERROR

The ISO respectfully submits that the April 26 Order errs in the following respects:

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[9] As explained by Ms. Marylyn Showalter, Chairwoman of the Washington Utilities and Transportation Commission, "lack of active supervision of prices in the west coast market is rapidly eroding political confidence that a competitive market is even the right policy objective." Transcript of the April 10, 2001 conference in Boise, Idaho at 33. Recently, the State of Nevada enacted AB 369 repealing most of its restructuring law. The measure prevents utilities from selling off their generating plants and stops implementation of retail access.

1. In limiting the availability of price mitigation to the Imbalance Energy market and to times of reserve deficiency. Mitigation must apply to all markets (including Ancillary Services and Congestion Management) and to all hours.

2. In failing to adopt the price mitigation proposal advanced by the ISO in its filings of March 22, 2001,[10] April 6, 2001,[11] and May 7, 2001,[12] in Docket Nos. EL00-95, *et al*. or, failing that, to revert to cost-based rates.

3. In basing the proxy price calculation on unrepresentative emissions and natural gas indices.

4. In failing to expressly state that out-of-state Generators must provide justification for the their bids above the clearing price.

5. In inflating wholesale prices by permitting any and all gas-fired generators, including non-dispatchable units such as combustion turbines ("CTs") to establish the Market Clearing Price.

6. In imposing a Demand response requirement that exceeds the Commission's statutory authority, is inconsistent with the

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[10] Comments of the California Independent System Operator Corporation On Staff's Recommendation On Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market, Docket No. EL00-95-012 (Mar. 22, 2001) ("March 22 Comments").

[11] The ISO provided a detailed description of the Market Stabilization Plan ("MSP") on April 6, 2001 in Docket No. EL00-95-012 in response to the Commission's letter order of March 30, 2001.

[12] Comments of the California Independent System Operator Corporation On the Commissions Proposed West-Wide 206 Investigation and Price Mitigation in Spot Markets Throughout the WSCC in Docket No. EL00-95-012, *et al*. (May 7, 2001) ("May 7 Comments").

Commission's prior orders on creditworthiness, and is inconsistent with existing State and ISO Demand reduction programs.

7. In failing now to put in place measures to eliminate the potential for megawatt laundering and in failing to apply price mitigation to the interdependent region-wide market.

8. In continuing the underscheduling penalty.

9. In linking the availability of price mitigation to an RTO filing.

10. In limiting the duration of price mitigation to a one-year period, effectively and impermissibly shifting the burden of proof, and exposing consumers to unlawful market power abuse precisely at the onset of a period when the potential for abuse is greatest.

III. ARGUMENT

A. The Federal Power Act Mandates the Establishment Of Rates That Are Just And Reasonable; Market-Based Rates May Be Authorized Only Where the Commission Can Be Confident That the Resulting Charges Will Satisfy That Statutory Imperative

1. The Statutory Standard

Presumably, there is no dispute about the applicable statutory standard: rates for wholesale power must be "just and reasonable." 16 U.S.C. §§ 824d, 824e. *See Federal Power Com'n v. Hope Natural Gas. Co.*, 320 U.S. 591, 611 (1944); *Atlantic Refining Co. v. Public Utility Com'n of the State of New York,* 360 U.S. 378 (1959).[13] To be sure, the Commission enjoys considerable flexibility in selecting the means to that end, *Hope*, 320 U.S. at 602, but whatever path the Commission elects, the journey must come to rest with the establishment of rates

[13] Although these seminal decisions concerned the Natural Gas Act, the Federal Power Act is interpreted in parallel to the Natural Gas Act. *See, e.g., Federal Power Com'n v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1956); *Federal Power Com'n v. Conway*, 426 U.S. 271, 281 (1976); *Public Service Company of New Mexico*, 25 FERC ¶ 61,469, at 62,060 n.160 (1983).

that are within the zone of what is just and reasonable, *see, e.g., Alabama Electric Cooperative v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982). While rates cannot be so low as to be confiscatory, *see Federal Power Com'n v. Texaco, Inc.*, 417 U.S. 380, 391-92 (1974), the primary purpose of the standard is to protect consumers against excessive rates, *see Hope,* 320 U.S. at 610-612; *Pennsylvania Water & Power Co. v. Federal Power Com'n*, 343 U.S. 414, 418 (1952); *Sierra Pacific*, 350 U.S. at 355; *Atlantic Refining*, 360 U.S. at 388. Rates that fall outside that zone of reasonableness are *illegal* and, confronted with such rates the Commission is obliged, *sua sponte* if necessary, to take corrective action.

To understand what is meant by rates that are just and reasonable, it is necessary to bear in mind why Federal Power Act rate regulation was provided in the first place. It was precisely to address the rampant abuses that characterized wholesale power markets before 1935 and the inability of states to police wholesale power prices that the Commission's predecessor was authorized to regulate wholesale electricity prices. *See Gulf States Utilities Co. v. Federal Power Com'n*, 411 U.S. 747, 758 (1973); *see also Hope*, 320 U.S. at 610. It was because of the universal recognition that rates that were the product of the exercise of market power were injurious to consumers and to the economy – it was because such rates were neither just nor reasonable. *Id.* Rates that have embedded within them the ill-gotten fruits of market power – *i.e.*, monopoly rents – are *per se* outside of the permissible zone.

Federal regulation, therefore, was intended to emulate the results that could be expected to pertain in a free, workably competitive marketplace – namely, rates that cover the producer's costs (including a fair return of and on investment, commensurate with the underlying risk of providing the service) while providing consumers with essential services at the lowest possible cost. *See,* *e.g., Hope*, 320 U.S. at 603; *Alabama Electric Cooperative*, 684 F.2d at 27. It was necessary for regulation to step in because the market had failed; and as a result, prices were inflated with the prejudice of abusive market practices.

Therefore, now to adopt as the regulatory model the sanctioning of market prices that are the product of the abusive exercise of market power – that are infused with monopoly rents – would be a complete abdication of the very purpose of Commission regulation. It would amount to nothing less than a sanctioning of illegality.

2. <u>The Courts and the Commission Have Recognized Limitations That Govern the Authorization of Market-Based Rates</u>

Among the rate methodologies that the Commission may allow is the use of market-based rates. *See Elizabethtown Gas Company v. FERC*, 10 F.3d 866, 875 (D.C. Cir. 1993). What the Commission *cannot* do, however, is abdicate to the market its responsibility to set just and reasonable rates in the face of indications that the market structure that is in place cannot be relied upon to fulfill that statutory requirement. *See Texaco,* 417 U.S. at 397. The seminal judicial discussion of the interplay between just and reasonable and market-based rates is that of the Court of Appeals for the District of Columbia Circuit in *Farmers Union Cent. Exchange v. FERC*, 734 F.2d 1486 (1984). There, the Commission had presumed that if it simply established ceiling prices, albeit at very high levels, "market forces could be relied upon to keep prices at reasonable levels throughout the oil pipeline industry." *Id.* at 1510. The Court's response was very much to the point:

> Without empirical proof that it would, this regulatory scheme, however, runs counter to the basic assumption of statutory regulation, that "Congress rejected the identity between the 'true' and the 'actual' market price." *FPC v. Texaco*, 417 U.S. at 399, 94 S.Ct. At 2327. In fact, FERC's "'regulation' by such novel

> 'standards' is worse than an exemption simpliciter. Such an approach retains the false illusion that a government agency is keeping watch over rates, pursuant to the statute's mandate, when it is in fact doing no such thing." *Texaco v. FPC*, 474 F.2d at 422.

Farmers Union, 734 F. 2d at 1510. *See also*, *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1005 (D.C. Cir., 1990) (where the Commission's acceptance of a settlement was overturned in the absence of "substantial evidence upon the basis of which the Commission could conclude that market forces will keep Texas Eastern's prices in reasonable check").[14] It is of more than passing interest that in *Farmers Union*, the Commission had found the oil pipeline industry "competitive" as evidenced by "the significant decline in the price of pipeline transportation from 1931-1969 . . ." (*Farmers Union*, 734 F. 2d at 1494) – a pricing pattern that stands in marked contrast to the trend in wholesale electric prices in California over the past three years. It is also significant that in justifying a somewhat lenient construction of "just and reasonable" the Commission, as the Court acknowledged, drew a distinction between the rigor required in the regulation of electric utilities as contrasted with oil pipelines:

> [c]onsidering numerous differences in the reasons for the establishment of a regulatory scheme over "public utilities," such as electric companies, as opposed to "transportation companies," such as oil pipelines, FERC determined that:
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> > the authors of the Hepburn Act's oil pipeline provisions did not use the words "just and reasonable" in the sense in which public utility lawyers have used them since the 1940's.
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> > We think that what was meant was not "public utility reasonableness," but ordinary commercial

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[14] *See*, *also*, *Air Transport Assoc. v. Dept. of Transportation*, 119 F.3d 38 (D.C. Cir., 1997) where the statute required the Secretary to establish guidelines pursuant to which airports receiving federal assistance would establish "reasonable" fees. The Court struck down the Secretary's deference to market forces, where there was insufficient evidence of adequate competitive forces to keep fees in check, even though the Secretary had found that the public airports at issue had no incentive to maximize profits.

> "reasonableness." To be specific, we discern no intent to limit these carriers' rates to barebones cost. What we perceive is an effort to restrain gross overreaching and unconscionable gouging.

> Thus, on the basis of this historical survey, FERC interpreted the statutory mandate that oil pipeline rates be "just and reasonable" to require only the most lighthanded regulation, with no necessary connection between revenue recoveries and the cost of service.

Id. at 1493 (citations omitted). If anything, a more stringent application of the "just and reasonable" standard is applicable under the Federal Power Act than under the Interstate Commerce Act's oil pipeline rate regulation regime that was at issue in *Farmers Union*.[15]

The discussion in *Elizabethtown Gas Co.*, 10 F.3d at 871, sets forth the demanding prerequisites for market-based rates. There, the Court sustained the Commission because the record evidence confirmed that:

> Transco will not be able to raise its price above the competitive level without losing substantial business to rival sellers. [citation omitted] Such market discipline provides strong reason to believe that Transco will be able to charge only a price that is "just and reasonable" within the meaning of § 4 of the NGA [Natural Gas Act].

The Commission's holdings are to the same effect. In its very first, quite tentative, "experimental" flirtation with market-based rates – one that included an upper bound on what could be charged – the Commission observed:

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[15] In its brief to the Court of Appeals in *Farmers Union*, one oil pipeline owner (whose affiliate now exercises market rate authority for sales from California-based electric generating units) urged that a more lenient construction is appropriate in the case of oil pipeline rates than would be permissible for public utilities:

> The Commission, having found oil pipelines not to be public utilities, the arguments for cost-based rates, such as those commonly ordered for utilities, rest on a foundation of sand. As the Supreme Court has recognized, a particularized adherence to a scalded "cost of services" approach has proved impractical in the past.

Brief of Williams Pipeline Company as Intervenor-Respondent at 22-23.

> In considering the proposed upper bound, we frankly acknowledge that there is a real tension between the needs of the experiment, on the one hand, and our duty to protect consumers from overcharges on the other. An ideal experiment would have *no* upper bound on price. Thus, if our hypothesis that competitive market forces will restrain prices were wrong, we would be able to observe utilities with market power exercising that power by consistently charging prices above cost. While such results would be very valuable from an experimental point of view, they would be damaging, at least in the short-run, to the consumers we are bound to protect. The courts have given us great freedom to move away from cost-based regulation where there is an important policy objective to be served by doing so, but that freedom is not unlimited.

Public Service Company of New Mexico, 25 FERC ¶ 61,469, 62,053 (1983) (citation omitted). Notwithstanding that the rate experiment was to be of limited duration (no more than two years), and that rates would be constrained within an established zone of reasonableness (a condition which the Commission characterized as "an absolutely necessary ingredient in the experiment, and is neither so wide as to likely cause substantial injury to consumers, nor so narrow as to prevent market power from manifesting itself, should it exist," *Id*. at 62,060), the Commission imposed a two-prong monitoring regime, one part of which "will focus on market performance through the use of price-marginal cost margins and price dispersion measures." *Id*. at 62,042. As will be discussed presently, this is the very methodology upon which the analyses submitted by the ISO's Department of Market Analysis ("DMA") are based – analyses that indicate the rampant exercise of market power.

Thereafter, the Commission authorized market-based rates where the seller lacked or had adequately mitigated market power and the rate was subject to a cap based on the seller's costs, s*ee, e.g., Pacific Gas and Electric Co.*, 42 FERC ¶ 61,406 (1988); *Pacific Gas and Electric Co.* 45 FERC ¶ 61,061, or on the buyer's avoided cost, *see, e.g., Ocean State Power*, 44 FERC ¶ 61,261 (1988); *Citizens Power and Light Corp.*, 48 FERC ¶ 61,210 (1989); *Chicago*

Energy Exchange of Chicago, 51 FERC ¶ 61,054 (1990). To establish the absence of market power, it was held that a seller would have to establish that it is unable "to increase prices by restricting supply or by denying the customer access to alternative sellers." *Ocean State Power*, 44 FERC at 61,979.

In *Public Service Company of Indiana, Inc.*, 51 FERC ¶ 61,367 (1990), where once again permissible market rates were capped (by the buyers' avoided cost), the Commission nonetheless stressed its obligation continually to monitor market performance, emphasizing that it "*will not hesitate to reimpose cost-of-service regulation* if competition among generating utilities fails to improve overall efficiency as expected or *if [the company] gains market power*." *Id.* at 62,226 (emphasis added).

Finally, in *Entergy Services, Inc.,* 58 FERC ¶ 61,234 (1992), *rev'd on other grounds sub nom., Cajun Elec. Power Co-op, Inc. v. FERC*, 28 F.3d 173 (D.C. Cir. 1994), in granting market-based rate authority, the Commission not only noted that non-traditional rates must be within the "zone of reasonableness," but also that, under *Farmers Union*, a departure from cost-based rates required that "the regulatory scheme act[ ] as monitor to determine whether competition will drive prices to a zone of reasonableness *or to check rates if it does not*." *Id.* at 61,752 (emphasis added). To facilitate that essential market monitoring, the Commission there, as it has in every grant of market-based rate authority since, imposed on the utility the obligation to reestablish its entitlement no less often than every three years.

3. The Undisputed Record Before the Commission Is That Market Power Is Being Exercised At All Times and Under All System Conditions

a. Prior MSC Studies Demonstrate That Market Power Is Being Exercised Even When There Are No System Emergencies

Prior studies by the Market Surveillance Committee ("MSC") of the ISO's markets have established that market power was exercised in tight supply conditions over the periods prior to December 2000. These exercises of market power, however, did *not* occur only or even predominantly during System Emergency conditions.

In its October 19, 1999 Report on the Redesign of the California Real-Time Energy and Ancillary Services Markets, the MSC stated,

> We find that significant market power remains in California's wholesale energy markets during periods of high total system load, which primarily occur during the summer months.
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> * * * *
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> During these periods, price movements across hours of the day are significantly in excess of the increased costs of supplying power during these hours. . . . This is a direct indication of market power.[16]

The MSC found that actual costs during the summer of 1998 were approximately 20 percent above those predicted by the MSC's benchmark market analysis, an analysis designed to measure deviations from prices that would be associated with a market that is workably competitive. *Id.* at 8.

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[16] *Report on the Redesign of the California Real-Time Energy and Ancillary Services Markets*, Docket Nos. ER98-2843-000, *et al.* (Oct. 19, 1999), at 1 and 7-8.

On September 6, 2000, the MSC issued its analysis of the June 2000 Price Spikes in the California ISO Energy and Ancillary Services Markets,[17] finding that:

> [d]uring the months of May and June 2000, wholesale revenues from sales of total ISO load (less must-take energy) for all hours of the month in the California energy market were approximately 37% and 182%, respectively above monthly revenues under perfectly competitive pricing.

Id. at 2. The MSC concluded that the California electricity market:

> [i]s composed of a relatively small number of firms, some of which own a sizable fraction of the total electricity generating capacity located in the ISO Control Area. The geographic distribution of generation unit ownership can allow some owners to exercise locational market power during certain system conditions. In addition, the amount of generating capacity owned by some market participants allows them to exercise market power during high load conditions, *when there is not a physical scarcity of available generating capacity to serve this load.*

Id. at 5 (emphasis added).

These tight supply conditions, exercises of market power, and unjust and unreasonable prices occurred despite the fact that System Emergency conditions were declared in only 3 percent of the hours in May-June 2000.[18] There is no reason to believe that these conditions will not persist through 2001, given the projected scarcity of resources, and continue to contribute to exorbitant bids even outside of System Emergency conditions. Certainly, the Commission has cited no evidence on which a contrary conclusion could be based. In short, the

[17] An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets. This report and other MSC reports cited in these comments can be found on the ISO Home Page at <http://www.caiso.com/surveillance/overview/Committee.html>.

[18] See Attachment B which is a compilation of Declared Staged (System) Emergencies through May 15, 2001.

Commission makes no attempt to distinguish bidding behavior during System Emergencies from that associated with other periods. It points to no evidence to support its implicit conclusion that prices in other periods will satisfy the courts' demanding requirements for allowing unmitigated market-based wholesale rates.

b. Recent DMA Studies Demonstrate That Market Power Is Being Exercised At All Times Under All Conditions

More recent analyses clearly demonstrate that the problems of market power are more pervasive than the Commission's proposal assumes, occurring at all times and under all conditions. In an affidavit filed with the Commission in this proceeding on October 20, 2000, Dr. Eric Hildebrandt of DMA presented results of a systematic, quantitative analysis of market power and scarcity over the first two and one-half years of ISO operations. Results of this analysis showed that a significant degree of market power was exercised during the months of May to September 2000. Dr. Hildebrandt noted that:

> While a significant portion of the increase in wholesale costs above this competitive baseline have been incurred during hours of potential absolute resource scarcity, the bulk of these additional costs are attributable [to] a lack of competition, rather than scarcity. In addition, prices continued to significantly exceed competitive levels even after the ISO's real-time price cap was lowered to $250 in August.[19]

Furthermore, a DMA report submitted with the ISO's comments on the Commission's November 1, 2001 order in this proceeding[20] presented the results

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[19] Declaration of Eric Hildebrandt filed with Proposed Offer of Settlement in Docket Nos. EL00-95 *et al.* on October 20, 2000 at 5-7.

[20] *San Diego Gas & Electric Company, et al*. 93 FERC ¶ 61,121 (2000), *reh'g pending,* ("November 1 Order").

of a quantitative analysis by DMA staff of the impact of market power and other factors on market costs. As explained in this report:

> [S]ince late May of this year [2000], the combination of very tight supply and demand conditions – in conjunction with very limited ability of consumers to reduce consumption in response to high prices – has created the opportunity for the persistent exercise of market power in California's wholesale energy markets. The exercise of this market power has inflated wholesale energy costs significantly above levels that would have resulted under competitive market conditions, even after taking into account fundamental market factors driving up costs and hours of potential scarcity of supply. While some degree of market power may be tolerable from the perspective of defining a workably competitive market, the exercise of market power since late May of this year has clearly exceeded the level that may be considered consistent with a workably competitive market. Since additions of new supply are likely to merely keep pace with or even fall short of demand growth over the next two years, the exercise of significant market power can be expected to continue – if not worsen – over the next two years absent action to more effectively mitigate system-wide market power.[21]

The studies by Dr. Hildebrandt and Dr. Anjali Sheffrin attached to the ISO's March 22, 2001, Comments in this docket on Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market provide further evidence that market power is being widely exercised under all market conditions.[22] Specifically, these studies demonstrate that Market Participants can affect market prices in California by altering output or bid prices during a wide range of system conditions, not just in those hours

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[21] *See Analysis of Market Power in California's Wholesale Energy Markets*, Attachment A to the ISO's November 22 Comments on the November 1 Order in Docket Nos. EL00-95 *et al.*, at 9.

[22] The ISO incorporates by reference Dr. Hildebrandt's study, Dr. Sheffrin's study, and the responses to a March 30, 2001 letter from Mr. Daniel Larcamp, the Director of the Commission's Office of Markets, Tariffs and Rates relating to those studies.

where a deficiency in Operating Reserves requires the ISO to declare a System Emergency. In addition, these studies show that the incidence of strategic bidding behavior has increased considerably over the periods studied. Thus, rather than being confined to Stage 3 System Emergencies, or even to Stage 2 or Stage 1 System Emergencies, the problem of market power *under all system conditions* has continued to worsen.[23] The April 26 Order fails to provide any basis for disregarding these analyses or to justify the Commission's failure to take the minimum action required in light of their findings: conditioning the continued use of market based wholesale rates on effective mitigation in *all* hours.

On April 2, 2001, the ISO filed a protest of the compliance filing of Williams Energy Marketing & Trading Company ("Williams") in Docket No. ER99-1722-004. The ISO attached additional analyses from the DMA showing that Williams engaged in either physical or economic withholding during *every* hour of the May 2000 through November 2000 period, and that subsequent to the Commission's termination of the ISO's price cap authority, Williams' exercise of market power was even more pronounced, resulting in revenues from the ISO real-time market for the months of December 2000 through March 2001 that were almost twice (173 percent) its estimated operating costs. There is no

[23] Dr. Eric Hildebrandt found that 30 percent of the wholesale energy prices over the last year can be attributed to the exercise of market power and determined that, on an annualized basis, wholesale prices since January 2000 exceed the cost necessary for new investment by approximately 400 percent and would allow recovery of an investment in new supply in a period of just over one year. Dr. Sheffrin found withholding, especially economic withholding, plagued the market for most hours from May to November 2000. Of the 25,000 hourly bidding profiles studied, fewer than 2 percent displayed no clear pattern of withholding. The study provides direct evidence that many large suppliers actively have engaged in strategic bidding efforts, consistent with oligopoly pricing behavior, with a direct and substantial impact on market prices.

reason to believe, based on DMA's other analyses, that Williams' behavior was unique. Nor is there any basis for the Commission to disregard DMA's analyses without even holding a hearing or to presume, in the face of contrary evidence, that suppliers' exercise of market power will be limited to System Emergency conditions.

In the context of pipeline regulation, the Commission has stated that, "if a company can sustain an increase in its rates in the order of 10 percent or more without losing significant market share, the company is in a position to exercise market power to the detriment of the public interest." *Alternatives to Traditional Cost-of Service Ratemaking for Natural Gas Pipelines*, 74 FERC ¶ 61,076, 61,232 (1996). The evidence is clear and compelling that these conditions exist and that suppliers to California's wholesale electricity markets are in fact exercising market power during all hours and all conditions of the year.

B. <u>The Market Mitigation Approach Adopted in the April 26 Order Will Fail To Constrain Wholesale Prices To Just and Reasonable Levels</u>

It has now been at least a year since the problems endemic in the California wholesale electric market became consistently evident, and the market began exhibiting significant price distortions on a continuous basis. The learning curve for the ISO, as well as for the Commission, has been steep as the exorbitant wholesale prices have continued unabated. What should be evident to all at this juncture is the need for prompt and effective action, lest the California experiment be the poison pill for all future restructuring efforts. The ISO believes that this is a seminal moment for the Commission; a chance to right the ship.

It is with great pain that the ISO and the rest of California have watched the Commission struggle with the weighty problems placed upon its doorstep. No one was prepared for the events of this past year. Nevertheless, it is evident that the structural and market reforms prescribed in the Commission's orders have been insufficient to stem market power abuses in California's electricity markets. More recently, and of great concern, the Commission's proxy price-based refund orders have only served to signal a further retreat from common-sense-based regulation. The April 26 Order, the denouement of the Commission's passion play on market power mitigation, is further evidence of the Commission's failure to address the obvious, constant exercise of market power. Frankly, it does not and should not require detailed analysis by economists to recognize that the phenomenal transfer of wealth is the product of supplier exploitation of the current market situation. Thus, while the public outrage is understandable, what is unimaginable is the Commission's failure to impose broader mitigation measures.

The Commission has totally abdicated its responsibility to ensure just and reasonable rates. Despite championing the attributes and benefits of regional coordination and markets, the Commission has left wide open California's regional "back door" and totally failed to address the "MW laundering" issue – a problem that can only be effectively addressed through regionally-applicable price mitigation measures. The Commission's sole action in this regard was to initiate a WSCC-wide section 206 investigation into spot market transactions in the West that cannot hope to bring any measure of relief in the foreseeable future. The life blood is flowing, and a tourniquet must be applied *now* in the form of comprehensive, effective measures applied region-wide. It is high time to put down the fiddle and to extinguish the fire that is rapidly consuming California's economy.

1. <u>The Commission's Prior Remedial Orders Have Been Ineffective at Mitigating the Rampant Abuse of Market Power</u>

Past experience has shown that the Commission's failure to consider the effects of its actions on all markets or the failure to address market power concerns can and will put consumers at risk. For example, in the summer of 1998, the Commission issued a number of orders stating that Replacement Reserves did not constitute an ancillary service under the Commission's Order No. 888 and allowed Replacement Reserves to be supplied using market-based pricing. *See, e.g., AES Redondo Beach, L.L.C., et al.*, 83 FERC ¶ 61,358 (1998). The result of these orders was the first significant price spike in the ISO's markets. More recently, in April of last year, the Commission emphasized the need for comprehensive structural reform of the ISO's Congestion Management regime. *California Independent System Operator Corp*., 91 FERC ¶ 61,026 (2000). However, in so doing, the Commission denied the ISO's request to reject and mitigate bids that were the result of locational market power. The consequence of the Commission's action was to require the ISO to accept all bids up to the ISO's then-applicable purchase price cap of $750/MWh even if such bids were the result of locational market power. This decision contributed to the enormous increase in costs that occurred in the Summer of 2000.

In May 2000, wholesale Energy prices in the ISO markets experienced significant increases, hitting the then-operable price cap of $750/MWh.[24] Prices spiked again in June 2000.[25] Prices in the California Power Exchange ("PX") averaged $120/MWh in June 2000, $106/MWh in July 2000, and $166/MWh in August 2000.[26] The high prices continued through the fall and into the winter. The ISO estimates that the Energy and Ancillary Service costs from the ISO markets alone for this past December and January reached $6.15 and $5.34 billion respectively, or over $11 billion for two months.[27] This compares to estimated costs *for total ISO load* of $7.43 billion *for the entire year* of calendar 1999. On a dollar per MWh basis, costs in 1999 ranged between monthly averages of about $20 to $50 with a yearly average of $31. The comparable figures for December 2000 through February 2001 were $294, $265, and $258 respectively -- nearly ten times the prices during the previous year.

The Commission has recognized the gravity of the situation and devoted significant time and energy to investigating the causes of the high prices and in

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[24] *See* Report on California Energy Market Issues and Performance: May-June 2000 dated August 10, 2000 prepared by the ISO's DMA at 9. This report may be viewed on the ISO Home Pate at <http:www.caiso.com/docs/09003a6080/07/40/09003a6080074029.pdf>.

[25] During the June 26-30 period, PX Day Ahead prices averaged $381/MWh during peak hours and reached or exceeded $749/MWh for a seven-hour block on both June 28 and June 29. On June 28, constrained prices in the ISO's NP15 Congestion Management Zone reached a high of $1,099 for five hours. *Id.* at 11.

[26] November 1 Staff Report at 3-1.

[27] *See* Attachment C to this filing, Cost Summary Through January 29, 2001.

failed attempts to mitigate the unlawful prices.[28] Nevertheless, as the Commission itself recognizes, "[t]he problems in California's electricity power supply system continue despite the implementation of immediate measures

[28] On July 26, 2000, the Commission issued an order directing a staff fact-finding investigation of the conditions in electric bulk power markets. The Commission set a deadline of November 1, 2000 for the investigation. On August 23, 2000, the Commission issued an order in Docket Nos. EL00-95-000 and EL00-98-000 initiated proceedings under Section 206 of the Federal Power Act to Address matters affecting the wholesale electricity prices in California. *San Diego Gas & Electric Company, et al.*, 92 FERC ¶ 61,172 (2000).

On November 1, 2000, the Commission Staff issued its Staff Report stating "[t]he data also indicate some attempted exercise of market power, if the standard of bidding above marginal cost is used, and some actual market power effects, to the extent that prices, at least in June were significantly above competitive levels." November 1 Staff Report at 1-4. Also on November 1, 2000 the Commission issued an order proposing measures to remedy the problems identified in the Staff Report. *San Diego Gas & Electric Company, et al*. 93 FERC ¶ 61,121 (2000), *reh'g pending,* ("November 1 Order"). The Commission found that the "electric market structure and market rules for wholesale sales of electric energy in California are seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy . . . under certain conditions." November 1 Order, 93 FERC at 61,346-50.

On December 15, 2000, the Commission issued its Order Directing Remedies for the California Wholesale Electric Markets. *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, et al.*, 93 FERC ¶ 61,294 (2000), *reh'g pending* ("December 15 Order"). As part of the mitigation measures adopted in that order, the Commission established a $150/MWh breakpoint methodology – only sellers whose bids below $150/MWh that are accepted by the ISO would be eligible for the Market Clearing Price. *Id*. at 61,983.

On March 9, 2001, the Commission issued its Order Directing Sellers To Provide Refunds of Excess Amounts Charged for Certain Electric Energy Sales During January 2001 or, Alternately, To Provide Further Cost or Other Justification for Such Charges. *San Diego Gas & Electric, Co. et al.*, 94 FERC ¶ 61,245 (2001) ("March 9 Order"). In the March 9 Order, the Commission established "a just and reasonable 'rate screen' above which refunds will either be required or further investigation will be undertaken." *Id*. at 61,862. The Commission only applied this screen during periods when the ISO was experiencing Stage 3 System Emergencies. *Id*. at 61,862-63.

Also on March 9, 2001, the Commission Staff released its recommendations on prospective market monitoring and mitigation. Staff Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market, March 2001 ("Staff Proposal"). The proposal consisted of the following elements: (1) an enhanced role for the ISO in outage coordination, (2) imposition of mandatory selling obligations on certain suppliers, (3) adoption of real-time price mitigation for each generating unit in times of significant reserve deficiencies, (4) specification of the conditions for invoking mitigation, and (5) use of a single MCP.

designed to stabilize the California markets."[29] In fact, as explained in the preceding section, market conditions have deteriorated since the Commission established the $150 soft cap in the December 15 Order.

The California electricity market has gone from being simply "dysfunctional" to a crisis that belies any semblance of a mechanism capable of producing just and reasonable wholesale and consumer rates. As a result of the rampant exercise of market power and the flaws in the restructured California electric markets, billions of dollars of additional and excessive electricity costs have been passed on to the Utility Distribution Companies ("UDCs"), including PG&E and SoCal Edison, ultimately forcing the former into bankruptcy and the latter into a state of great financial distress. The emergency not only threatens the financial stability of California, but of its neighboring states, and of the Nation.

High prices have continued unabated. In a recent study, DMA estimated that as much as $380 million or over 38% of the real time Energy costs from non-utility sources during February 2001 represent charges that may exceed just and reasonable levels relative to the costs of suppliers.[30] When compared to prices that would be expected in a single-price auction under truly competitive market conditions, DMA estimated that as much as $347 million or about 34% of the real time Energy costs during the same period represent charges in excess of prices that would have resulted under competitive market conditions.

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[29] *Further Order on Removing Obstacles to Increased Energy Supply and Reduced Demand in the Western United States and Dismissing Petition for Rehearing*, 95 FERC ¶ 61,225, slip op at 14, n.20 (2001).

[30] *See Report on Real Time Supply Costs above Single Price Auction Threshold: February 2001,* dated April 14, 2001. A copy of this Report is provided as Attachment D to this filing.

Given the financial distress of the state's investor owned utilities ("IOUs"), the California Department of Water Resources ("CDWR") has stepped in to cover most of the "net short" position – the amount of power needed to cover the difference between what the IOUs can produce from their own facilities or by means of existing contracts and the remaining actual demands.[31]

The California Public Utilities Commission ("CPUC") has approved two sets of retail rate increases, totaling over 40%, and created financial incentives for Demand reduction.[32] Meanwhile, the suppliers of electricity have already reaped astounding profits from their participation in the California wholesale electric markets.[33]

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31 On January 18, 2001 bill SB7x became law and allowed CDWR to make purchases from any party and make such purchases available to the California ISO and others, for up to twelve (12) days and $400 million. The law became inoperative on February 2, 2001. A second bill, AB1x, became law on February 2, 2001 and allowed CDWR to contract with any person or other entity to purchase power on such terms and for such periods as CDWR may prescribe. CDWR is to issue revenue bonds to support its purchasing activities.

32 *See In re Application of Southern California Edison Co., et al.,* Decision 01-03-082, dated March 27, 2001 issued by the California Public Utilities Commission (Application Nos. 00-11-038, 00-11-056, 00-10-028), 207 P.U.R.4th 261(2001); *see also* David Lazarus, *PUC Approves Across-the-Board Power Rate Hike, But Still Eyes Tiers*, San Francisco Chronicle, March 27, 2001, provided as Attachment E to this filing.

33 AES Corporation reported a net income of $221 million for the quarter ended 12/31/00 – a 97% increase over their $112 million net income for the same quarter in 1999. Press Release, AES Corporation, AES Earns $1.46 Per Share in 2000, Up 135% Over Earlier Year (January 29, 2001). In the first quarter of 2001, AES Corporation reported revenues of $2.5 billion, a 50% increase over the first quarter of 2000. Press Release, AES Corporation, AES Reports Earnings of $.042 Per Share for the Quarter, from Recurring Operations (April 26, 2001). Reliant Energy reported adjusted earnings of $838 million for 2000, compared to $508 million for 1999. Reliant Energy's wholesale energy group specifically made $482 million in 2000, compared to $27 million in 1999. Press Release, Reliant Energy, Reliant Energy's Wholesale Energy Businesses and Electric Operations Drove Earnings Up 65% for the Year 2000 (January 26, 2001). Reliant reported adjusted earnings of $274 million for the first quarter of 2001, compared to $134 for the first quarter of 2000. Reliant Energy's wholesale energy group specifically reported an operating income of $216 million for the first quarter of 2001, compared to an operating loss of $22 million in the first quarter of 2000. Press Release, Reliant Energy, Reliant Energy Reports Strong First-Quarter Earnings (April 16, 2001). Williams reported income from continuing operations of $873.2 million for 2000, compared to $178 for 1999. Williams reported income of $259.3 million for continuing operations in the fourth quarter of 2000, compared to $66.1 million for the same period in 1999. Press Release, Williams, Williams' 2000 Results from Continuing Operations Quadruple

Quite simply, the time has come to stop the madness and abuse. As discussed in the following sections the ISO has grave concerns that the mitigation measures adopted by the Commission in the April 26 Order will not meet the challenge of constraining the runaway wholesale prices and ensuring that customers obtain the statutory protection of just and reasonable rates for this vital service.

2. The April 26 Order's Price Mitigation Will Not Result in Just and Reasonable Rates

In the April 26 Order, "the Commission adopts a market monitoring and mitigation plan for the California market to replace the $150/MWh breakpoint plan adopted in its December 15, 2000 Order." April 26 Order, 95 FERC at 61,351. The Commission's plan provides for: (1) increased authority for the ISO to coordinate and control Outages of certain Generating Units; (2) a requirement that sellers with Participating Generator Agreements as well as non-public utility

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1999. Williams reported results from continuing operations of $378.3 million for the first quarter of 2001, compared to 138.9 million for the same period in 2000. Specifically, Williams' Energy Marketing and Trading segment reported a first quarter profit of $484.5 million, compared to $77.8 million for the same period in 2000. Press Release, Williams, Williams' 1st Quarter Results From Continuing Operations More Than Double Last Year (April 26, 2001). Dynegy Inc. reported a 2000 recurring net income of $452 million, a 210% increase over their reported 1999 income of $146 million. Specifically, Dynegy Marketing and Trade reported $355 million in recurring net income -- a 252% increase over 1999's income of $101 million -- which represented 80% of the company's overall results. Press Release, Dynegy Inc., Dynegy Triples Recurring Net Income in 2000 (January 23, 2001). Dynegy Inc. reported a recurring net income of $137.5 million, a 73% increase over their first quarter 2000 income of $79.4 million. Dynegy Marketing and Trade reported $100.3 million in recurring net income – a 99% increase over the first quarter of 2000's income of $50.3 million – which represented 73% of Dynegy Inc.'s recurring net income. Press Release, Dynegy Inc., Dynegy Reports First Quarter Recurring Earnings Per Share of $0.41 (April 17, 2001). Southern Energy Inc. reported earnings for operations for 2000 of $366 million, a 36% increase over 1999's $270. Press Release, Southern Energy Inc., Southern Energy Inc. Reports a 36 Percent Increase In Earnings For 2000 (January 19, 2000). Mirant reported record first quarter 2001 earnings from continuing operations of $175 million, compared with $95 million for the first quarter of 2000. Press Release, Mirant, Mirant Reports 84% Increase for First Quarter 2001 Earnings (April 25, 2001). These press releases are provided in Attachment F to this filing.

sellers within California that utilize the ISO Controlled Grid offer all their available power in real time; (3) the establishment by public utility load serving entities of response mechanisms in which they would identify a price at which load should be curtailed during all hours; (4) the use of a single Market Clearing Price ("MCP") auction for the ISO Imbalance Energy Market; and (5) mitigation of ISO Imbalance Energy Market prices during periods in which the ISO is experiencing a reserve deficiency. *Id*. at 61,354. The April 26 Order also imposes general conditions on public utility sellers' market based rate authority designed to prevent anti-competitive bidding strategies, which may be identified through ISO monitoring.[34] *Id*. at 61,360.

Despite the further deterioration of the California wholesale electricity market, the April 26 Order in effect offers even less mitigation than it would replace, establishes improper price signals, and will not promote the certainty and stability sought by the Commission.

a. <u>Despite Further Deterioration of the Wholesale Energy Market the April 26 Order Offers Less Mitigation</u>

In the December 15 Order, the Commission applied the $150 breakpoint methodology at all times. December 15 Order, 93 FERC at 61,983. The Commission recognized that, "[b]y establishing a $150 breakpoint and not pricing

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34 The ISO supports restrictions on anti-competitive or anomalous bidding behavior. The April 26 Order cites one example of such behavior – bidding that varies over time in a manner that appears unrelated to changes in unit performance or to changes in the supply environment that would induce additional risk or other adverse shifts in the cost basis. The ISO intends to actively monitor bids in a comprehensive program to detect not only the examples cited by the Commission, but other coordinated bidding practices that appear to be directed at manipulating market prices. For example, such bidding behavior could include bidding by multiple units in a single or multiple Congestion Management Zones where, in the aggregate, such behavior deviates from that consistent with individual unit performance, risks, or costs.

every MWh at the clearing price, spot prices will no longer be magnified." *Id.* at 61,996. The Commission also committed to analyze individual bids above the breakpoint and required public utility sellers to submit on a weekly basis detailed data, including information on their marginal costs (fuel quantity, fuel costs, NOx emissions rates, NOx costs, variable operations, and maintenance expenses). *Id*. at 62,011. The Commission took this action to "give purchasers the assurance that these cost factors have contributed to the higher spot prices rather than the exercise of market power." *Id*.

The ISO objects strongly to the Commission's implementation of the December 15 Order as reflected in the March 9 Order and has sought rehearing of the Commission's action. Nevertheless, the December 15 Order at least recognized the importance of extending price mitigation to all hours. In contrast, the April 26 Order perpetuates the fundamental flaw of the March 9 Order by unduly restricting price mitigation to System Emergency conditions.[35] Such an approach is contrary to the established record in this docket – a record that shows market power abuse is widespread whether or not System Emergency conditions exist. The failure of the April 26 Order to address this salient and indisputable fact will result in continuation of the massive and unsupportable transfer of wealth that has occurred over this past year. The December 15 Order recognized "the gravity of the situation and the need to expeditiously implement remedies that will avert a recurrence of the problems in California last summer as

[35] The April 26 Order does extend mitigation to encompass Stage 1 and Stage 2 System Emergencies and not just Stage 3. Since market power can and is being exercised during all system conditions, this extension is insufficient.

well as the problems in the past few weeks." December 15 Order, 93 FERC at 61,983. The April 26 Order will not meet this objective.

b. Limitation of Refund Exposure To System Emergencies Is Unreasonable

The Commission states that its mitigation plan "seeks to achieve mitigation by emulating a competitive marketplace . . . in which each supplier has the incentive to bid competitively at its marginal costs." April 26 Order, 95 FERC at 61,354. The Commission however, restricts its price mitigation to periods of reserve deficiency, corresponding roughly to conditions during or in anticipation of which the ISO declares a System Emergency to exist.[36]

The evidence described above clearly demonstrates that suppliers are exercising market power outside of System Emergency conditions. For example, the "system price cost markup" analysis prepared by Dr. Hildebrandt, which compares Energy prices to the variable cost of the marginal unit in the market that is required in each hour to meet Demand,[37] demonstrates that 30 percent of the wholesale Energy prices over the last year can be attributed to the exercise of market power (*i.e.*, that wholesale Energy costs were about 30 percent higher than they would have been in the absence of market power). His analyses show, moreover, that prices exceed the competitive market benchmark in all hours, under a variety of system conditions. The results illustrate that market power

[36] *Id.* at 61,361.

[37] As such, this methodology represents the price that would have occurred under workably competitive conditions. It attempts to account for variations in gas prices, costs of emission credits, and even appropriate scarcity rents.

abuse is not limited to hours when a deficiency in operating reserves requires the ISO to declare a System Emergency.

DMA estimates that 31 percent of the total energy costs during non-emergency hours for the period of March 2000 to February 2001 are attributable to the exercise of market power. Though the average markup above competitive levels during non-emergency hours is lower than in emergency hours, because there are many more hours of non-emergency conditions, the cost impact of market power is much higher than in emergency hours. In fact, by these estimates, the cost impact of market power during non-emergency hours represents over 54% of the total cost impact of market power in all hours. This analysis suggests that limiting mitigation to emergency hours would address less than half the cost impact of market power. Table 1 is taken from Dr. Hildebrandt's March 2001 report, *Further Analyses of the Exercise and Cost Impacts of Market Power in California's Wholesale Energy Market*[38]

[38] This study was attached to the ISO's Comments on Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market, filed in Docket No. EL00-95-12 on March 22, 2001.

Table 1 Impact of Market Power on Wholesale Energy Costs

By System Condition (March 2000 – February 2001)

	No Alert	System Alerts Stage 1	Stage 2	Stage 3	All Hours
Hours	7,165	345	469	782	8,761
Net GWh [1]	101,937	6,448	8,134	11,600	128,118
Avg. Wholesale Price ($/MW)	$117	$339	$400	$372	$170
Avg. Competitive Price	$81	$192	$298	$256	$116
Avg. Markup	$36	$147	$101	$116	$53
Total Wholesale Cost (Millions)	$11,976	$2,185	$3,249	$4,310	$21,720
Total Competitive Cost	$8,269	$1,240	$2,426	$2,967	$14,903
Total Markup	$3,707	$945	$823	$1,343	$6,818
Total Markup as % Total Costs	31%	43%	25%	31%	31%

The fact that market power continues to be exercised outside of System Emergencies is further illustrated by the ISO's experience during April 2001. Despite the lack of Stage 3 emergencies and the fact that Stage 1 emergencies were limited to 7 percent of the total hours in April 2001, the ISO estimates that real-time energy costs averaged $370/MWh in all hours.[39] In contrast, average prices were lower in January and February despite a significantly greater number of System Emergencies. This is illustrated in Table 2 which identifies the number of days in each month in which the ISO had to declare a System Emergency and the average real time price.

[39] Since none of the System Emergencies declared in April were Stage 3 System Emergencies, there would be no refunds for that month under the "rate screen" approach to mitigation adopted in the March 9 Order, despite the fact that April saw the highest average real-time Energy prices of 2001.

Table 2

Comparison of Days of System Emergencies to Average Real Time Prices[40]

Month	Number of days in which a System Emergency (Stage 1, 2 or 3) was declared	Average Real Time Price	Loads
January 2001	23	$290/MWh	18,770 GWh
February 2001	23	$363/MWh	16,500 GWh (7.32% decrease from February 2000)
March 2001	11	$313/MWh	17,857 GWh (6% decrease from March 2000 and 6% decrease from daily averages for February)
April 2001	5	$370/MWh	17,257 GWh 5.3% decrease from April 2000 and 3.47% decrease from March 2001)

Table 2 demonstrates further that there is no correlation between System Emergency conditions and the high real time prices.

Moreover, the ISO is greatly concerned that the Commission underestimates the magnitude of Load that is exposed to the excessive spot market price. Because significant portions of the Load are neither protected by long-term arrangements nor equipped with real-time metering, high prices in the spot market will not send any “signal” to spur needed investment. Instead, they

[40] The data for this table comes from the ISO’s compilation of Declared Staged Emergencies provided as Attachment B to this filing; and the DMA Market Analysis Reports for February and March/April 2001 provided as Attachments G and H, respectively.

will merely continue the unprecedented and unjustified transfer of wealth that has occurred over the past year. [41]

First, it appears that the Commission has underestimated the amount of power that is needed to cover the IOU customer load that is not met by IOU retained generation (the IOUs' "net short" position). In its December 15 Order, the Commission anticipated that the IOUs' own Generation, including Generation under IOU contractual control, amounted to approximately 25,000 MW. December 15 Order, 93 FERC at 61,993. In reality, actual output from the IOUs' own Generation and contractual entitlements averaged approximately 15,000 MW during the super peak periods of summer 2000 and never exceeded 19,000 MW.[42]

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[41] The level of Generator outages in California has also been well in excess typical patters. This is illustrated by the following chart of data developed by the California Energy Commission.

	1999	2000	2001
Month	Average of Total Megawatts Off-Line	Average of Total Megawatts Off-Line	Average of Total Megawatts Off-Line
January	3068	2423	9940
February	5096	3243	10956
March	5740	3389	13831
April	5739	3329	14990
May	3032	4012	
June	1216	2683	
July	963	2213	
August	878	2434	
September	1012	3621	
October	1761	7633	
November	2988	10343	
December	2569	8988	

This information can be found at <http://www.energy.ca.gov/electricity/1999-2001_monthly_off_line.html>.

[42] The variance may be attributable to forced or planned outages or differences between rated capacities and actual outputs, particularly hydroelectric Generation.

Second, despite the Commission's initiatives to encourage long-term contracting and the extraordinary efforts made by CDWR to engage in forward hedging, substantial amounts of Load will be exposed to spot prices. The following table presents the ISO's forecasts of the shares of system Demand (total monthly GWh of Energy delivered to Load) that could potentially appear as real-time Imbalance Energy. These numbers were generated using the dry hydro year scenario, as that is the condition expected to occur this summer. The ISO applied the dry hydro year assumptions to three different load scenarios.

Table 3
Expected Underscheduling Based on Low Hydro Supply Scenario (GWh)[43]

Normal Load Scenario	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
ISO System Load	18,917	20,773	22,441	22,786	24,039	21,420
Real-time Net Short	4,498	4,984	4,233	4,629	5,533	5,801
Net Short % of Load	24%	24%	19%	20%	23%	27%
Low Load Scenario	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
ISO System Load	18,255	19,839	20,287	20,966	22,621	19,814
Real-time Net Short	4,001	4,323	2,736	3,282	4,496	4,536
Net Short % of Load	22%	22%	13%	16%	20%	23%
High Load Scenario	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
ISO System Load	19,630	22,116	24,646	24,607	26,093	23,251
Real-time Net Short	5,036	5,935	5,736	5,978	7,073	7,281
Net Short % of Load	26%	27%	23%	24%	27%	31%

The situation described by these data is sobering: First, the real-time market potentially has to serve anywhere from 19 percent to 31 percent of Load under either the normal or high load scenarios. Second, even under the low Load scenario, the real-time market potentially has to serve 20 percent of Load

[43] The real-time net short numbers reported includes PG&E and SoCal Edison real-time net short plus an assumed 5% real time net short for all other forecasted Load.

or more except for the two months when hydro supplies are likely to be the most plentiful. Third, since these numbers represent monthly totals, actual hourly percentages of system Load that have to be served in real-time may often be significantly higher than the data indicate. Fourth, to the extent the Generation and Load data provided by PG&E and SoCal Edison may have included Generation in off peak hours in excess of off peak Loads, the numbers reported here may understate the real-time net short in peak hours.[44]

As the ISO explained in its March 22 Comments on the Staff Proposal, use of a single MCP can produce just and reasonable rates but only if resource-specific bid caps are applied to all Generating Units in all hours, a modification required to ensure that bids are reflective of a properly functioning competitive market. In contrast, a single price auction with no price mitigation during many hours will allow the continued exercise of pervasive market power, resulting in further unjust and unreasonable prices.[45] Mitigating bids in all hours only partially addresses the pervasive market power being exercised in the ISO markets

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[44] The ISO expects that CDWR will continue to exercise due diligence in procuring Energy on a forward basis. Thus, depending upon the success of CDWR's efforts, the percentages reported in Table 1 may overstate the amount of Energy the ISO may have to serve in the real-time market. This issue is discussed in more detail in the ISO's Response to the Commission's April 6, 2001 order deferring action on request for suspension of underscheduling penalty and issuing request for information. *Southern California Edison Company and Pacific Gas and Electric Company,* 95 FERC ¶ 61,025 (2001). A copy of the non-confidential version of the ISO's response to the order is provided as Attachment I to this filing.

[45] On April 6, the ISO filed with the Commission a report that provides a detailed analysis of historical and forecasted near-term peak electricity supply and Demand levels for the ISO Control Area. This report, the *CAISO 2001 Summer Assessment*, was attached to the ISO's April 6 filing of its proposed Market Stabilization Plan in Docket No. EL00-95-12. The report concludes that the ISO Control Area is likely to experience significant supply deficiencies during summer 2001, forecasting a peak demand resource deficiency ranging from 600MW to nearly 3,700 MW. The fact that the ISO Control Area will likely face significant periods of reserve deficiency does not excuse the Commission from ensuring that rates are just and reasonable at all times.

during all system conditions and better protects consumers not protected under reasonable long-term purchasing arrangements.[46]

The Commission justified the limitation of price mitigation to System Emergency conditions on the ground that emergency conditions represent periods of true scarcity and thus provide opportunities for the exercise of market power. April 26 Order, 95 FERC at 61,361. The record fails to support the Commission's reasoning. The imbalance between supply and demand, and prices that can only be explained by the exercise of market power, exist in all timeframes, not just during System Emergencies. The ISO has always recognized the importance of providing incentives for new investment. But that does not justify the sanctioning of systematic market power abuse. The ISO's proposed Market Stabilization Plan ("MSP") would provide appropriate price mitigation during all timeframes while still providing essential price signals during peak hours.[47] Thus, the ISO's proposed MSP would maintain the appropriate relationship between on-peak and off-peak prices and thus provide appropriate price signals for new investment and, most importantly, effective market power mitigation.

[46] In addition, the ability to mitigate bids in all hours addresses a problem not addressed in the Commission's plan, namely, the need to mitigate locational market power. Locational market power exists when, because of system conditions such as Generator or transmission Outages, specific units must be dispatched if System Reliability is to be maintained. Reliability Must Run ("RMR") contracts are ineffective to constrain locational market power when RMR generators have the contractual ability to elect the "market option" in lieu of delivering energy at the contracted cost-based price.

[47] The ISO provided a detailed description of the MSP on April 6, 2001 in Docket No. EL00-95-012 in response to the Commission's letter order of March 30, 2001.

c. <u>The Commission's Order Establishes Improper Price Signals</u>

Although the Commission places much emphasis on the need for appropriate price signals, the mitigation scheme set forth in the April 26 Order does not result in appropriate price signals. Under the April 26 Order, mitigation occurs only when shortages are most acute. Therefore, the Order skews the relationship between off-peak and on-peak prices under competitive market conditions by mitigating prices during peak hours (when scarcity typically would result in higher prices) and letting off-peak prices remain unmitigated and high. As the Commission has recognized:

> Managerial actions that affect efficiency do not take place in a vacuum. They are influenced by our regulation and that of the state commissions. We recognize that our rules and policies can sometimes have unintended consequences that produce higher costs and higher rates. Consumers do not benefit from dysfunctional regulation.

Public Service Company of New Mexico, et al., 25 FERC at 62,033 (citation omitted). By limiting its market power mitigation to System Emergency conditions the Commission sends incorrect price signals to the wholesale Energy market and fails to mitigate bids that reflect the improper use of withholding to maintain high prices in non-peak periods.

d. <u>The April 26 Order Will Not Promote the Certainty and Stability Sought By the Commission</u>

The Commission expresses its distaste for the current "soft cap" mitigation scheme because the remedial action is *ex post*. April 26 Order, 95 FERC at 61,352. Problems cited by the Commission include the potential to alter business arrangements that may have appeared reasonable when made, the labor intensive review, and the lack of transparency in the market price. *Id*.

The Commission, however, cannot let its desire for a simplistic mitigation measure override its mandate to protect consumers. If the Commission is concerned about the difficulties in the after-the-fact review of bids under the soft cap methodology, it must nevertheless adopt an effective plan that will also promote stability and certainty. As the ISO demonstrated in its MSP proposal, price mitigation measures can be designed that are effective and that operate before the fact. Any problems associated with ex post review simply do not warrant exposing consumers to excessive prices through inadequate mitigation of market power.

C. <u>Because the Necessary Conditions for Suppliers To Charge Market-Based Wholesale Rates Do Not Exist and the Measures Adopted in the April 26 Order Are Insufficient To Constrain Suppliers' Exercise of Market Power, the Commission Must Either Limit Wholesale Suppliers to Cost-Based Rates or Condition Their Continued Use of Market-Based Rates On Effective Mitigation Measures</u>

As discussed above, the courts have been crystal clear that the Commission fails in its fundamental duty to protect consumers against exploitation when it permits wholesale suppliers to charge market-based rates in the absence of market conditions that ensure the resulting charges are just and unreasonable. The Commission itself has determined that these conditions *do not exist* for wholesale sales in California and have not existed since at least October of 2000. In fact, the evidence in the record goes further, demonstrating that the wholesale electricity markets have not been competitive, and suppliers have taken advantage of the opportunity to exercise market power, continuously since at least May 2000. The evidence also demonstrates that suppliers have collected unjust and unreasonable rates by exercising market power during all hours, not just during hours when System Emergencies were declared. For this reason, as well as the other reasons described above, the mitigation measures prescribed in the April 26 Order are entirely inadequate to constrain wholesale electricity suppliers' exercise of market power or to ensure that the revenues collected under market-based rates are just and reasonable.

The Commission is legally obligated to protect consumers by providing effective relief against the ability of wholesale suppliers with wholesale market-based rate authority to exact unjust and unreasonable charges in these circumstances. It must take either of two actions to fulfill this obligation. First, the Commission may revoke suppliers' market-based rate authority and limit suppliers' to rates that do not exceed their demonstrated costs of producing the power they supply. The ISO notes that several parties, including Governor Davis, the California Electricity Oversight Board, and the CPUC, advocate this course.[48]

If the Commission does not limit suppliers to cost-based rates, its only lawful alternative is to condition suppliers' continued use of market-based rates on the implementation of mitigation measures that the Commission confidently

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48 *See, e.g.*, Motion to Intervene and Comments of the California Electricity Oversight Board In Response to Questions Posed By Commissioner Linda K. Breathitt, Docket No. PL01-3-000 (Apr. 13, 2001), at 2; Notice of Intervention and Motion for Suspension of Market-Based Rate Authority, Or In the Alternative, Protest and Request for Hearing of the Public Utilities Commission of the State of California, Docket No. ER99-1722-004 (Apr. 2, 2001), at 2-5, 8-13; Notice of Intervention and Comments of the Public Utilities Commission of the State of California Regarding Commissioner Breathitt's Questions, Docket No. PL01-3-000 (Apr. 13, 2001), at 4.

can conclude will be *effective* to prevent the exercise of market power and ensure that *all* wholesale charges are just and reasonable in all hours of the day.[49] For the reasons described above, the measures prescribed in the April 26 Order plainly do not meet this test.

Moreover, as the ISO explained in its May 7, 2001, comments on the Commission's WSCC-wide Section 206 investigation, the fact that the April 26 Order would only mitigate prices in California creates incentives for suppliers to withhold supply from California. Due to this limited application, the April 26 Order's mitigation measures fail to foreclose opportunities for suppliers to sell energy in spot transactions at unmitigated prices. Therefore, in the May 7 Comments the ISO laid out a more comprehensive mitigation plan.[50] The ISO recommended using a WSCC-wide proxy price based on variable costs, along the lines of what the Commission has ordered for the California markets, to mitigate prices in all spot transactions throughout the region. Under this approach, "spot transactions" should include all trades that occur from the day-ahead through real-time time frames, and should include bilateral transactions (such as the out-of-market transactions the ISO relies upon in order to avoid the curtailment of firm load) as well as trades in formal markets such as the ISO's real-time market. The proxy would be based on a reference heat rate and gas price, with an adder for variable operations and maintenance costs. Additionally,

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49 *See Farmers Union,* 734 F.2d at 1510, and discussion in section III.A, above.

50 Comments of the California Independent System Operator On the Commission's Proposed West-Wide 206 Investigation and Price Mitigation In Spot Markets Throughout the WSCC, Docket Nos. EL00-95-012, *et al.* (May 7, 2001) ("May 7 Comments").

the reference heat rate should not be the highest heat rate of thermal Generation in the region, but should be set to be greater than or equal to the heat rates (at or near maximum Load) of 90 percent of the thermal Generators in the region. The reference gas price should be a weighted average of spot gas prices[51] at the major delivery points in the WSCC region, excluding California delivery points. Because 10 percent of the Generators can be expected to have heat rates higher than the reference, the Commission should allow trades to occur at prices higher than the proxy price, but only when the seller can justify the higher price based on the variable operating costs of a specific Generating Unit, and subject to Commission review and possible refund. The ISO emphasized to the Commission that under this approach, marketers must not be allowed to justify a higher price based on their purchase cost. Otherwise, the whole market power mitigation plan would fall apart. Any Generators or marketers concerned about not recovering all of their costs (purchase costs in the case of marketers) at such a proxy price would be able to avoid the proxy price simply by trading prior to the spot market time frame. The ISO believes that its approach to determining the proxy price would ensure that Generators receive sufficient payment, based on an appropriate weighting of the relevant variable costs, while simultaneously ensuring that Generators are not overpaid under a market-based rate regime.

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[51] In its May 7 Comments, the ISO proposed the use of spot gas prices throughout the WSCC region for region-wide mitigation. As discussed elsewhere in the instant filing, the ISO recommends against the use of thinly-traded and volatile spot market gas prices to set a proxy price in California. Use of spot gas prices may still be appropriate outside of California, however, because spot gas prices outside of California appear to be more competitive. The underlying issue, of course, is that a proxy price for electricity – which is intended to approximate the outcome of a competitive market – must be based on cost components that are also competitive, or else the mitigation is not effective. The ISO intends to address this issue further in its forthcoming filing of a comprehensive mitigation proposal.

The ISO's May 7 Comments also endorsed an expanded version of the Commission's proposed WSCC-wide must-offer requirement, under which all public utility suppliers with available capacity must offer that capacity for sale in spot transactions at prices at or below the proxy price, or at higher prices that would have to be justified based on the actual operating costs of a specific Generating Unit.

Unlike the limited mitigation measures prescribed in the April 26 Order, the mitigation measures proposed by the ISO would ensure that suppliers' market-based rates are within the zone of reasonableness, by foreclosing opportunities for suppliers to circumvent mitigation measures and sell energy in spot transactions at unmitigated prices. They represent the minimum mitigation measures that would justify the continued use of market-based wholesale rate authority under current market conditions. If the Commission does not revoke suppliers' market-based wholesale rate authority, it must condition the continued exercise of that authority on mitigation measures at least as stringent as those proposed by the ISO and maintain those measures in effect until the suppliers of wholesale electricity satisfy their burden of demonstrating that market conditions have improved to the extent that just and reasonable rates can be assured with less restrictive mitigation.

In addition, in order to effectively address the exercise of market power in the ISO's Ancillary Services and Congestion Management markets, the ISO advocates implementation of measures proposed in its Market Stabilization Plan. The MSP provided for the creation of a forward-market unit commitment and scheduling process that would, in conjunction with an effective must-offer requirement, ensure the forward commitment of resources necessary to serve forecasted load (thus reestablishing some sense of stability to grid operations) and satisfy reserve requirements at just and reasonable prices. The ISO's MSP would also provide appropriate incentives for the investment in new efficient generation by permitting such resources to collect the MCP established by less-efficient marginal resources. In combination with the WSCC-wide real-time price mitigation proposal outlined above, the ISO's MSP would offer effective price mitigation in all time frames and in all markets.

D. Even If It Is Appropriate For the Commission To Develop Proxy Prices To Develop a Surrogate MCP, the April 26 Order Implements the Approach In an Arbitrary and Capricious Manner

In the April 26 Order, the Commission adopts a mitigation methodology that "is a variant of the proposal made by staff and the proxy mitigation used by the Commission in the Mach 9, 2001 Order." April 26 Order, 95 FERC at 61,358. Each gas-fired Generator in California is to provide the Commission and the ISO the heat rate[52] and emission rate for each Generating Unit subject to the requirement.[53] *Id.* at 61,359. The ISO is to use these heat rates to calculate a marginal cost for each Generator by using a proxy for the gas costs,[54] emission

[52] Not including start-up and minimum load fuel costs.

[53] This includes Generating Units outside the ISO Control Area with which the ISO does not have an existing agreement for this type of information. Generating Units outside the ISO Control Area are considered System Resources under the ISO Tariff.

[54] The April 6 Order states that the gas cost proxy will use an average of the daily prices published in Gas Daily for all California delivery points. The ISO discusses the issues of the appropriate gas proxy price for California below.

costs,[55] and a $2.00 adder for operation and maintenance expenses. *Id*. The ISO will publish by 8:00 am the gas and emission figures to be used for the next day in any hour where a System Emergency is declared. The ISO's auction is to be modified to permit the Generators to elect the proxy price for gas-fired units in lieu of an individual bid above the proxy. All Generators who elect the proxy will be paid a single MCP reflecting the highest priced unit dispatched calculated using the proxy prices.[56]

California Generators that do not use natural gas can accept the MCP price calculated by the ISO during emergency situations. If such Generators believe their costs will be higher than the MCP, they can submit a higher bid, which they will be paid if the bid is accepted, subject to refund and justification. *Id*. At the end of each month in which a Generator submits a bid higher than the MCP, the Generator must file with the Commission and the ISO, within seven days of the end of the month, its complete justification, including a detailed breakdown of all of its component costs, for each transaction exceeding the MCP established by the proxy bid. *Id*. This justification must be based on a showing

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55 The emission cost will be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services ("Cantor Fitzgerald) and the emissions rate for the unit. However, as described below, the majority of the units in California do not pay emission costs to the extent that the Commission is proposing to reimburse them.

56 If the proxy bid is lower than the Generator's actual marginal costs, the Generator may submit a bid greater than that calculated through the proxy. If that bid is accepted, the Generator will be paid what it bid, subject to the submission of cost justification for the bid and refund. A Generator's non-proxy bid will not establish the MCP. However, to the extent a Generator submits a bid at or below the MCP, it will receive the MCP and will not be subject to refund liability. *Id*.

of actual marginal costs higher than the Market Clearing Price.[57] The refund obligation will end 60 days from the date of each such filing, unless the Commission, within that period, notifies the seller otherwise.

The April 26 Order further provides, with regard to bids accepted from resources located outside California, that such resources, if bidding during periods when the mitigation measures apply, can elect to be paid the MCP or can submit their own bid price.[58] During mitigation periods, marketers can also accept the market clearing proxy price or submit their own bid. If a marketer's bid exceeds the MCP, it would be required to justify the bid based on the prices it paid for power.[59]

This methodology is deeply flawed in several significant respects. If the Commission does not replace the proxy price methodology with a more effective price mitigation approach, it should at least act immediately to correct these flaws. First, it should exclude the costs of NOx emissions costs in the proxy price methodology. Second, it should modify the gas price index in accordance with the discussion below to eliminate factors that are likely to overstate the Generators' true fuel costs.

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57 Under the April 26 Order, Generators are not be permitted to include an extra cost component to represent scarcity rents since such rents are provided through payment of the MCP. Nor are they permitted to include a cost component to represent opportunity costs since, in real-time, there are no other opportunities to sell a unit's output.

58 *Id.* at 61,359-60. If they submit their own bids, such bids will not be used in setting the MCP during mitigated periods.

59 As with in-state Generators, importers are not permitted to include extra cost components for scarcity rents or opportunity costs.

In addition, there are several aspects of the April 26 Order that require clarification. First, the Commission expressly states that in-state Generators who submit a bid above the proxy MCP price during System Emergencies must file a "complete justification" for each transaction. April 26 Order, 95 FERC at 61,359. The order also expressly states that marketers can accept the proxy price or justify their bid based on the price they paid. *Id*. With respect to out-of-state Generators, the order permits these suppliers to accept the MCP or to submit their own bid. *Id*. The order does not expressly state that out-of-state Generators must provide justification for the their bids above the MCP, although there are indications that the Commission intended this requirement to apply to them. Accordingly, the Commission should clarify that these bids are also subject to justification and review by the Commission.

Second, the ISO seeks clarification, or in the alternative rehearing, on whether Combustion Turbines, or other inflexible units, may establish the MCP.[60] The April 26 Order states that "the ISO would then use the marginal cost prices to determine the market clearing price in the auction." *Id*. at 61,358. The ISO believes that due to their operational characteristics, certain units do not have the flexibility to be dispatched on a 10-minute basis consistent with the design of the ISO's real time market, and therefore should not be allowed to set the MCP. Instead, they should be required to function as price takers, and to the extent

[60] The Commission's previous proxy-price based refund orders established a proxy price using a CT with a heat rate of 18,000 BTUs as the marginal unit. The ISO assumes, therefore, that the Commission intended for such resources to be able to set the MCP under the approach set forth in the April 26 Order. The ISO respectfully requests that the Commission reconsider this determination.

their bid prices are higher than the MCP, be paid their bid price, subject to justification and potential refund.

Certain units, such as CTs, do not have incremental cost curves, cannot be incrementally dispatched on a 10-minute basis (to perform “Load following”), and due to their operational characteristics, may have to operate for multiple hours even when the marginal Energy in intervals subsequent to the initial dispatch of the inflexible unit is produced by another Generator at substantially lower cost. Moreover, CTs typically either run at maximum output or are off; they cannot be dispatched at intermediate levels to provide exactly the amount of Energy needed. Other operationally constrained units may be “constrained on” or provide more Energy than the market may optimally require due to their minimum operating levels. Allowing these “inflexible” resources to set the MCP at times when their levels of output are dictated by operating constraints and would not otherwise be needed to serve Load or maintain reserves will significantly distort the market price signals the April 26 Order intends to provide. It is therefore inconsistent with marginal cost pricing to let these inflexible resources set the MCP. These resources should be paid the MCP when dispatched if their cost is lower, and should be paid as bid if their cost is higher.[61] They should not, however, be used to set the MCP.

[61] Additionally, such an approach to paying for Energy from CTs would assist in remedying problems that decrease the supply of Regulation and the availability of Supplemental Energy from other Control Areas.

1. <u>There Is No Foundation For the April 26 Order's Proxy Price</u>

The ISO believes that the factors used to determine the proxy price under the April 26 Order are unfounded and will unreasonably inflate the MCP. This will also result in overstating the rates necessary to serve as an incentive to attract new Generation.

a. <u>The April 26 Order Overstates NOx Compliance Costs</u>

The April 26 Order requires the ISO to include emission costs in its proxy MCP calculation based on data from Cantor Fitzgerald. April 26 Order, 95 FERC at 61,359. In its request for rehearing of the Commission's March 9 Order, the ISO informed the Commission that the use of the Cantor Fitzgerald data was inappropriate and improperly inflated the proxy MCP.[62]

First, the ISO noted that the NOx RECLAIM[63] market affects only thermal power Generating Units in the South Coast Air Quality Management District ("SCAQMD")[64] and that these units account for approximately 20 percent of the power generating capacity in the state.[65] Accordingly, the Commission is making

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62 Application for Rehearing of the California Independent System Operator Corporation, Docket No. EL00-95-017, et al. (April 9, 2001) at 23-29.

63 The Regional Clean Air Incentives Market ("RECLAIM") was adopted by the South Coast Air Quality Management District in October 1993. RECLAIM regulates emissions on a mass basis rather than limiting emission rates and was implemented to provide facilities with added flexibility in meeting emission reduction requirements while lowering the cost of compliance.

64 The SCAQMD includes Los Angeles and Orange counties and parts of Riverside and San Bernardino counties. The ISO notes that part of this area is outside the ISO Control Area.

65 *See* testimony of Michael H. Scheible, Deputy Executive Officer of the California Air Resources Board at 4-6. This testimony was provided as an attachment to the November 22, 2000 comments of the California Public Utilities Commission in Docket No. EL00-95-000. *See also* the Motion of the California Air Resources Board for Expedited Consideration and for Limited Rehearing and Clarification or, in the Alternative, for Partial Stay and a Technical Conference filed in this proceeding on May 25, 2001, and provided as Attachment A to this filing, at 9.

assumptions not only about the operating characteristics of the hypothetical marginal unit, but also its location. Generators located outside the SCAQMD are subject to different environmental rules and regulations.

Second, the ISO stated that Generators in SCAQMD are given, at no cost, annual baseline amounts of credits and would only need to purchase additional credits if they exceed this allocation. By simply multiplying the emission rates by posted prices the Commission continues to assume that these allocations have been completely exhausted.

Third, the ISO reported on a series of events that recently have changed the SCAQMD NOx RECLAIM market:

(1) The issuance of a proposed rule that would: (a) bifurcate the RECLAIM market between electric Generators and non-utility facilities, suspending the RECLAIM rules for power Generators over 50 MW;[66] (b) freeze the number of RECLAIM Trading Credits ("RTCs") available for Generators' use at their original allocation plus any purchases made through January 11, 2001; and (c) offset any emissions in excess of these available RTCs by a payment of \$7.50/lb.

(2) The adoption of a series of orders from the SCAQMD Executive Director implementing the new rule. The ISO stated that it

[66] The proposed rule would separate existing Generating Units over 50 MW for the 2001 through 2003 compliance years. These Generators would not be allowed to rejoin the other RECLAIM participants until the Air Resources Governing Board concludes that their reentry for the 2004 Compliance year would not result in any negative impact on the remainder of the RECLAIM universe or California's energy security needs.

understood that Executive Order #01-03 placed the provisions of the proposed rule in affect *retroactive* to January 11, 2001.

On May 9, 2001, the Commission requested additional information from SCAQMD. Mr. Barry Wallerstein, the Executive Director of SCAQMD, responded by letter dated May 16, 2001.[67] SCAQMD informed the Commission that the proposed rule discussed by the ISO had been adopted so that "[t]here are presently no power Generators over 50 MW participating in the [RECLAIM Trading Credit] program." Wallerstein letter at 2. SCAQMD also stated that effective February 6, 2001, its executive orders had permitted large power producing facilities to exceed their emissions allocations by paying a mitigation fee of $7.50 a pound.[68]

The California Air Resources Board ("CARB") has filed a motion for clarification, limited rehearing, expedited consideration and a technical conference.[69] The filing was supported by the Testimony of Michael Scheible, Deputy Executive Officer of CARB, and David Viadaver, an electricity market analyst with the California Energy Commission ("CEC").

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67 A copy of the letter is provided as Attachment J to this filing.

68 Based on additional information from SCAQMD, the ISO understands that January 11, 2000 is the date staff first publicly proposed to amend RECLAIM and proposed to preclude power-producers from using any RTCs acquired after January 11 to reconcile their emissions. The adopted RECLAIM amendments, however, allow the use of RTCs purchased after January 11 and registered prior to May 1, for reconciling emissions for the first quarter of the 2001 calendar year (prior to April 1). Thus, no RTCs purchased after January 11 may be used to reconcile any emissions after April 1, 2001. The ISO will be filing a correction to its request for rehearing of the March 9 Order on this issue and noting the February 6, 2001 effective date.

69 As indicated above, a copy of the CARB motion is provided as Attachment A to this filing.

In its motion, CARB reemphasized that the RECLAIM program is limited to SCAQMD and that more typically emission reduction credits are obtained before operations are even started and then become fixed over the life of the project. CARB Motion at 9. Accordingly, it contends that an emission cost factor should not be included in the calculation of the proxy bid price designed to emulate the marginal variable cost of producing electricity. *Id.* at 11-14. CARB also contends that the Commission's proposal with respect to emissions costs will have significant adverse environmental impacts. *Id.* at 14-22.

The ISO agrees with CARB that emissions costs should be excluded from the proxy price calculation. Clearly, use of the Cantor Fitzgerald data is inappropriate, as large Generators, even within the SCAQMD, are exempted from the RECLAIM program. Furthermore, it is inappropriate to assume that the MCP will always be set by a unit within SCAQMD that has exceeded its allotted credits and is subject to an offset payment.

Given the disparate treatment of California gas-fired generators' emissions (as noted by the CARB, there are thirty-five separate air districts in the state)[70] and the fact that for many Generating Units the emissions costs represent a fixed cost and not a variable cost, the only appropriate course is to exclude emissions from the proxy price calculation. Of course, Generators would still be permitted to justify individual bids above the proxy price based in part on emissions costs.

Elimination of the emissions cost factor is also appropriate given the asymmetrical risk posed by the Commission's mitigation methodology.

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[70] CARB Motion at 7.

Generators are permitted to bid above and justify costs of service above the proxy MCP, thereby ensuring full cost recovery. Conversely, consumers are not given the data or the opportunity to demonstrate that the proxy methodology greatly overstates the true variable costs of the marginal unit. Thus, they are exposed not only to potentially excessive prices for the facility that set the MCP, but also for suppliers in the market at that time whose costs were below the MCP. If experience demonstrates that significant numbers of Generators are justifying variable operating costs above the proxy MCP due to emissions costs, the Commission could always revisit and adjust the formula.

b. The Proxy For the Generator's Gas Procurement Costs in the April 26 Order Is Unsupported

The gas cost proxy established by the Commission is based on "an average of the daily prices published in Gas Daily for all California delivery points." April 26 Order, 95 FERC at 61,359. As discussed below, the ISO believes that the use of daily prices will overstate the Generators' true fuel costs and requests that the Commission require the use of the "Bid-week" monthly price.

First, the ISO seeks clarification that the Commission intends for it to use a simple average of the Gas Daily mid-point index prices for Malin, the Southern California Border ("SoCalGas large pkgs.") and PG&E Citygate. Gas Daily also cites prices for Kern River Station and PG&E large packages, both of which reflect gas deliveries into Southern California. While the ISO believes it is appropriate to include a Southern California index point, including all three indices into the average state index price would inappropriately weigh the index towards a Southern California price. The ISO proposes to use the SoCalGas large pkgs. index as the single point for Southern California, as it reflects gas transactions for virtually all Southern California pipelines and represents the largest quantity of gas transactions of the three indices. In addition, while Malin is not physically within California it is generally recognized as a California delivery point. [71]

Second, the ISO requests rehearing on the use of daily average gas prices as the proxy price for natural gas consumed by Generators when the ISO implements real time price mitigation. The ISO believes using daily market-priced gas as a proxy for actual gas costs incurred by Generators is inconsistent with the goals of market mitigation – to replicate the true marginal costs of producers. Gas-fired Generators do not procure all gas supplies on the spot market; rather, they purchase a portfolio of gas supply including spot, short-term and long-term.

Moreover, the Commission recently set the issue of a major California natural gas supplier's potential exercise of market power for hearing in Docket No. RP00-241-000. *Public Utilities Commission of the State of California vs. El Paso Natural Gas Company, et al.*, 94 FERC ¶ 61,338 (2001). If this investigation finds that gas prices were unjust and unreasonable due to the

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[71] It should be noted that the Commission, in approving the ISO's Must-Run Service Agreements ("RMR Agreement") with various Generators, has already found to be just and reasonable gas prices based on the Service Area where the Generator is sited. Specifically, the RMR Agreements provide for averaging Gas Daily, SoCal Gas, Large Packages index (midpoint); BTU Daily Gas Wire, SoCal Border index, Topock; and NGI Daily Gas Price Index, Southern California Border (average) to determine the gas index for SoCal Edison and SDG&E Service Area. For PG&E's Service Area the gas index is the average of Gas Daily, PG&E Citygate index (midpoint) and NGI Daily Gas Price Index, PG&E Citygate (average).

exercise of market power, then the Commission must make corresponding adjustments to the rates charged by wholesale electric suppliers until adequate market power mitigation measures are in place in the gas transportation market.

On May 18, 2001, the Commission issued an Order Proposing Reporting Requirement on Natural Gas Sales to California Market and Requesting Comments in Docket No. RM01-9-000, 95 FERC ¶ 61,262. The Commission stated that, in December 2000, the spot price range at the California border was $11.79-$18.80 while in other markets the spot price range was between $4 and $7, and further declared that this disparity continues. *Id.*, slip op at 1-2. The Commission noted that "[a]t present, the Commission does not have reliable information concerning the percentage of gas moving into the California market that is actually priced at the high spot market prices reported at the California borders." *Id.*, slip op at 4-5. Given the absence of "reliable information," the Commission should not rely on the spot price for its mitigation methodology. Due to the extreme price volatility in the California gas market recently, and the prospect that this volatility is the result of non-competitive market behavior rather than fundamental supply and demand forces, the ISO believes it is inappropriate to have prices for wholesale electricity established, in part, by the prices produced in such a suspect market.

The ISO believes that a more representative index is the mid-point of the "Bid-week" monthly price, which is also reported in Gas Daily. Advantages of the "Bid-week" monthly price include the following: (1) it represents real transactions at the same delivery points used for the spot market index; (2) it better reflects the true costs of gas to Generators purchasing gas on a portfolio basis, and (3) it is used for physical delivery of gas as well as being a financial product. Accordingly, if the Commission retains the price mitigation approach set forth in the April 26 Order, the ISO respectfully requests that the Commission act immediately to modify the gas component of the proxy price formula to mandate use of the "Bid-week" monthly price in that formula.

2. The April 26 Order Overstates the Rates Necessary to Attract New Generation

The Commission states its desire to create a plan that would not discourage the critically needed investment in new Generation. April 26 Order, 95 FERC at 61,354. While the courts have recognized that encouragement of new supply is a permissible objective for the Commission to pursue, the rates *must not be more than is needed for the purpose*:

> While as we have indicated the Commission may be empowered to consider some of these factors *it must also, and always, relate its action to the primary aim of the Act to guard the consumer against excessive rates*. If 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.

City of Detroit v. Federal Power Com'n, 230 F.2d 810, 817 (1955) (emphasis added). The court affirmed this determination in *Farmers Union*, criticizing the Commission for failing to "even attempt to calibrate the relationship between increased rates and the attraction of new capital." *Farmers Union,* 734 F.2d at 1502-03.

The study by Dr. Hildebrandt discussed above also examined wholesale prices in relation to the cost of investment in new supply. The results indicate that, on an annualized basis, wholesale prices since January 2000 have exceeded the cost of new capacity by approximately 400 percent and would allow recovery of an investment in a new supply resource with a useful life of decades in a period of less than two years.[72]

The ISO recognizes the importance of new Generation to California. The State is making significant strides in expediting the approvals for new facilities. In addition, the ISO recently filed Tariff revisions to implement its "New Facility Interconnection Policy," setting forth interconnection procedures for new Generators that are designed to reduce interconnection costs, create clear non-discriminatory procedures for interconnection, and thereby eliminate barriers to entry. Nevertheless, the need for new supply does not justify excessive prices well beyond those necessary to fulfill this objective.

Moreover, in its March 30, 2001 Comments in Docket No. EL01-47-000, the CEC noted that, as of March 21, 2001, the CEC had already licensed 8,464 MW of new central station generation which is in various stages of construction and anticipated to be operational by 2003; that an additional 5,000 MW of generating capacity is currently under siting consideration; and that applicants for another approximately 8,000 MW have indicated they will be seeking operating certificates during the next year. March 30, 2001 Comments at 2-3. The CEC stated that the State is negotiating long-term contracts to

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[72] *See Further Analyses of the Exercise and Cost Impacts of Market Power in California's Wholesale Energy Market*, dated March 2001. This study was attached to the ISO's Comments on Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market, filed in Docket No. EL00-95-12 on March 22, 2001. The analysis is based on a typical 500 MW combined cycle unit, since the majority of projects proposed in California and the WSCC during the last three years have been 500 MW gas-fired combined cycle plants.

encourage continued power plant construction and that "[c]ontinued or increasing high prices beyond any reasonable level, instead of causing more power plant applications this year, will simply aggravate a burden-of-payment and credit crisis that increasingly clouds the financial outlook for both existing and new projects." *Id*. at 4. As Commissioner Massey has recognized,

> Soaring prices will not get even one more megawatt of generation built by this summer. Not one. The price signal has been sent. For this summer, high prices are all pain, no gain. I fear that high prices are already damaging the western economy.

Transcript of the April 10, 2001 conference in Boise, Idaho at 19.

The CEC's comments are in agreement with the testimony of Ms. Marilyn Showalter, the Chairwoman of the Washington Utilities and Transportation Commission:

> In other words, the very prices that you hope are sending signals to develop new supply or to bring on existing supply are, in fact, producing such instability and such uncertainty on the west coast, that they are accomplishing the opposite effect.
>
> * * *
>
> [a]n unfettered price signal to resource developers is useless for bringing [on] new capacity, if at the same time[, i]t produces instability and uncertainty such that the financial markets are not willing to commit capital. And this is the story that I hear.[73]

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[73] *Id*. at 31. *See also* the testimony of Mr. Roy Hemmingway, energy advisor to Governor Kitzhaber of Oregon, posing the question, "will unregulated prices bring additional generation into the marketplace in time to meet the immediate problem of lack of generation in the western marketplace? And I think the answer to that clearly is no," and the testimony of Ms. Connie White of the Utah Public Service Commission quoting Alfred Kahn for the proposition that "[p]rices can skyrocket to unproductively high levels where the pain inflected outweighs the relatively small benefit. The amount of additional conservation and additional imp[etus] to build more capacity you'll get is not worth it," and suggesting that "[w]e may have reached this point in the west." *Id*. at 79 and 36. With regard to the "question of whether the inherently volatile market prices for energy can send appropriate price signals to the changing s[uppliers] of new generation," Ms. White expressed her "agreement with what Chairwoman Showalter was saying." *Id.* at 37.

E. <u>The Commission's Failure To Mitigate Bids for Ancillary Services and Congestion Management Will Lead To Unjust and Unreasonable Prices</u>

1. <u>Ancillary Services</u>

It appears that the real-time mitigation scheme proposed in the April 26 Order, in its replacement of the $150/MW "soft cap" put in place by the December 15 Order, would leave Ancillary Services capacity bids entirely unmitigated.[74] There is absolutely no justification offered for leaving the Ancillary Service Market without such protection. The Commission must act expeditiously to redress this oversight.

This is not a trivial matter. Ancillary Services costs are significant in California, and are a causative factor of higher costs in the ISO's real-time Imbalance Energy market.[75] It is no wonder, therefore, that price mitigation in the ISO's Ancillary Services Market has been in place since the summer of 1998 and have been included as necessary components of the mitigation regime currently in place. The ISO is frankly uncertain what may have caused a change of Commission attitude resulting in the removal of such protections. The ISO surely is not aware of any theoretical or empirical justification for doing so.

As the ISO explained in its request for rehearing of the December 15 Order, there can be no cost justification for bids above $150/MW in the Ancillary Services capacity markets. Bidders in the Spinning, Non-Spinning, and

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74 In the ISO's compliance filing with the April 26 Order, submitted in this proceeding on May 11, 2001, the ISO eliminated Tariff provisions related to the $150/MW soft cap on Ancillary Services capacity.

75 *See, e.g.*, *Report on Redesign of Markets for Ancillary Services and Real-Time Energy*, prepared by the ISO's Market Surveillance Committee, filed in Docket Nos. ER98-2843-007 *et al.* on March 25, 1999, at 3-14.

Replacement Reserve markets submit Energy bids along with their capacity bids. If the bid is selected for the Ancillary Service, but the Energy associated with this capacity is not dispatched, then the bidder only receives the capacity payment. When the ISO dispatches Energy from the capacity selected for one of these Ancillary Services, the bidder is assured of payment in accordance with its Energy bid, which it is now free to set at any level it deems necessary to recoup its costs of providing the Ancillary Service. Since the payments such bidders receive for their Energy bids are no longer subject to a hard price cap, bidders can recover all reasonable costs through their Energy bids.

Should the Commission grant rehearing on this issue and impose price mitigation in the ISO's Ancillary Service markets, the ISO requests that the Commission clarify its statements with respect to opportunity costs.[76] As the ISO previously stated, the cost of providing Ancillary Services is the opportunity cost associated with not selling Energy. Thus, the Commission should clarify that the price mitigation applicable to the sale of Ancillary Services capacity is the difference between the resource's cost of producing Energy and the price of Energy.[77] Since the ISO would not be able to implement such an approach immediately, the ISO believes the Commission should at least retain the $150/MW soft cap on Ancillary Service capacity bids.

The ISO believes such an approach presents an absolute minimum mitigation methodology and that a hard cap, or at least a lower "soft cap" is

[76] *See* April 26 Order, 95 FERC at 61,359 n. 29.

[77] Mitigation of Ancillary Service prices based on such an approach was proposed in the ISO's Market Stabilization Plan.

justified. As noted above, DMA prepared an evaluation of the cost of new facilities.[78] The result was an installed cost for a new combined cycle plant of $600/kW and an installed cost for a new peaking plant of $420/kW.[79] With regard to a combined cycle unit, if one were to assume an availability factor of 85 percent (7,500 hours) and that the plant is selling its full capacity in either the Energy or Ancillary Services markets during those hours the plant would need to recover $16.63 per MWh to meet its fixed revenue requirement, assuming a carrying cost of 17.45 percent. For the peaking plant, if one were to assume an availability of 800 hours, the plant would need to recover $104.11 per MWh to meet its revenue requirement through Energy sales alone. If the peaker had 2,000 hours of sales of either Energy or Capacity, the per-MW recovery price drops to $41.65/MWh. Furthermore, the opportunity cost of providing Ancillary Services, assuming a zero probability of being dispatched for Energy, is the difference between the expected Energy price and the unit's marginal cost. Under a proxy price regime, it is unlikely that the difference between a unit's marginal cost and the proxy MCP would ever exceed $150/MWh[80]. Moreover, this would most likely only happen during peak hours where a high cost unit is setting the MCP. Under such conditions, a low cost infra-marginal unit providing

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[78] *See Further Analyses of the Exercise and Cost Impacts of Market Power in California's Wholesale Energy Market*, dated March 2001. This study was attached to the ISO's Comments on Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market, filed in Docket No. EL00-95-12 on March 22, 2001.

[79] *Id.* at 13-17.

[80] For example, with a gas price of $10/MMBTU, the marginal cost spread between a relatively efficient and inefficient unit is roughly $100/MWh (*i.e.*, comparing a unit with an incremental heat rate of 10,000/BTU/KWh versus a unit with an incremental heat rate of 20,000/BTU/KWh).

Ancillary Services will most likely have some if not all of its reserved capacity dispatched for Energy and thus would not have to completely forego the opportunity to earn scarcity rents from the Energy market.

In addition, the Commission's recent approval of the ISO's "BEEP split" proposal in Amendment No. 38 to the ISO Tariff[81] enhances the ability of energy-limited resources (such as hydroelectric units, which are constrained by water availability, or CTs, which are often constrained by environmental regulations) to participate in the ISO's Ancillary Services markets and earn capacity payments there. Sufficient opportunities now exist, and will exist even if the Commission follows the ISO's recommendation to mitigate prices in all hours, for Generators to recover their fixed costs. In light of all these factors, a $150/MW cap on the capacity payments in the ISO's Ancillary Service markets is more than generous and should be reinstated.

2. Adjustment Bids

The ISO also understands that the April 26 Order vitiates the existing hard cap of $250 currently in effect on Adjustment Bids.[82] Again, the Commission achieves the result of eliminating price mitigation for an ISO market – in this case the Congestion Management market – without discussion or any apparent rationale. Such an action is arbitrary and capricious and may result in significant harm to consumers.

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[81] *California Independent System Operator Corp.*, 95 FERC ¶ 61,199 (2001).

[82] Thus, in its compliance filing, the ISO was constrained to eliminate the current $250 hard cap for Adjustment Bids, effective May 29, 2001.

The December 15 Order directed the "ISO, PX and other affected scheduling coordinators to work out the most expeditious way to calculate usage charges for congestion management." December 15 Order, 93 FERC at 62,010. As explained in the ISO's January 2, 2001, compliance filing in Docket Nos. EL00-95 *et al.*, there were and are compelling reasons to retain a "hard" cap on Adjustment Bids submitted as part of the ISO's Congestion Management process.

In the January 2, 2001, compliance filing, the ISO explained that the need to retain a hard cap of $250/MWh was related to implementation concerns with regard to the PX, concerns that obviously do not exist given the collapse of the PX market. However, it is important for the Commission to remember that the sole purpose of those Adjustment Bids is to permit Market Participants to indicate the value they place on use of constrained transmission paths. The ISO uses the Adjustment Bids submitted by Market Participants to determine the marginal value for use of a particular transmission path (*i.e.*, the Usage Charge applicable to that constrained path). Given the supply situation facing California this summer, and the need to rely on import supplies during high Load hours, the uncertainty associated with unmitigated Congestion costs can be a significant impediment to import suppliers offering and scheduling supplies into California on a forward basis. Thus, if the overriding objective of the Commission's price mitigation proposal is to limit the volatility and magnitude of wholesale Energy prices, it must recognize that the potential for high and volatile Congestion charges will be counter-productive.

A hard cap of $250/MWh for Adjustment Bids continues to be appropriate and necessary for additional reasons. First, the price differential between the costs of production between the ISO's Congestion Management Zones should not exceed this figure. Second, the $250/MWh level provides a strong price signal with respect to the need to proceed with transmission expansion; and three, the $250 hard cap was in place when the ISO conducted its most recent auction of Firm Transmission Rights ("FTR") and may well have been factored into the expectations of the FTR purchasers. The Commission has offered no analysis as to why mitigation in the Congestion Management market is no longer required. Given all the other changes engendered by the April 26 Order, current market conditions, and the prospects for continued crises in the California wholesale electricity market, the reasonable and prudent course is to maintain the existing mitigation measures for Congestion Management.

F. The Proposed Demand Response Requirement Exceeds the Commission's Statutory Authority, Is Inconsistent With the Prior Orders on Creditworthiness, and Is Inconsistent with Existing State Programs

In the April 26 Order, the Commission proposed to require each public utility purchasing electricity in the ISO's real-time market to submit Demand-side bids that will indicate the price at which Load will be curtailed and will identify the Load to be curtailed. The Commission stated that the bids will indicate the maximum prices that the purchaser is willing to pay for specified amounts of electricity and the Loads on its system that would be curtailed when the applicable real-time energy price exceeds the bid. The Commission also proposed that the ISO curtail service to the purchaser in accordance with its bids.[83] The Commission stated, among other things, that "requiring demand side bidding will provide downward pressure on wholesale prices since sellers will recognize the ISO will not pay any price to obtain power."[84] These proposed changes would go into effect beginning on June 1, 2001.[85]

As a threshold matter, the Commission should clarify whether the proposed changes would require public utilities to indicate the price at which they are willing to invoke rotating outages for blocks of end-use customers, or whether the changes would simply require public utilities to submit Demand bids for large users who are willing voluntarily to reduce their hourly consumption in response to real-time prices. As explained below, if the first is the intended interpretation, then the portion of the April 26 Order having to do with Demand response must be rejected as unjust, unreasonable, and beyond the scope of the Commission's authority. The ISO assumes, therefore, that this is not the intended interpretation. Nevertheless, even limited to customer-driven initiatives, the proposal poses implementation problems and may be unnecessary given other initiatives that currently are underway.

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[83] April 26 Order at 61,357.

[84] *Id.* at 61,358.

[85] *Id.* at 61,357.

1. It Would Be Unjust, Unreasonable, and in Violation of its Statutory Authority for the Commission To Require Rotating Block Outages

If the Commission is suggesting that public utilities need to indicate a price at which they are willing to invoke rotating outages of blocks of end-use customers, then the Commission's proposed changes cannot be justified for several reasons.

First, the ISO and the IOUs cannot selectively curtail service to specific Loads or customers off of the same distribution circuit. When a Stage 3 System Emergency is declared and involuntary curtailment of firm Load is required, the ISO must follow the applicable Load-shedding procedures that have previously been developed, approved by the CPUC and filed with this Commission along with the Utility Distribution Company ("UDC") Operating Agreements executed between the ISO and the UDCs. These procedures take into account the reliability requirements of the ISO Controlled Grid in implementing such blackouts. Under the procedures in place today, the ISO notifies the applicable UDCs of the amount of firm Load (in MW) that must be curtailed to maintain reliable system operation, and the UDC then curtails Load on its distribution system, by blocks, according to predetermined and pre-approved Electrical Emergency Plans.

Second, there is no jurisdiction for requiring IOUs to submit prices above which they will refuse to serve their customers, if that is what the Commission intended in the April 26 Order. The Commission's jurisdiction generally extends only to the selling end of wholesale transactions, and certainly not to the buying end of retail transactions.[86] Establishment of a maximum price for retail customers to pay for service is at the heart of state jurisdiction over retail service. Indeed, in its November 1, 2000 Order, the Commission recognized Demand side response as a matter "that lies primarily within the control of state policymakers," and classified Demand response programs (though not Demand side bidding, as discussed below) under the category of "Actions Others Should Take."[87] Like Demand response programs, Demand side bidding is a State prerogative, and for good reason. A Demand side bidding program will be effective only to the extent that retail customers voluntarily participate in it; to be effective, the program must be responsive to the particular circumstances in a given state or locality; moreover, such a program will be possible only when appropriate billing, metering, aggregating, and pricing arrangements are in place – which arrangements are regulated by the state.[88] Nowhere does the Commission explain how mandatory Demand side bidding differs in any fundamental respect from those Demand response programs that "lie primarily

[86] *See* Section 201 of the Federal Power Act, 16 U.S.C. § 824 (1994) (providing that sales of electricity at wholesale in interstate commerce are subject to exclusive federal jurisdiction, but that federal jurisdiction extends only to those matters that are not subject to regulation by the states).

[87] November 1 Order, 93 FERC at 61,372-73.

[88] The ISO certainly wishes to encourage retail customers to reduce their demand as much as practicable, and in fact has undertaken a number of demand side initiatives to encourage demand response. *See* March 22 Comments at 22-26. Moreover, the ISO has explained that the requirements of load-serving entities must be coordinated with state demand reduction efforts. *See id.* The point the ISO wishes to emphasize is that the Commission should not exceed its jurisdiction to further the accomplishment of these laudable goals.

within the control of state policymakers," or how a Demand side bidding requirement might lie within the Commission's jurisdiction.[89]

The ISO recognizes that it has filed several Tariff amendments seeking to enhance the participation of Demand-related bids in the ISO Markets.[90] It is one matter, however, to provide an incentive for voluntary demand bidding; it is quite a different matter, and one that implicates jurisdiction, where participation is to be forced.

Third, there is currently no infrastructure in place to operate an adequate Demand side bidding program. As San Diego Gas & Electric Company has noted, it is the CPUC that determines the billing, metering, aggregating, and pricing arrangements that need to be put in place to facilitate Demand side bidding, and the CPUC has yet to complete its examination of the issues.[91] Even if the Commission were competent to require, it simply would be premature to prescribe a June 1, 2001 effective date.[92]

Fourth, the CDWR – which is not a public utility – is making the decisions with regard to whether or not to back the ISO's purchase of Imbalance Energy on

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[89] *See* November 1 Order, 93 FERC at 61,366, 61,372-73; April 26 Order, 95 FERC at 61,358.

[90] *See* Amendment Nos. 17 and 28 to the ISO Tariff. These amendments were approved by the Commission in *California Independent System Operator Corporation*, 88 FERC ¶ 61,182 (1999), and *California Independent System Operator Corporation*, 91 FERC ¶ 61,256 (2000), respectively.

[91] *See* Request for Rehearing and Comments of San Diego Gas & Electric Company, Docket Nos. EL00-95-012, *et al.* (May 8, 2001), at 21.

[92] As the ISO explained in the March 22 Comments, "it is realistic to expect that only a nominal amount of price responsive demand will be in place this summer and that most of that will come from emergency activated programs and general conservation programs." March 22 Comments at 22.

behalf of Load-serving entities in real-time. Even if the Demand bidding requirement could be imposed on jurisdictional utilities, it could not be imposed on CDWR.

In these circumstances, to comply with the April 26 Order, a public utility would have to make an arbitrary and uninformed guess as to the maximum price that each of its customers would be willing to pay, and then curtail service whenever the real-time Energy price exceeded that arbitrary level. One of two results would be almost certain: either (1) the utility would guess too high, in which case customers would be forced to pay more for electricity than they would be willing to pay; or (2) the utility would guess too low, in which case customers would have their service curtailed and thus not receive electricity for which they would be willing to pay. Either of these results would be unjust and unreasonable, would be fraught with legal and/or health and safety issues, and would not support efforts to develop retail Demand response, which is what the Commission claims its proposal will do.[93] Moreover, the Commission would be undermining its own determination that "the allocation of short supplies – through rolling blackouts – is arbitrary and inefficient."[94] For all of the reasons described

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93 *See* April 26 Order, 95 FERC at 61,358.

94 *Id*. at 61,358. In addition to the difficulties described above, it is unclear how the MCP to be employed during mitigated hours would be determined. In one place in the April 26 Order, the Commission states that the MCP will reflect the highest priced unit dispatched calculated using the proxy prices. *See id.* at 61,359. In another part of the April 26 Order, however, the Commission indicates that when the demand for Energy exceeds the supply, a Demand bid can set the price. *See id.* at 61,364 n.47.

Additionally, a Demand bidding requirement would pose a significant implementation issue. To satisfy the first interpretation of the April 26 Order described above, there would necessarily have to be a real-time market where the MCP is determined through the intersection of price elastic Demand and supply curves. As explained below, as a practical matter, the ISO real-time market does not operate this way and cannot be changed to operate this way in time for above, such an interpretation of the Demand response portion of the April 26 Order should not be adopted.

2. <u>A Requirement for the California IOUs To Submit Demand Bids on Behalf of Their Large End Use Customers Would Conflict With Existing Programs</u>

Alternatively, if the Commission intended public utility purchasers to submit Demand bids for large users who are willing to *voluntarily* reduce their hourly consumption in response to real-time prices, the ISO already has appropriate programs in place. As the ISO has explained,[95] the ISO has initiated several programs designed to encourage demand response, including: (1) facilitating price-responsive Demand (*e.g.*, the ISO Participating Load Ancillary Services Program and ISO Discretionary Load Curtailment Program), (2) conservation campaigns (*e.g.*, public announcements and the PowerWatch communications initiative), and (3) Demand curtailments under System Emergency conditions (*e.g.,* the ISO Demand Relief Program and UDC interruptible Load programs). In particular, the ISO's Participating Load Ancillary Services Program provides certain Loads with the opportunity to submit bids in the ISO's markets for Non-Spinning Reserves and Replacement Reserves. In coordination with State authorities, the ISO is working with the utilities to develop a variation of the ISO Discretionary Load Curtailment Program that would allow

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Summer 2001. The ISO real-time market currently treats Demand bids as a supply resource where Demand indicates the price at which it is willing to be paid to curtail. This is a different concept than a Demand bid that indicates the price at which a customer chooses not to buy.

[95] See March 22 Comments at 22-26; Comments of the California Independent System Operator Corporation Concerning Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States and Requesting Comments on Further Actions To Increase Energy Supply and Decrease Energy Consumption, Docket No. EL01-47-001 (Apr. 3, 2001) at 16-17.

for pricing "tiers." The bids would be dispatched by the ISO based on whether they compete with Generation bids. The CDWR would provide financial backing, and the IOUs would aggregate their loads. The state has set an aggressive target of July 1, 2001 for implementation of this program including expedited installation of interval metering.

In addition, California has underway a number of Demand reduction efforts (*e.g.*, the contemplated installation of interval meters to facilitate implementation of real-time pricing and thus true Demand responsiveness). The California Legislature recently appropriated funding for real-time metering systems. Assembly Bill 29x allocates $35 million dollars for the installation of real-time metering systems for all bundled service customers with maximum demand greater than 200 kW. The CEC is currently working with public utilities to install as many of these meters as is possible for this summer. Additionally, the CEC, CPUC, and CDWR have efforts underway to implement a real-time pricing program for this summer. Though the ISO will not see these Demand bids in its real-time market, the effect will be essentially the same. Under these programs, during periods when supply margins are tight and Energy prices high, end-users will either be paid to curtail Demand or curtail Demand to avoid paying high prices, and the reduced Demand will translate into lower Imbalance Energy prices in the ISO's real-time Energy market. With a smaller amount of Load being served in real-time, the real-time market should clear at a lower part of the supply curve and will result in a lower MCP, just as would be the case if the ISO actually had a price-responsive Demand curve in its market.

It is not clear how the Commission intended the MCP to be set during the hours in which price mitigation applies. The April 26 Order states, in part, that the MCP will reflect the highest priced unit dispatched calculated using the proxy prices. April 26 Order, 95 FERC at 61,359. However, the order also states that when the demand for Energy exceeds the supply, a Demand bid can set the price. *Id.* at. 61,364, n.47. These statements appear to be in conflict. Moreover, the Commission's order also appears to contemplate a real-time market where the MCP is determined through the intersection of price elastic demand and supply curves and awarded bids (both demand and supply) are settled at the MCP. The ISO's real-time market does not operate this way. Under the ISO's current market design, curtailable Demand bids are treated as a supply resource where Demand indicates the price at which it is willing to curtail. Payments to supply and Demand bids dispatched in the real-time markets are determined by reconciling each unit's schedule and Dispatch instructions with the metered output of the Scheduling Coordinators' ("SCs") entire portfolio. The ISO believes this important difference in market design raises a serious gaming problem if Demand bids are allowed to set the real-time price during mitigated hours.

The gaming problem arises from the fact that unlike a market where settlement is based on submitted bids (*e.g.*, the former PX Market), the ISO real-time Energy market is settled by reconciling metered output with schedules and dispatch instructions. This distinction means that there is no risk for a Scheduling Coordinator ("SC") who wishes to drive up the real-time price, to submit a fictitious Demand bid for a very large amount of Load at a very high price. If the bid is dispatched (*i.e.,* curtailed) and sets a high MCP, the SC has accomplished its objective. While this SC will suffer the subsequent loss of payment for failure to curtail the fictitious Load, it will more than compensate by receiving the inflated MCP for the real-time Energy provided by its generating resources. If the bid is not dispatched (*i.e.*, the MCP is below the Demand bid), the SC has no purchase obligation for the uncurtailed Load at that price since it has no real Load behind that bid (*i.e.,* its metered Load is equal to its scheduled Load, both of which could be zero). In a market where settlement is based on submitted bids, this game is mitigated by the fact that a participant would have to pay this inflated Energy price for any Demand bid that is not curtailed. The ISO is very concerned that, if it allows Demand bids to set the clearing price during mitigated hours, this gaming opportunity would undermine the proposed price mitigation.

A further consideration is that Load is generally not dispatchable on a 10-minute basis (analogous to the problem of inflexible generating resources discussed earlier). Large commercial customers typically prefer more advance pricing notice in order to have adequate time to adjust their operations, reschedule employees, etc. Moreover, Loads typically need to implement curtailments in blocks of hours and are either incapable or not interested in varying their Demand in response to 10-minute prices. The ISO has endeavored to take these constraints into account in the design of its own Demand Relief and Discretionary Load Curtailment Programs.

The ISO understands that having a price-responsive Demand curve in the real-time market during periods of true supply scarcity would provide an opportunity for the MCP to be set at the "marginal buyer's reservation price" and thus provide an opportunity for a Generator that is always on the margin to earn scarcity rents. The lack of fully price-responsive Demand in the ISO's real-time market will obviously not allow for this type of price determination. However, as the Commission pointed out, "Since bilateral contracts should be the principal means by which generators recover their total costs, generators should be willing to sell any residual real-time energy for any price at or higher than their marginal cost." April 26 Order, 95 FERC at 61,364. Given: (1) the ambiguity of the Order with respect to whether Demand bids can set the MCP price during mitigated hours, (2) the serious gaming opportunity that would arise if the ISO allowed such an approach, (3) the fact that marginal Generation resources will have opportunities to recover their total costs from bilateral contracts, and (4) the many other viable opportunities for real-time Demand price responsiveness, the ISO plans to set the real-time MCP during *all* mitigated hours equal to the highest bid dispatched for a gas-fired Generating Unit at or below that Generating Unit's proxy price.

G. <u>The April 26 Order Fails To Address the Problem of Megawatt Laundering</u>

The April 26 Order recognizes the problem of "megawatt laundering" – the practice of some suppliers of scheduling exports of in-state power in the Day-Ahead market and then re-importing it for sale in the real-time market to avoid mitigated prices – but offers no remedy other than instituting an investigation into public utility sales for resale in the WSCC.

The mitigation measures applied by the Commission thus far and as proposed in the April 26 Order have left opportunities for suppliers to sell at unmitigated prices under circumstances when that supply is most needed (*i.e.*, circumstances where mitigation has been determined to be necessary and appropriate). The mechanics of megawatt laundering illustrate an important case in point. Megawatt laundering does not require the same entity to perform both the export and import components of the export-import cycle. California Generators simply can sell power to marketers at high prices in advance of real-time, and the marketers can in turn offer the power back to California at even higher prices in real-time. Therefore, a price mitigation regime that allows marketers to cost-justify high real-time prices on the basis of high forward power purchase prices would be ineffective at mitigating megawatt laundering (and, accordingly, would be deficient legally).[96]

The simplest and most effective way to foreclose megawatt laundering opportunities is to mitigate all WSCC spot transactions, whether or not they occur within a formal market. As the ISO proposed in its May 7, 2001 comments on the

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[96] As discussed above, it is not clear in the Commission's April 26 Order whether the bids from entities importing Generation (*i.e.*, bids from "resources located outside of California") as well as a marketer's bids are subject to justification and refund. *See* April 26 Order, 95 FERC at 61,359, 61,360. Assuming that all import bids (whether from marketers or others) must be justified, the Commission allows the justification to occur based on "*the prices they paid for power*." *Id*. at 61,360 (emphasis added). The price paid for power can be the result of the last of several intervening transactions or trades for the power. *See id*. at 61,359 (recognizing that marketers often sell energy "numerous times"). Justification based on the cost basis of the last trade provides no price mitigation if the price can be raised by selling and reselling the power prior to bidding it into the ISO's real time market. Moreover, such conduct could be solely the result of the Commission's mitigation rules and would not require any collusion by Generators.

Commission's WSCC-wide Section 206 investigation, the mitigated prices should apply to all bilateral trades in the WSCC region executed in the time period from the day-ahead up to real-time. This would include the ISO's real-time market as well as the out-of-market transactions upon which the ISO has had to rely at various times to obtain Energy that was not otherwise available at mitigated prices and in order to avoid curtailing firm Load.[97] When suppliers no longer have opportunities to sell power at unmitigated prices in the "spot" time frame in the WSCC, there will be no reason to withhold supply (either in the forward market or the early hours of an operating day) to exploit their market power to drive up spot prices further.

H. The Commission Should Modify the Underscheduling Penalty

In the December 15 Order, the Commission established an underscheduling penalty as part of its price mitigation plan. December 15 Order, 93 FERC at 62,002. This action was based on the Commission's finding that the underscheduling problem jeopardized reliable system operations by forcing the ISO to satisfy far more Load in real time than the market was intended to supply (*i.e.,* approximately five percent). *Id*. at 62,002-03. Therefore, the December 15 Order required all Scheduling Coordinators ("SCs") to schedule their Load in the Day-Ahead or Hour-Ahead markets and imposed penalties when actual metered Demand exceeds more than five percent of an SC's scheduled Demand. *Id*. The December 15 Order also established a 10 MW minimum deviation to accommodate smaller entities. *Id*. at 62,003.

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[97] May 7 Comments at 8-11. See also the discussion in section III.C., above.

On February 2, 2001, SoCal Edison and PG&E filed a request for immediate suspension of the underscheduling penalty adopted by the Commission in its December 15 Order.[98] In their filing, SoCal Edison and PG&E acknowledged that the purpose of the penalty was to alleviate the reliance on the ISO's Imbalance Energy market to meet Load. They explained, however, that certain events have made it impossible for them to expand their forward purchases, specifically: (1) that the PX has suspended operating certain markets; and (2) they have experienced credit and supply problems. SoCal Edison and PG&E urged the Commission to recognize that, given these circumstances, the underscheduling penalty cannot provide an incentive to their procurement strategy and instead amounts to an additional tax on their already expensive Energy purchases.

The ISO filed comments supporting the request to suspend the penalty provision.[99] The ISO noted that, in the abstract, the penalty was appropriate to reduce the historical over-reliance on the Imbalance Energy market which has at times satisfied high levels of total system Load. However, the ISO pointed out that the penalty is currently placing an additional burden on SoCal Edison, PG&E, and their ratepayers at a time when they are under extreme financial duress and that the penalty is not having the desired effect of encouraging

[98] Request of Southern California Edison Company and Pacific Gas and Electric Company for Immediate Suspension of Underscheduling Penalty, Docket No. EL01-34-000 (Feb. 2, 2001).

[99] Motion to Intervene and Comments of the California Independent System Operator Corporation, Docket No. EL01-34-000 (Mar. 2, 2001).

forward contracting given the current market situation. Accordingly, the ISO urged temporary suspension of the penalty provision.

On April 6, 2001, the Commission requested additional information related to this issue.[100] Specifically, the Commission sought a quantification of the amount of Load that SoCal Edison and PG&E will serve through forward purchases and the projected amount of Load that will continue to be supplied through the ISO's Imbalance Energy market for each calendar month from April 2001 through September 2001. The ISO filed the requested information on April 23, 2001, indicating its belief that an underscheduling penalty could not possibly be effective under the current circumstances and recommending its suspension through the end of 2001. The ISO offered two justifications. First, absent effective market power mitigation measures, suppliers have little or no incentive to enter forward contracts at just and reasonable rates. Second, given the current financial condition of California's two largest utilities, the State of California has become the only creditworthy buyer in the real-time market and the State agency responsible for these purchases, the CDWR, is acting diligently to procure and schedule Energy on a forward basis. The ISO concluded that to assess a further penalty on the utilities for underscheduling will only increase the

[100] *Southern California Edison Company and Pacific Gas & Electric Company*, 95 FERC ¶ 95 FERC 61,025 (2001).

ultimate cost of Energy to California consumers without furthering any beneficial objective.[101]

If, as the ISO believes absolutely necessary, the Commission mitigates all region-wide spot transactions, it will have provided all sides with an appropriate incentive to forward contract. The problem intended to be addressed by the underscheduling penalty will have been dealt with directly, more efficiently, and in a far superior manner from an operational standpoint. Accordingly, the ISO urges the Commission to act at this time to remove the underscheduling penalty.

I. Linking Mitigation of Unreasonable Wholesale Prices to an RTO Filing Is Illegal

In the April 26 Order, the Commission conditioned its mitigation plan on a submittal by the ISO and the three California IOUs of a new RTO proposal. April 26 Order, 95 FERC at 61,354. So conditioning the right of California ratepayers to just and reasonable wholesale rates is an abuse of the Commission's authority under the Federal Power Act, and the condition must be abandoned.

The Commission has explicitly found that wholesale rates in California had been, and had the potential to continue to be, unjust and unreasonable. November 1 Order, 93 FERC at 61,349-50; December 15 Order 93 FERC at 61,998-99. Under Section 206 of the Federal Power Act, upon such a finding,

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[101] On May 16, 2001, the Commission issued an Order rejecting the ISO's proposed tariff revisions that would have suspended the underscheduling penalty from January 1, 2001 through June 1, 2001. *California Independent System Operator Corporation*, 95 FERC ¶ 61,199 (2001). The Commission stated that it would address the issue of the appropriateness of the underscheduling penalty in Docket No. EL01-34-000 in response to the motion filed by PG&E and SoCal Edison. *Id.*, slip op at 6.

"the Commission shall determine the just and reasonable rate . . . thereafter to be observed and in force, and shall fix the same by order." The Commission's duty under Section 206 is not discretionary. The statute does not provide that the Commission "may" fix a just and reasonable rate; it does not say that the Commission shall provide for a just and reasonable rate if the wholesale purchasers satisfy certain conditions; it says the Commission *shall* fix the just and reasonable rate. The duty is therefore unconditional.

The April 26 Order suggests that, if the ISO or the IOUs do not submit a satisfactory RTO proposal, the Commission will punish ratepayers in California by permitting unjust and unreasonable rates, to the limited extent the April 26 Order's mitigation measures would preclude excessive rates. There is nothing in the Federal Power Act which suggests that the Commission even has the authority even to compel utilities to form an RTO, much less to condition the right to receive just and reasonable rates upon such a requirement. Section 314 of the Federal Power Act specifically sets forth the mechanisms by which the Commission is permitted to enforce its orders. That section does not include among those measures the power to punish consumers by perpetuating unjust or unreasonable rates.

Indeed, allowing such rates to continue would be an impermissible abdication of the Commission's duties. As the Court of Appeals for the District of Columbia Circuit has observed,

> As to matters within its jurisdiction, the Commission has the duty – not the option – to reform rates that by virtue of changed circumstances are no longer just and reasonable.

Louisiana Public Service Com'n v. FERC, 184 F.3d 892, 897 (D.C. Cir. 1999).

The Commission simply cannot allow the persistence of unjust, unreasonable, or discriminatory rates, even with the intent of advancing other policy objectives the Commission considers desirable. *Mid-Tex Elect. Coop., et al., v. FERC*, 773 F.2d 327 (D.C. Cir. 1985); *see also Kansas Cities v. FERC*, 723 F.2d 82, 95 (D.C. Cir. 1983) (holding that to prescribe rates that are known to be unduly discriminatory or preferential is to prescribe rates that are known to be unlawful, which would be a violation of the Commission's responsibilities).

The Commission cannot set aside its fundamental charter in pursuit of the goal of creating an efficient, competitive market for electricity. Federal Power Act rate regulation was provided in the first place precisely because of a market breakdown, much as exists today in California. The Federal Power Act was enacted because the pre-1935 Power Act regime was rampant with market power abuse. *See Gulf States Utilities Co. v. FPC*, 411 U.S. at 758; *see also Federal Power Com'n v. Hope Natural Gas. Co.*, 320 U.S. at 610. It was because of the universal recognition that rates that were the product of the exercise of market power were injurious to consumers and to the economy – it was because such rates were neither just nor reasonable. *Id.*

Regulation, therefore, was intended to emulate the results that could be expected to pertain in a free, workably competitive marketplace, which is precisely what the Commission states it intends by its price mitigation plan. To now tolerate, even in the interest of restructuring, market prices that are the product of the abusive exercise of market power – as the Commission has found

– would be a complete abdication of the very purpose of Commission regulation. It would amount to nothing less than a sanctioning of illegality.

The Commission simply *cannot* is abandon to the market its responsibility to set just and reasonable rates in the face of indications that the market structure that is in place cannot be relied upon to fulfill that statutory requirement. *See Federal Power Com'n v. Texaco, Inc.*, 417 U.S. at 397. Yet this is precisely what the April 26 Order affirms that the Commission would do if the ISO or the IOUs do not submit a satisfactory RTO proposal.

The Commission cannot, consistent with its statutory mandate, use unjust and unreasonable rates as a club to enforce compliance with its orders. The Commission should revise the April 26 Order such that the imposition of any price mitigation is unconditional.

J. It Is Arbitrary and Capricious for the Commission to Set a One-Year Sunset Date for the Mitigation Measures

The Commission's April 26 Order limits the duration of its mitigation plan to one year.[102] In light of the Commission's statutory responsibilities, however, this limitation cannot be justified by the record.

By terminating the mitigation plan, the Commission will return to sole reliance on the market to ensure just and reasonable rates. As discussed above, the Commission may only do so, however, based on a demonstration that the market will produce such rates.[103]

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102 April 26 Order, 95 FERC at 61,364.

103 See the discussion in section III.A , above.

The Commission has no evidence before it to justify a return to market-based rates one year hence. There is absolutely nothing in the record to suggest that the present conditions that the Commission has found require the suspension of unmitigated market-based rate authority will be improved in one year. Certainly, the market conditions that prevailed when the Commission issued its grants of market-based rate authority have fundamentally changed. For example, at the time such authority was granted, capacity available to California's IOUs could be considered uncommitted because California law required it to be sold through the California Power Exchange. As required by the December 15 Order, not only is the California Power Exchange no longer operating, but also the Commission has ordered that the IOUs use all capacity available to them to serve native Load. December 15 Order, 93 FERC at 61,999-62,002. Resources dedicated to native Load must be considered committed, which substantially alters the market analyses on which the Commission based previous orders. More importantly, the Commission itself has subsequently found that market power now exists, and cannot rely upon speculation to support a return to sole reliance on market-based rates. *See Electric Consumers Resource Council v. FERC*, 747 F.2d 1511 (1984).

The only evidence on which the Commission relies for its determination that, one year from the date of its order, it can rely on the market to produce just and reasonable rates is its requirement for Demand response programs and the Governor's projection that new Generation will be online. April 26 Order, 95 FERC at 61,354. But this does not even remotely fulfill the requirements set forth in *Elizabethtown*. At the very least, the Commission would need evidence of the effectiveness of Demand response programs, would have to determine that the new Generation is in place, and would have to evaluate the ownership and location of the new Generation. The Commission cannot now short-circuit satisfaction of a burden that those seeking market based authority must discharge. *See Elizabethtown*, 10 F.3d at 870; *Farmers Union*, 734 F.2d at 1510.

Moreover, the Commission's justification for the termination is irrational. The Commission asserts that terminating the mitigation plan within a year will help ensure that all parties work to achieve the goal of adding Generation and improving market mechanisms. April 26 Order, 95 FERC at 61,364. Generators, however, have no motivation to build sufficient new Generation to eliminate market power concerns when they can be assured that, one year hence, they will again be free to exercise unrestrained market power. In contrast, if they were faced with the knowledge that the mitigation plan will stay in place until adequate Generation is built, Generators have every reason to build. Accordingly, the Commission should revise the April 26 Order to provide that the mitigation plan will remain in place until such time as the Commission's review of the California market demonstrates that a workably competitive environment exists.

IV. CONCLUSION

Wherefore, for the reasons discussed above, the ISO respectfully requests that the Commission take the following actions on clarification or rehearing:

1) Condition the continued use of market-based pricing on the implementation of a comprehensive and effective mitigation approach, such as recommended by the ISO, or return to a cost-based rate regime until it can be demonstrated, with the proponents bearing the burden of proof, that market forces would constrain prices to just and reasonable levels.

2) Remove the limitation that mitigation will only cover sales into the ISO's Imbalance Energy market during System Emergency conditions.

3) Clarify that, under the April 26 Order, out-of-California suppliers (as well as in-state Generators and marketers) must justify bids above the proxy price-based MCP during periods of mitigation.

4) Clarify that, at times when an operationally constrained unit such as a CT is not needed to serve Load or maintain reserves, such a unit shall not set the MCP.

5) Determine, in the event the Commission continues to find that the use of a proxy price methodology is appropriate, that: (1) it is not appropriate to include emissions compliance costs in the calculation and (2) gas prices should reflect the "Bid-week" monthly price from Gas Daily rather than the daily spot price.

6) Expand the mitigation measures to include the ISO's Ancillary Services and Congestion Management markets.

7) Remove the Demand bidding aspects of the April 26 Order and support the existing and ongoing efforts of the ISO, the IOUs and the State authorities to provide for Demand participation in the ISO markets as well as improving the ability of end-use customers to respond to price signals.

8) Prevent the exercise of megawatt laundering by granting the relief proposed by the ISO in its May 7, 2001, comments concerning the WSCC-wide Section 206 investigation.

9) Eliminate the underscheduling penalty.

10) Remove the improper linkage between mitigation measures designed to protect consumers from unlawful rates and the Commission's desire for the ISO and the IOUs to submit an RTO filing.

11) Revise the April 26 Order to provide that the mitigation plan will remain in place until such time as the applicants for relief from those conditions demonstrate, and the Commission is able

reasonably to conclude, that the California energy markets are workably competitive.

Respectfully submitted,

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Dated: May 25, 2001

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in the above-captioned dockets.

Dated at Washington, DC, on this 25th day of May, 2001.

Sean A. Atkins
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