Attachment A

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 OF THE CALIFORNIA AIR RESOURCES BOARD FOR EXPEDITED CONSIDERATION AND FOR LIMITED REHEARING AND CLARIFICATION OR, IN THE ALTERNATIVE, FOR PARTIAL STAY AND TECHNICAL CONFERENCE

PREFACE / LIST OF EXHIBITS

The California Air Resources Board ("ARB") has filed concurrent with this Motion, a Motion to Intervene in the captioned proceedings.

Attached to this Motion, and incorporated herein, are the following:

EXHIBIT 1. Testimony of Michael Scheible, Deputy Executive Director, ARB

EXHIBIT 2. Testimony of David Vidaver, Electricity Market Analyst, California Energy Commission

EXHIBIT 3. Letter to Federal Energy Regulatory Commission from South Coast Air Quality Management District[1]

NATURE OF MOTION

Pursuant to Rules 212 and 713 of the Rules of Practice and Procedure, 18 C.F.R. §§ 385.212 and 385.713, ARB files this Motion for Expedited Consideration and for Limited Rehearing and Clarification or, in the Alternative, for Partial Stay and Technical Conference in response to the Federal Energy Regulatory 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" In re: San Diego Gas & Electric Co. 61 FERC ¶ 61,115 issued April 26, 2001("Order"). In this Motion, ARB argues that:

[1] The attachments to the letter have not been included in the exhibit. The letter and attachments have been posted by FERC in the docket for this proceeding in the RIMS system at Document 2154623.

1. An emissions cost factor should not be included in the calculation of the proxy bid price because it will not result in a valid substitute price that would serve to emulate a competitive marketplace and, therefore, should not be included in a price mechanism intended to reflect the marginal variable cost of producing electricity;

2. The part of the Order requiring the California Independent System Operator ("ISO") to factor in an emissions rate component in the calculation of a proxy bid price cannot be implemented because of vagueness and the multitude of variables inherent to the determination of costs associated with emission rates;

3. The Commission's proxy price mechanism should not include mitigation fees;

4. Including an emissions rate factor in the proxy bid price will result in significant adverse impacts on California's air quality and will both interfere with California's attainment efforts as well as harm California's business community;

5. The tacit approval of the Commission of generators incorporating civil penalties paid as a result of violations of law into their marginal cost calculations to be passed on to electricity consumers not only flies in the face of the stated desire to replicate a competitive marketplace but fosters illegal behavior on the part of generators; and

6. The requirement of a generator to comply with the Commission's must-offer obligation without regard to environmental limitations may expose generators to federal enforcement actions.

ARB has been authorized to state that the California Independent System Operator and the California Electricity Oversight Board support this motion. ARB has also been authorized to state that the California Public Utilities Commission has been made aware of this motion and has not raised any objections or concerns.

ARB, in making these comments, should not be seen as endorsing the overall approach taken by the Federal Energy Regulatory Commission. Our comments are intended only to address the flaws in that portion of the Order that would include emissions costs in the calculation of a proxy bid price.

BACKGROUND

A. Federal Energy Regulatory Commission's Order

On April 26, 2001, the Federal Energy Regulatory Commission ("FERC" or "Commission") issued an order in the captioned proceedings in which the Commission adopted a market monitoring and mitigation plan (the "California Plan") for the California electric wholesale market. Two of the stated goals of the California Plan are to establish: (1) a single market clearing price auction for the real-time market; and (2) a price mitigation for variable capacity in real-time when there is a reserve deficiency of 7.5%[2] or less. Order, slip op. at 2.

The price mitigation mechanism established under the Order is based on (natural gas-fired) generator-supplied data regarding the heat rate and emission rate for each generator unit as well as an allowance for operation and maintenance costs. Order, slip. op. at 15. Under the Order, the ISO is required to use this data to set a theoretical proxy bid price. Ibid.

The order states that the emission rate component is to be calculated with reference to emission costs set by Cantor-Fitzgerald Environmental Brokerage Services. Ibid. This is one of the several brokerage services available in California.

[2] It is our understanding that a Stage 1 emergency is called upon reaching a 7% reserve point.

Ex. 3 at 6. The Order is silent as to which criteria pollutant should be tracked, which market should be used, or how a price for emission rates should be established. It is also not clear why the Cantor-Fitzgerald service was selected.

FERC indicates that the California Plan is designed to mimic a competitive marketplace. Order, slip op. at 8. It was the Commission's determination that the use of an assumed market price relying on inputs such as heat rates and emission costs would emulate the bidding that would occur in a competitive market clearing auction.

FERC has previously included emission costs in a proxy price mechanism used to determine refund obligations for generators from January 2001 to the present. 94 FERC ¶ 61,245, at 61,283 (2001), reh'g pending.[3] It is not clear from FERC's April 26 Order whether FERC intended for the proxy price mechanism adopted in that order to be the same as that used to calculate refunds.

B. The State Implementation Plan

As required by the Clean Air Act ("Act"), 42 U.S.C. §§ 7401 et seq., the Administrator of the United States Environmental Protection Agency ("USEPA") has set national ambient air quality standards for six pollutants including ozone. Based on the amount of these pollutants in the ambient air, portions of the United States were determined to be in attainment or nonattainment of these standards.

[3] See also Notice of Proxy Price for February Wholesale Transactions in the California Wholesale Electric Market issued March 16, 2001;Notice of Proxy Price for March Wholesale Transactions in the California Wholesale Electric Market issued April 16, 2001; Notice of Proxy Price for April Wholesale Transactions in the California Wholesale Electric Market issued May 14, 2001.

Additionally, if an area was determined to be in nonattainment of the ozone standard, a determination of the level (or degree) of nonattainment was also made. States as large and diverse as California have both attainment and nonattainment areas for individual criteria pollutants and with respect to the ozone standard, California has nonattainment areas in all classes of nonattainment, from marginal to extreme.

Each state is required to submit an implementation plan ("SIP") to USEPA demonstrating either how it will remain in attainment in those areas that meet a standard, or how it will reach attainment in those areas determined to be in nonattainment of a standard. 42 USC § 7410. The Act has specific SIP requirements for nonattainment areas. 42 USC § 7502. In addition to these basic requirements, the Act sets further requirements for ozone nonattainment areas. 42 USC §§ 7511 et seq. The Act imposes greater requirements based on the degree of nonattainment of the ozone standard.

The SIP is, in essence, the roadmap for achieving and maintaining attainment of the federal standards. In California, the ARB is the state agency designated as the air pollution control agency for federal law purposes. Cal. Health & Safety Code § 39602. This includes responsibility for the SIP.

C. The California Air Permit Program

The Act sets out several requirements for SIPs for nonattainment areas. One requirement for nonattainment areas is a permit program for the construction and operation of new and modified stationary sources. 42 U.S.C. § 7502 (c)(5). An electrical generating unit would be an example of a stationary source.

One of the conditions for issuance of a permit to construct a new facility may be that a new or modified stationary source obtain emission reduction credits ("ERCs") sufficient to offset the new emissions. 42 U.S.C. § 7503. Both the ratio of required ERCs needed to offset new source emissions (the offset ratio) and the threshold at which offsets are required depend on the level of nonattainment.

California has thirty-five separate air pollution control or air quality management districts. District boundaries are based in large part on air basins; areas having similar geographic and meteorological characteristics. A district may be in attainment of one standard and nonattainment for another.

With regard to ozone, California has districts that range from attainment of the ozone standard to extreme nonattainment.[4] The requirements for offsets vary substantially from district to district based on the degree of nonattainment of the district in which that facility is sited. Within the same district, the requirements for offsets also vary depending on the capacity of the facility to emit pollutants, as well as operational limitations defined by the operator.

The analysis of any facility is based on information supplied by the operator. It is common for an operator to include as part of the project description self-imposed limits on operations, and thus emissions, in order to avoid requirements, such as offsets, that would otherwise be applied. In other words, the quantity of emissions credits required to construct and operate a facility can vary from a large

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[4] Ozone is the product of a photochemical reaction. In the context of stationary sources, it is addressed through control of its precursors including NOx and reactive organic compounds ("ROCs").

number for facilities with high levels of emissions to none at all for small facilities or those with effective emissions controls. In any event, it is important to understand that ERCs must be acquired as part of the permitting process for the construction of each facility. With the exception of the RECLAIM program described below, once a qualifying stationary source is permitted, the number of ERCs it requires to operate is fixed. Thus, while the quantity of ERCs varies considerably from facility to facility, the number and cost of those credits does not vary once a facility is constructed and operational.

In recent months there have been modifications to the operating hour limitations of some generators. Acting pursuant to his authorities under the California Emergency Services Act,[5] Governor Gray Davis has issued Executive Orders[6] that require air districts to allow power generators to operate in excess of limits in their air quality permits and to collect mitigation fees for excess emissions.

D. The RECLAIM Program

ERCs used to offset emissions from new sources should not be confused with the Reclaim Trading Credits ("RTCs") traded in the Regional Clean Air Act Incentives Market ("RECLAIM").[7] The RECLAIM program is limited to the South Coast Air Quality Management District ("SCAQMD"), the only area in the nation

[5] Cal. Gov't Code §§ 8550 et seq.
[6] Executive Orders D-24-01 and D-28-01. These executive orders can be found at www.governor.ca.gov/issues/energy.
[7] Information regarding the RECLAIM program was previously provided to FERC by ARB through testimony of Michael Scheible submitted with Response of the Public Utilities Commission of the State of California to November 1, 2000 Order, and Request for Rehearing as to Issues Which Have Been Finally Determined, filed on November 21, 2000, in Docket Nos. EL00-95-000, EL00-98-000, ELI00-107-000, ER00-3461-000, and ER00-3673-000 (hereinafter "Nov. Test."). The South Coast Air Quality Management has recently provided further information included as Exhibit 3.

designated as extreme nonattainment for the ozone standard. SCAQMD has jurisdiction over only about 20% of the state's generating capacity. Nov. Test. at 4.

ERCs and RTCs are not interchangeable. ERCs are acquired before operations are even started and then become fixed over the life of the project. RTCs, on the other hand, are based on an initial cost-free allocation that will be reduced annually until 2003, upon which the allocations will become constant. The costs associated with the two kinds of credits are not comparable.

In October 1993, the SCAQMD adopted the RECLAIM program as part of its effort to achieve and maintain NOx and SO_x standards required by the Clean Air Act.[8] Ex. 3 at 2. The SCAQMD decided that in lieu of implementing a "command and control" approach to reducing NOx and SO_x emissions from sources greater than four tons per year, it would grant RECLAIM facilities the flexibility to either make the changes necessary to reduce their emissions to designated levels or to acquire additional RTCs on the RECLAIM trading market. Ibid. The SCAQMD is the only California air district that has such a program. Ibid.

Briefly, this is how the RECLAIM system works. Each RECLAIM facility was issued an allocation of RTCs for each year of operation. Ex. 3 at 2. An RTC is a limited right to emit a criteria pollutant (e.g., NO_x) and may be bought, sold or transferred in accordance with RECLAIM rules. Ibid. Allocations started at higher than historic emission levels in 1994, but decrease annually each year through 2003, after which they continue at a constant level. Nov. Test. at 2. RTCs must be used for the year they are issued. Ex. 3 at 2. If not used, they expire. Ibid. A RECLAIM

[8] SCAQMD Regulation XX.

source may choose to install emission control equipment that enables it to operate within its annual allocation, or may exceed its emissions allocation, so long as it acquires sufficient RTCs from other sources. Ibid. A source that emits at lower levels than its allocation may sell its excess RTCs at whatever price the market will bear. Ibid.

Until last year, the price of NO_x RTCs remained relatively stable. Ibid. However, the increased demand for power generation beginning last summer caused a rapid escalation in the price of NO_x RTCs and a near depletion in the availability of credits, causing havoc in the RECLAIM market. Ex. 3 at 3. On January 11, 2001, the SCAQMD staff acted by proposing to remove power generators from the RECLAIM program. Ibid. Less than a week later, Governor Davis declared a state of emergency.[9] Soon thereafter, on February 6, 2001, the SCAQMD Executive Officer issued an executive order suspending the rules for RECLAIM-power-producing facilities to alleviate the emergency as declared by the Governor. Ibid.[10] On May 11, 2001, the SCAQMD formally amended its rules to remove power-producers from RECLAIM. Ibid.

[9] The Governor's proclamation of a State of Emergency can be found at www.governor.ca.gov/issues/energy.
[10] The ISO explained the February changes to FERC in its request for rehearing of the initial refund order. See Application for Rehearing of the California Independent System Operator Corporation, filed April 9, 2001, in EL00-95-026, et al.

ARGUMENT

I. THE PROXY PRICE SHOULD NOT INCLUDE THE COST OF EMISSION CREDITS

ARB understands that in both the Order in which FERC establishes a prospective mitigation plan, and its prior refund orders, FERC is intent upon setting proxy prices that approximate the marginal cost of producing electricity. Order, slip op. at 15, 22; San Diego Gas & Electric, 94 FERC ¶ 61,245, slip op. at 4. It is an error for FERC to include the costs of emissions credits, whether they be ERCs or RTCs, in any proxy price intended to reflect the marginal price of electricity.

A. The Proxy Price Should Not Include the Cost of ERCs

1. ERCs Are Not Variable Costs

FERC has correctly stated that only variable costs should be taken into account in setting the marginal cost of electricity. See San Diego Gas & Electric, 94 FERC ¶ 61,245, slip op. at 4. ERCs, however, are not variable costs. Ex. 1 at 4.

Generators that must obtain ERCs must acquire them at the time of permitting, which is prior to commencement of operations. Ibid. At such time, the owner procures the amount of ERCs needed for the operational life of the facility. Once acquired, they are dedicated to the project for the life of the project and have no impact on operating costs. Unless and until the generator modifies the project, the generator will not incur additional ERC costs during the life of the project.

Costs of ERCs are basically a capital cost incurred when a facility is built. These costs are no different in this respect than other acquisition costs, such as land costs. Thus, they are more in the nature of fixed costs, not variable costs.

2. The Proxy Price Should Not Include ERCs Because Variations in the Cost of ERCs Are Not Related to Efficiency

The goals of the Commission to replicate a competitive market can best be achieved by limiting the calculation of proxy bid prices to inputs that reflect the cost of actual operations. Efficiency and fuel costs do that. ERC costs do not.

The Commission has determined that basing the proxy price on the highest cost of production would encourage new generators to enter the market. San Diego Gas & Electric Co., 94 FERC ¶ 61,245, slip op. at 4. Presumably the greater the inefficiency, the greater the cost. Tying the price to these inefficient facilities inflates that price, making market entry more attractive, hopefully to more efficient, lower cost producers. Even assuming that generators would make long-term capital commitments based on short-term price fluctuations, an assumption the ARB questions,[11] using the costs of ERCs to encourage market entry will not further the Commission's goal.

ERC costs are entirely independent of the generating unit. Where heat rate has a correlation to efficiency, the costs of ERCs do not. Key factors in determining ERC cost, as noted above, depend on the nature of the pollutant and the availability of ERCs for that pollutant in the district where the facility is proposed. The cost of ERCs varies substantially from district to district. Moreover, not all generators must buy ERCs. There are a myriad of factors that are involved in the determination of whether, and to what extent, a generator would be required to obtain ERCs.

[11] Given the short term duration of the Order, which creates the artificial proxy price, ARB questions whether it would be utilized for any capital investment decision.

B. The Proxy Price Should Not Include the Cost of RTCs

In an earlier order, FERC based its proxy price for purposes of refunds on the cost of NOx RTCs in SCAQMD. San Diego Gas & Electric, 94 FERC ¶ 61,245, at 61,863 (2001), reh'g pending. It may be that the intent of the April 26th Order was also to base the proxy price on the cost of such credits. It is improper for FERC to include such costs in the proxy price. Ex. 2 at 3 – 4.

It has never been appropriate for FERC to set a proxy price for electricity for the whole State on the basis of NOx RTC costs in the SCAQMD for two reasons:

- The RECLAIM program is unique to SCAQMD, which has only 20% of California's generators. Nov. Test. at 4. No other air district in California has ever required existing generators to buy emission credits for ongoing operations. Ex. 3 at 1. So, basing a statewide proxy price on the basis of costs paid only in the SCAQMD bears no relation to the marginal cost of electricity elsewhere in California, and therefore creates a significant windfall for generators operating outside that district. Ex. 1 at 4 - 5.
- Even for generators within SCAQMD, it was always improper to assume that they paid for NOx RTC credits since generators have to purchase such credits to operate only after exhausting their free allocation of credits for the year. Ex. 3 at 7. Thus, even within SCAQMD, including the cost of NOx RTC credits creates a windfall for generators that have not exhausted their allowances. Ibid.

It is particularly inappropriate for FERC to set a proxy price for electricity in 2001 and beyond because generators in the SCAQMD no longer buy RTCs for NOx emissions in the RECLAIM program. As explained in detail in SCAQMD's letter to

FERC attached as Exhibit 3, since February 2001, SCAQMD has not required generators to provide RTCs to operate. Ex. 3 at 3. Thus, including the cost of NOx RTC credits in the mechanism used to set the proxy price would not reflect what generators actually pay for emission costs in any district in California.[12]

II. THE PORTION OF THE ORDER CONCERNING HOW EMISSIONS COSTS ARE INCLUDED IN THE PROXY PRICE MUST BE CLARIFIED

The portion of FERC's order pertaining to inclusion of emission costs in the proxy price is too ambiguous for the ISO to implement. The order indicates only that generators are to file with FERC and the ISO the "emission rate for each generating unit" and that "[t]he emission cost will be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services and the emissions rate for the unit." Order, slip op. at 15.

The guidance FERC has provided regarding how emissions costs are to be taken into account in setting the proxy price is inadequate for three reasons.

- First, the Order fails to indicate for which pollutant emission rates are to be provided. ARB assumes FERC probably meant to have the ISO collect only information on NOx emissions.
- Second, if FERC intended for the proxy price to be based on the cost of ERCs, the Order fails to specify which of the many market prices reported by Cantor Fitzgerald Environmental Brokerage Services ("Cantor Fitzgerald") are to be used by the ISO to determine prices. The market indices published by Cantor

[12] Under some circumstances generators in the SCAQMD are now required to pay mitigation fees of $7.50/lb. of NOx emissions. Whether it would be appropriate for FERC to include these mitigation fees in the proxy price is discussed in section III of this Motion.

Fitzgerald at its website include prices for ERCs for several pollutants for several different California ERC markets -- the SCAQMD, the San Diego Air Pollution Control District, Bay Area Air Quality Management District, and the San Joaquin Valley Unified Air Pollution Control District. Ex. 1 at 4. There is a considerable cost disparity among these markets. NOx ERCs in the Bay Area Air Quality Management District were being advertised for $16,000 per ton on May 11, 2001. In the San Diego Air Pollution Control District on the same day, NOx ERCs were being advertised for $104,000 per ton. Should the ISO use the highest price and create a windfall for all other generators at the expense of ratepayers? Should it arbitrarily pick one or average all available data so that the proxy bid price has virtually no resemblance to any market at all?

- Finally, the Order is ambiguous with respect to RTCs. While the Order refers broadly to "emissions costs," implying that it is referring to ERCs, the Order also refers to the proxy price mechanism FERC developed for refund purposes which was based exclusively on the cost of NOx RTCs. San Diego Gas & Electric, 94 FERC ¶ 61,245, at 61,863 (2001), reh'g pending.[13] Did FERC really intend to include ERCs or did it intend to only include RTCs? Did FERC intend to include both?

[13] There is also ambiguity regarding the March 9 order. In that order, FERC set the proxy price by using emissions rates for NOx and the "average January NOx allowance costs from the Southern California Air Quality Management District NOx Auction of $22.50 as reported by Cantor Fitzgerald Environmental Brokerage Services." San Diego Gas & Electric, 94 FERC ¶ 61,245, slip op. at 4-5 (emphasis added). FERC proxy notices for February, March, and April also referred to the "Southern California Air Quality Management District." Order, slip op. at 4; February Notice at 2; and March Notice at 2; April Notice at 2. Since there is no such Air Quality Management District, ARB assumes that FERC intended to refer to the South Coast Air Quality Management District.

The difficulties that the ISO faces in complying with the Order, as written, are overwhelming. FERC must clarify the Order.

III. THE PROXY PRICE SHOULD NOT INCLUDE MITIGATION FEES

Although FERC does not mention mitigation fees in the Order, the reality of the situation in California is that in recent months some generators have begun to pay mitigation fees.[14] Some might argue that such mitigation fees should be included in the proxy price. ARB strongly objects to inclusion of mitigation fees in the proxy price. ARB acknowledges, however, that if the proxy price a generator would get is not adequate to cover costs, including mitigation costs, the generator should be able to use such mitigation fees to justify receiving an as-bid price.

A. Air Districts Have Begun to Impose Mitigation Fees

As noted above, Governor Gray Davis, by Executive Order, authorized existing electrical generation facilities to operate in excess of allowed hours of operations to maximize available electricity generating capacity upon payment of a mitigation fee. Ex. 1 at 3. This fee would only be paid when, and only to the extent that, a facility exceeded its permitted operating levels. Ibid.

These fees are not penalties. Districts are to use these fees to fund mitigation efforts, emission reduction programs, to reduce the impacts of the excess emissions resulting from electrical generating operations exceeding permitted hours of operations. Ibid. Since these permits are issued locally, the amount of mitigation fees are determined by the permitting agency and the generating facility. Ibid.

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[14] In the Order FERC does refer to emissions penalties." Order, slip op. at 15. It is not clear whether FERC intended for this term to include mitigation fees.

Because of this, mitigation fees vary from air district to air district throughout the state.

These mitigation fees are not the same as the mitigation fees paid by generators in the SCAQMD who exhaust their allocations of RTC credits for the year. In SCAQMD, once generators have exhausted their allocation, they are no longer required to buy RECLAIM credits, but are required to pay mitigation fees of $7.50 per pound of NOx. Ex. 3 at 3. Mitigation fees are not paid in "real-time," only quarterly. Ex. 3 at 5. Under the current reporting system, the District and ISO cannot identify in advance of the quarterly reconciliation when particular generators will exhaust their allocations and begin to incur liability for mitigation fees. Ibid.

B. Mitigation Fees Should Not Be Included in the Proxy Price

As further explained below, ARB believes that the ISO should not be required to include mitigation fees in proxy prices for several reasons:

- FERC's objective in using a marginal cost pricing mechanism is to use a proxy price that "best replicates the results that would be produced in a competitive market." Order, slip op. at 22. Apparently, FERC believes it is necessary to use this mechanism to induce economic efficiency. Whatever the merits of FERC's approach may be for assuring optimal market performance for most generator costs, however, this approach simply has no application to mitigation fees. Unlike other variable generator costs, generators do not control whether or to what extent they must pay mitigation fees. Collection of mitigation fees is within the control of the air districts.

Thus, including mitigation fees in the proxy price will not induce economically efficient behavior by generators. See generally Ex. 1 at 4 - 5.

- Not only would inclusion of mitigation fees provide no gain in economic efficiency, it would provide incentives to generators that run directly counter to the objectives of the Clean Air Act which air districts implement. In particular, including mitigation fees in the proxy price would provide incentives to generators to run their units with high emissions levels and avoid installation of air pollution control technology which would reduce these emissions. Ex. 2 at 4 – 5; Ex. 3 at 7.
- Including mitigation fees in the proxy price would put air districts in the unfortunate position of having to choose between collecting the mitigation fees they need to protect air quality and protecting ratepayer interests that would be adversely affected by having these costs reflected in a proxy price. Ex. 2 at 6. In fact, the amount collected in mitigation fees would be far less than the additional profits earned by generators who would be able to earn the proxy price regardless of whether they were the generators that paid the mitigation fees. Ibid; Ex. 1 at 5 - 6. This may well result in great pressure upon the air districts to forgo collection of the mitigation fees they need to be able to protect air quality or having the entities other than the generators assume the payment obligation of generators to protect ratepayer interests. Ex. 2 at 6.
- Finally, FERC should not require the ISO to include mitigation fees because it would be very difficult for the ISO to establish proxy prices that include

mitigation fees. To administer such a system, the ISO would have to have a detailed understanding of the arrangements each air district has made with each generator for payment of mitigation fees and whether the conditions for payment had been met.

C. Generators Who Incur Mitigation Fees Should Be Permitted to Recover Their Costs

Although mitigation fees should not be included in proxy prices, ARB recognizes that under some circumstances, generators should be entitled to recover mitigation fees. Unless generators who face the obligation to pay those fees know that the fees can be recovered, they may be reluctant to operate their facilities if the proxy price does not include those potential costs. ARB recommends that generators should be permitted to bid in excess of the proxy price and later substantiate that they should be compensated for mitigation fees. Accord, Ex. 2 at 6 - 7.

IV. INCLUDING EMISSIONS COSTS IN THE PROXY PRICE WILL HAVE AN ADVERSE IMPACT ON THE MARKET FOR EMISSION CREDITS AND ON AIR QUALITY AND WILL THUS BURDEN BUSINESSES AND COMMUNITIES

A. Impact on the Market for Emission Credits

1. Market for ERCs

If emission credit prices are used to calculate proxy prices, generators will have an incentive to deliberately bid up the price of such credits in order to assure a higher proxy price. Ex. 2 at 5; Ex. 3 at 6.

Including ERCs in the proxy price serves to shift the economic burden of a generator's emissions from the generator to other businesses competing for ERCs of the same pollutant. Businesses in the same air basin as a generator must use the same ERC inventory to obtain offsets for their businesses as the generator uses. At today's electricity wholesale electricity prices, generators can afford to pay for increased ERC costs and may benefit from them to the extent that they increase the proxy price. Other businesses, however, will be placed at a competitive disadvantage in their markets because they have no assurances that they will be able to pass on these costs to their customers. If they are unable to pass through these costs, they will be forced to absorb them, or lose market share. In either event, the increased ERC costs will have economic impacts on other businesses that are likely to have ripple effects throughout the local economies of each air district.

2. **Market for RTCs**

Since FERC tied the proxy price for refund purposes to the price of NOx RTC credits, there has been some incentive to manipulate the price of these credits to affect the proxy price. Thus, it is not surprising that in its letter to FERC, SCAQMD indicates that it has recently observed some transactions in the RECLAIM market that strongly suggest that market manipulation of NOx RTC prices by generators is already occurring. Ex. 3 at 6.

SCAQMD is very concerned about possible manipulation of the price of NOx RTC credits, since it has recent knowledge of the adverse impact that sharp increases in the price of RTC credits can have. Ex. 3 at 2 – 3, 6. Such sharp increases in the price of RTCs caused havoc in the RECLAIM market, particularly for the several hundred non-power producing industry businesses that could not install pollution controls and could not compete with the power producers for the RTCs they needed for compliance. Ex. 3 at 2 – 3. Unlike power generators, these businesses had not experienced any significant increase in what they can charge for goods and services, and therefore they could not just pass on increased costs. Ex. 3 at 3.

B. Impact on Air Quality

ARB is also concerned that including emissions costs in the proxy price may affect the behavior of generators in a way that could be detrimental to air quality. By including emissions costs in the proxy price, FERC is giving generators a powerful incentive to operate units with high emissions rates since operating such units would lead to a higher proxy price that all of the generator's other units can charge. Ex. 1 at 5; Ex. 2 at 4 – 5.[15] Moreover, generators would also have a powerful incentive to request longer operating hours for their units with the highest emissions rates. Ibid. Air districts are currently compelled to grant requests for longer operating hours pursuant to the Governor's Executive Orders D-24-01 and D-28-01.

Finally, generators are likely to resist installation of more effective emissions control technologies because installation would reduce emissions rates and hence could reduce proxy prices. Ex. 3 at 7. Where the RECLAIM program was designed to send a price signal that control technologies should be installed and will be cost effective, the FERC inclusion of emission costs in the proxy price turns this incentive on its head. It pays a bonus to all generation units proportional to the highest emissions of the marginal unit. As long as emission costs serve to increase a generator's proxy bid price, what incentive would a generator have to reduce

[15] ARB recognizes that generators may not be in a position to choose which units to operate when the State is in a Stage 3 emergency and all available power is needed to avert blackouts. FERC's price mitigation plan also applies, however, during Stage 1 and 2 emergencies when reserve margins are greater.

emissions? If anything, the Order should at least devise a formula where the generator is not penalized for installing control equipment.

V. THE COMMISSION'S ALLOWANCE OF EMISSION PENALTIES AS A MARGINAL COST COMPONENT IS TANTAMOUNT TO CONDONING THE VIOLATION OF LAW

The ARB is very concerned with the Commission's discussion regarding the inclusion of "emission penalties" as part of a generator's bid. Order, slip op. at 15. ARB hopes that FERC did not intend to include civil penalties for emissions violations as "emissions penalties." Penalties paid as a result of the violation of federal, state or local regulations cannot be considered as simply a cost of doing business. To force the ratepayers of California to in effect indemnify generators against their illegal activities is anything but just and reasonable. The ARB strongly urges FERC to affirm that it does not in any way condone the violation of air quality law and will not permit generators to recover civil penalties as part of a generator's above-market bid.

VI. THE COMMISSION'S CONCLUSION THAT THE STATE HAS COMPLETE DISCRETION TO ALLOW GENERATORS TO OPERATE OUTSIDE ENVIRONMENTAL LIMITATIONS IS INCORRECT

In the April 26th Order, the Commission provided that "no generator will be required to run in violation of its certificate or applicable law," but the Order also refused to exempt gas-fired generators from the must-offer obligation because of environmental limitations. Order, slip op. at 12. The Commission states that whether these facilities can run outside environmental limitations is within the control of the state. Ibid. This is not entirely correct. Once the USEPA approved the California SIP, the measures that California agreed to implement as part of its attainment demonstration became federally enforceable. Any action taken by California that would relax a SIP measure would affect state enforcement only. Such measures remain federally enforceable despite the state action. This is why the ARB has been working closely with the USEPA to ensure that the emergency measures California has been taking do not expose generators to enforcement actions. If generators ignore environmental limits, those generators may very well be subject to federal enforcement.

CONCLUSION

For the foregoing reasons, the ARB believes that the Commission must act on an expedited basis to correct its proxy formula and remove the portions related to emissions costs. The prices cited by the Commission in the Cantor Fitzgerald Index are not part of the marginal cost of electricity because they represent either capital costs (in the case of ERCs) or no longer apply (as in the case of RTCs). Moreover, under the current energy emergency in California, the varying types and myriad rates for mitigation fees throughout the state make them unsuitable proxies for calculating a single market-clearing price for all generators. Any scheme to substitute mitigation fees for emissions credits would bear little relation to any generator's actual emission costs and would be impossible for the ISO to implement.

In addition, including the Commission's proxy emissions rate factor would send the wrong message to electricity generators in California because it would provide a powerful incentive to run relatively dirty units before cleaner ones and potentially delay installation of pollution control equipment. These incentives, as well as the apparent willingness of the Commission to incorporate civil penalties into their marginal cost calculations, would complicate the efforts of federal and state regulators to balance the needs of emergency power with protection of the environment.

The ARB understands that many parties will be seeking rehearing on the mitigation measures proposed in the Order including the appropriateness of the use of the proxy formula. The ARB is not seeking to preclude full consideration of these issues. However, the ARB does believe that the Commission must act immediately to remove, or at least stay, the requirement that the ISO include emissions costs in the calculation of the proxy price.[16]

The ARB respectfully requests that the Commission grant the motion for expedited consideration and:

1. Immediately issue an order indicating that the ISO should not include emissions costs in the proxy price; or, in the alternative.

2. Immediately issue an order staying the effectiveness of the portion of the order concerning including emissions costs in the proxy price and convene a technical conference so that the issues raised may be thoroughly explored.

[16] ARB notes that AES Southland ("AES") has also addressed the emissions cost component of the proxy price in a recent filing in this docket. See Comments of AES Southland, filed May 9, 2001, FERC RIMS Document Number 2151589. AES indicates that FERC's order "fails to recognize how the complex credit and control system operates" (p. 3) and asks the

EXHIBIT 1

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 if Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council	)	Docket No. EL01-68-000

PREPARED DIRECT TESTIMONY OF MICHAEL SCHEIBLE, DEPUTY EXECUTIVE OFFICER, CALIFORNIA AIR RESOURCES BOARD

Kathleen Walsh
General Counsel
George T. Poppic, Jr.
Staff Counsel
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

Dated: May 16, 2001

PREPARED DIRECT TESTIMONY OF MICHAEL H. SCHEIBLE

Q. Please state your name and business address.

A. My name is Michael H. Scheible. My business address is 1001 I Street, Sacramento, California, 95812.

Q. By whom are you employed and in what capacity?

A. I am employed by the California Air Resources Board ("ARB") as the Deputy Executive Officer.

Q. Please describe your professional qualifications.

A. I have worked for the ARB for 27 years in a wide variety of positions. Currently my responsibilities include supervision of the ARB staff responsible for energy issues including electricity. I worked extensively as the ARB's lead person on the development of the RECLAIM program. I have a Bachelor of Science degree in Chemical Engineering, and a Master of Science degree in Air Pollution Control Engineering.

Q. Have you previously filed testimony with the Federal Energy Regulatory Commission ("FERC")?

A. Yes. I filed testimony with FERC in an earlier phase of this proceeding that was included with the Response of the Public Utilities Commission of the State of California to November 1, 2000 Order, and Request for Rehearing as to Issues Which Have Been Finally Determined, filed on November 21, 2000, in Docket Nos. EL00-95-000, EL00-98-000, EL100-107-000, ER00-3461-000, and ER00-3673-000.

Q. What was the purpose of your prior testimony in this proceeding?

A. The purpose of my testimony was to address the extent to which the costs of RECLAIM Trading Credits (RTCs) impacted electricity generation costs and electricity prices this year.

Q. Have there been significant changes to the RECLAIM program since you last provided testimony to FERC?

A. Yes, there have been significant changes. A major change is that power plants will no longer be part of a NOx RTC market, at least until 2004. As I will discuss later, this change very much impacts recent FERC actions.

Q. What is the purpose of your testimony at this time?

A. The purpose of my testimony in this proceeding is to explain ARB's concerns regarding FERC's April 26, 2001, order, 95 FERC ¶ 61,115. In particular, ARB is concerned that FERC does not understand that emission credit costs are not a variable cost of production and hence should not be included in the proxy price. Furthermore, including emissions costs in the proxy price could have a significant adverse impact on air regulatory programs and air quality, as well as the cost that Californians must pay for power.

Q. Have there been other significant changes in the regulation of air emissions from power plants since you last provided testimony to FERC?

A. Yes. One significant change is that soon after the Governor declared a state of emergency in the State due to an inadequate supply of electricity he issued Executive Order D-24-01 which pertains to extension of operating hours at existing power plants. As a result of this Executive Order, California air districts have been entering into agreements with generators to allow additional operating hours in return for payment of mitigation fees to be used to fund emission reduction programs for pollutants of concern.

Q. Have you read FERC's order of April 26, 2001, 95 FERC ¶ 61,115? What does it say concerning how emissions costs are to be included in the proxy price?

A. Yes, I have read the order. It does not provide a great deal of detail about how or why emissions costs are to be included in the proxy price. The order indicates that generators are to file with FERC and the ISO the "emission rate for each generating unit." It further states that "The emission cost will be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services and the emissions rate for the unit."

Q. Are you familiar with Cantor Fitzgerald Environmental Brokerage Service ("Cantor Fitzgerald")?

A. Yes, this service is one of many sources that my staff occasionally uses to determine the prices that new or expanded sources might pay for emission reduction credits.

Q. What types of emissions cost information is provided by Cantor Fitzgerald?

A. The market indices published by Cantor Fitzgerald at its website include prices for emission reduction credits for several pollutants for several different California emission reduction credit markets -- the South Coast AQMD, the San Diego Air Pollution Control District ("San Diego APCD"), Bay Area Air Quality Management District ("Bay Area AQMD"), and the San Joaquin Valley Unified Air Pollution Control District ("San Joaquin APCD").

Q. Do you believe that it is reasonable for FERC to include emissions costs based on information such as that available from Cantor Fitzgerald and plant emission rates in the proxy price of electricity that it establishes for the coming year in the April 26 order?

A. No, I do not believe this is reasonable. In its orders, FERC indicates that it is putting emissions costs into the proxy price because they are a component of variable costs and that these costs can be reasonably represented through information available from Cantor Fitzgerald. This indicates that FERC did not anticipate the changes to the RECLAIM program. Furthermore, with the exception of NOx credits for RECLAIM (NOx RTCs), all costs for emissions reductions credits are fixed costs expended at the time of permitting. These costs do not change regardless of how much generators actually produce. With the changes in RECLAIM, some power generators will be required to pay a set fee per pound of excess NOx emissions as a mitigation fee. (Some other units in other locations will also face similar fees in return for allowing increased hours of operation.) This is not a variable cost of operation set by a competitive market, but more akin to a fee for excess emissions not otherwise allowed by the rules affecting the source. In my view, it is not appropriate for FERC to establish a mechanism where all generators in the market would receive a higher payment because some sources must pay such mitigation fees.

Q. Do you believe that including emissions costs would have an adverse impact on air quality?

A. Yes I do. Including emissions costs in proxy costs will give generators an incentive to operate their units with the highest emissions rates to secure a high proxy price. This would be counter to our efforts to produce electricity with the lowest emission mix of plants.

Q. Could the inclusion of emissions costs in the proxy price have a significant impact on that price?

A. Yes. Emissions rates vary tremendously from the cleanest unit to the most highly polluting. Older, poorly controlled peaking units can emit NOx at 5 pounds per megawatt-hour. Some of these units often operate during peak demand periods. (Average NOx emissions are expected to be in the order of 1 pound per megawatt-hour during peak periods this summer.) Including these "costs" in the proxy price as is contemplated in the FERC order could increase the price of all power by $37.50 per megawatt-hour (5 pounds NOx/megawatt-hour x $7.50/pound NOx price potentially paid by some generators in the South Coast AQMD.)

Q. Do you think FERC should change the portion of its April 26, 2001, order in which it addresses including emissions costs in setting proxy prices?

A. FERC should change the order to make it clear that emissions costs will not be included in proxy prices. As I have explained, it is inappropriate to include the costs of NOx RTCs, emission credits, or mitigation fees since they are not variable costs. Moreover, including such costs will have an adverse impact on air regulatory programs and air quality.

Q. Do you think that FERC should include the mitigation fees paid by some generators in the proxy price?

A. No, I do not believe it is appropriate to include mitigation fees in the proxy price. Such fees are applied selectively to generators that exceed some condition of their permit. These are not true variable costs faced by most generators.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION PURSUANT TO RULE 2005

I, Michael H. Scheible, declare, on oath, that I caused the foregoing testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

Michael H. Scheible

Michael H. Scheible

EXHIBIT 2

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

PREPARED DIRECT TESTIMONY OF DAVID VIDAVER,
ELECTRICITY MARKET ANALYST,
CALIFORNIA ENERGY COMMISSION

Dated: May 23, 2001

Q. Please state your name and business address.

A. My name is David Vidaver. My business address is 1516 Ninth Street, Sacramento, CA 95814.

Q. By whom are you employed and in what capacity?

A. I am employed by the California Energy Commission ("Energy Commission") as an electricity market analyst in the System Assessment and Facility Siting Division.

Q. Please describe your professional qualifications.

A. I have worked for the Energy Commission for five years in a wide variety of positions. Currently my responsibilities include analysis of the electricity markets for the state of California. I have degrees from the University of California, Berkeley and the University of California, Davis.

Q. Have you previously filed testimony with the Federal Energy Regulatory Commission ("FERC")?

A. No.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to supplement the testimony of the California Air Resources Board ("ARB") to explain, from an electricity market perspective, how: (1) including emissions costs in a proxy price of electricity set to reflect the market clearing price is inappropriate; (2) including emissions costs in the proxy price is likely to affect the behavior of generators in a way that could adversely affect the RECLAIM market; (3) including emissions costs in the proxy price may adversely affect air quality; and (4) selecting an alternative way of handling emissions costs is preferable to FERC's approach.

Q. Have you read FERC's orders concerning proxy prices that are dated April 26, 2001, 95 FERC ¶ 61,115, and March 9, 2001, 94 FERC ¶ 61,245?

A. Yes I have.

Q. What does FERC say concerning what the proxy price is supposed to reflect?
A. FERC states that the proxy price is to be based on variable costs and is supposed to reflect a competitive market clearing price.

Q. How does FERC intend to establish the emissions cost component of the proxy price?
A. While it is not clear from the April 26, 2001 order how FERC intends to establish the emissions cost component of the proxy price, it appears that FERC intends to adopt the methodology it developed to determine the proxy price in the March 9, 2001 order. In this order, FERC indicated that emissions costs should be based on the emissions rate for NOx and the cost of credits for NOx emissions in the RECLAIM market.

Q. Does FERC's methodology reflect a complete and up-to-date understanding of the RECLAIM market?
A. Apparently, it does not. FERC recently sent a letter to the South Coast Air Quality Management District ("South Coast AQMD") requesting information concerning RECLAIM. The South Coast AQMD's response is being submitted concurrently with the submission of this testimony.

Q. Is it appropriate for FERC to include the costs of NOx credits in the RECLAIM market in the proxy price of electricity?
A. No, it is not appropriate for FERC to include the costs of NOx credits in the RECLAIM market in the proxy price. FERC's decisions indicate that it is including the costs of NOx credits in the proxy price because they are a component of variable costs. Until the beginning of 2001 in one geographic region in California (the LA Basin) this was the case. Currently, however, as South Coast AQMD explains in its response to FERC's letter, there have been significant changes to the RECLAIM program, including key elements that make changes retroactive to January 11, 2001.

Generators are no longer required to purchase RECLAIM credits. Generators may generate up to their initial allocations plus net purchases as of January 11, 2001. All generation up to this limit involves fixed costs, not variable costs. For generators that exceed this limit, costs become variable, as any additional generation results in payment of mitigation fees to South Coast AQMD of $7.50 per pound of NOx. Though these fees are variable based on kwh generated, it is critical to note they are incurred only by the individual unit exceeding its RTC holdings.

Q. If FERC persists in using the costs for NOx paid in the RECLAIM market in its proxy price, or switches to including mitigation fees in the proxy price paid to all units, might there be an adverse impact on air quality?

A. Yes there might be an adverse impact upon air quality for several reasons:

- Inclusion of the cost of tradable credits or mitigation fees in the proxy price encourages the exhaustion of emission allowances. It is only when a unit's proxy price can incorporate this cost that the operation of said unit enables the manipulation of the market clearing price. The dirtier the unit whose proxy price determines the price paid for all generators, the greater the reward to all the units in a generator's portfolio. Once a generator has exhausted its permitted hours or emission allowance, inclusion of the cost of emissions credits or mitigation fees in the proxy price encourages the continued operation of dirty units. As the proxy price is applied during Stage 1, 2 and 3 emergencies – hours when capacity is increasingly scarce – there is an incentive to operate one or more units with high emission factors so that one of them might determine the price paid to output from other units in a generator's portfolio, and, in fact, all participants in the market. The operation of units with high emissions factors ensures a higher market clearing price and therefore greater returns to the other units in the portfolio. Even if an emergency is not anticipated, it is possible that an incentive remains to operate a dirty unit, in order to ensure a higher market clearing price in the event that an emergency occurs.

The new Rule 2009 adopted for RECLAIM on May 11, 2001 makes it more difficult to achieve this outcome. However, in periods of increasing electricity resource scarcity (during stage 1, 2, and 3 emergencies), generation owners can increase the likelihood of a dirty unit setting the proxy price paid to all by bringing cleaner units down for maintenance or unplanned outages.

- Inclusion of the cost of emissions credits or mitigation fees in the proxy price discourages the timely adoption of SCR or other emission controls on the dirtiest units in a generator's portfolio.[1] As the price applies during Stage 1, 2 and 3 emergencies – hours when capacity is scarce – units with high emission factors will operate and determine the price paid to output from other units in a generator's portfolio. Failing to control emissions ensures a higher market clearing price and therefore greater returns to the other units in the portfolio. Even if the increase in the marginal cost of operating a dirty unit that results from failing to apply emission controls is large enough to "price the unit out of the market" during some non-emergency hours, the foregone profit during these hours will be small (assuming the unit would have been "barely inframarginal" had emission controls been applied) and often more than offset by additional profits accruing to the remaining units in the portfolio due to a higher market clearing price.

Q. If FERC includes costs for NOx credits in the RECLAIM market in its proxy price, what impact might this have on the RECLAIM market?

A. If the current market price of RECLAIM credits were included in the proxy price generators would have an incentive to increase prices in the credit market however this could be accomplished. Even the revised RECLAIM rules do not prohibit generators from purchasing RTCs, rather, they are precluded from applying purchases made after April 1, 2001, to emissions generated after first quarter 2001.

[1] Implementation of compliance plans is not enforceable under federal law and may not result in mandatory installation of controls.

Q. Do you think FERC should change the way it has approached emissions costs in setting proxy prices?

A. FERC should take emissions costs out of proxy prices. Inclusion of the cost of mitigation fees in the proxy price paid to all generators increases the cost of meeting air quality standards to irrationally and unnecessarily high levels. The revenue from the imposition of mitigation fees is intended to fund emission reduction programs to offset the emissions of generators beyond existing and heretofore accepted limits in the specific air basins where the emissions occur. When the cost of mitigation fees is included in the market clearing price, however, the cost to ratepayers exceeds the amount paid by the generator, often by a hundred fold, whenever the mitigation fee paid by the marginal unit is greater than zero. For example, a 50MW combustion turbine in the South Coast AQMD with an emission rate of 5 lbs./MWh pays 50 MW x 5 lbs./MWh x \$7.50 = \$1875/hour in fees, but the cost of electricity to ratepayers in that hour would be 10,000 MW x 5 x \$7.50 = \$375,000, if 10,000 MW were provided in the markets in which the proxy price was applicable. It would be far more efficient for state entities charged with protecting ratepayer and taxpayer interests to pay these mitigation fees directly to the air districts rather than include them in the proxy price paid to all generators.

Q. Should generators be allowed to recover the costs of mitigation fees?

A. If the proxy price calculated on the basis of the natural gas and operations and maintenance costs alone is not adequate for a generator to recover the cost of mitigation fees paid for operating beyond permit limits, then generators should be allowed to recover mitigation fees. Paying less than marginal cost eliminates incentives to operate; we propose to eliminate windfall profits from government policies designed to protect and promote air quality, <u>not</u> to penalize generators who are more efficient.

In the April 26, 2001, order, FERC suggests that if generators have to pay "emissions penalties" greater than that assumed in the proxy, they can bid a price higher than the proxy price and can be paid the price bid provided the generator can substantiate that the emissions penalties have been incurred. It is not clear what FERC means when it uses the term "emissions penalties," but to the extent to which FERC means "mitigation fees," permitting such fees to be recovered as bid is the correct approach.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION PURSUANT TO RULE 2005

I, David Vidaver, declare, on oath, that I caused the foregoing testimony to be prepared; that the answers appearing therein are true to the best of my knowledge and belief; and that if asked the questions appearing therein, my answers would, under oath, be the same.

David Vidaver

EXHIBIT 3

South Coast
Air Quality Management District
21865 E. Copley Drive, Diamond Bar, CA 91765-4182
(909) 396-2000 · http://www.aqmd.gov

Office of the Executive Officer
Barry R. Wallerstein, D.Env.
909.396.2100, fax 909.396.3340

May 16, 2001

Daniel Larcamp
Director, Office of Markets, Tariffs, & Rates
FEDERAL ENERGY REGULATORY COMMISSION
Washington D.C. 20426

Re: San Diego Gas & Electric Company v. Sellers of Energy,
FERC Docket No. EL00-95-017 - Response to Your May 9, 2001 Letter

Dear Mr. Larcamp:

I am pleased to respond to your letter dated May 9, 2001 requesting additional information on nitrogen oxide (NOx) emission costs for electric generators regulated by the South Coast Air Quality Management District (SCAQMD).[1] The SCAQMD is concerned about the appropriateness of including NOx emission costs that are unique to the SCAQMD in any statewide "proxy market clearing price" for electricity. I understand that this issue is particularly important, because it not only relates to the March 9, 2001 Order issued by the Federal Energy Regulatory Commission (FERC) relating to refunds, but also to FERC's April 26, 2001 Order establishing a mitigation and monitoring plan for wholesale electricity prices in the State of California.

Your request for information is timely, because recently on May 11 our Governing Board amended SCAQMD regulations (RECLAIM) to provide significant relief to electric generators in response to the ongoing electricity crisis. Since these rule amendments, in effect, codified the SCAQMD Executive Orders that you are requesting information about, I will also be discussing them in the context of my responses to your questions. Before addressing your questions, I believe it will be helpful to provide you with some background information on the RECLAIM

[1] Cantor Fitzgerald and your letter refer to us as the Southern California Air Quality Management District. However, there is no entity known as the Southern California AQMD. Our jurisdiction is much more limited, and does not cover all of Southern California. The SCAQMD includes all of Orange County, and the non-desert portions of Los Angeles, Riverside, and San Bernardino Counties, as well as the Palm Springs/Indio area. The South Coast AQMD includes 12,000 square miles and 15 million people.

program, which created this ability, which only exists in the SCAQMD and not elsewhere in California, to trade NOx emission credits or RTCs (RECLAIM Trading Credits). Thereafter, I will provide answers to your specific questions. Finally, I will provide some additional comments about the significance of the information you requested.

<u>RECLAIM Program Description</u>

The Regional Clean Air Incentives Market (RECLAIM) program was adopted by the SCAQMD Governing Board in October 1993 and the program was implemented in 1994. It applies only within the SCAQMD and has no applicability in other parts of California. The program was developed with widespread industry and electrical utility support and represents a significant departure from traditional command-and-control regulations. Under command-and-control, facilities would be required to purchase NOx emission reduction credits (ERCs) at the time of construction to offset all NOx emissions from their future intended operation. As a result, these purchases of ERCs would represent a sunk cost and further purchases would not be required as a result of the operation.

On the other hand, facilities under the RECLAIM program were issued a declining annual emissions allocation based on their past maximum production levels. Allocations are issued in the form of RECLAIM Trading Credits (RTCs), which represent pounds of NOx allowed to be emitted. Each RTC is valid for a period of one year and may be traded or sold. All of the medium and larger sized fossil fuel fired power plants in the District were in the RECLAIM program until the program was changed as explained below. Today, several hundred other industrial facilities remain in the program. There are presently no power generators over 50 MW participating in the program. A RECLAIM source may choose to install emission control equipment that enables it to operate within its allocation, or may exceed its emissions allocation, so long as it acquires sufficient RTCs from other sources. (Likewise, a source that emits at lower levels than its allocation may sell the excess at whatever price the market will bear to facilities needing RTCs.) RTCs must be used for the year they are issued. If not used, they expire. Most, if not all power plant owners chose to purchase RTCs instead of adding control equipment. As a result, power plant owners were able to defer until now the costs of installing advanced pollution control equipment such as selective catalytic reduction (SCR) on their large power generation boilers.[2]

From the start of RECLAIM, the price of NOx RTCs had remained relatively stable until the summer of 2000, at which time an increased demand for power generation resulted in the electric power industry purchasing inordinately large quantities of RTCs. This action resulted in

[2] Under command-and-control, they would have been required to install this control equipment years ago in the mid-1990's.

the near depletion of available RTCs and caused the price of NOx RTCs for Compliance Year 2000 to jump from approximately $4,284 per ton traded in 1999 to approximately $45,609 per ton traded during 2000. This sharp rise in RTC prices caused havoc in the RECLAIM market, particularly to those non-power-producing industry businesses that could not install pollution controls and could not compete with the power producers for the RTCs they needed for compliance. (Power producers could pass on these increased costs.) Even for those facilities that could install air pollution control equipment, the inevitable time required for permitting and installation of controls forced them into the wildly escalating RTC market.

As a result, on January 11, 2001, SCAQMD staff proposed rule amendments for the RECLAIM program which would eliminate the need for power-producing facilities to purchase RTCs in order to comply with their emissions allocations. On February 6, 2001, I issued SCAQMD Executive Order #01-02, which immediately allowed large power-producing facilities (over 50 MW) to exceed their emissions allocation by paying a mitigation fee of $7.50 per pound of NOx emitted in excess of their allocation. (This order has now been replaced by SCAQMD Executive Order #01-03, making a technical correction.) The Executive Order was issued pursuant to SCAQMD Rule 118, authorizing suspension of SCAQMD rules to alleviate an emergency as declared by the Governor. Since then, the Order has been extended in 10-day increments as allowed by Rule 118. The relief provided by the Executive Order has now been formally codified by the SCAQMD Board's amendment of RECLAIM on May 11, 2001. The effect of the Executive Order and the new RECLAIM amendments was to decouple compliance costs of power producers from the RTC prices paid by other facilities that remain in RECLAIM.

I will now address the specific questions you have raised in your letter.

<u>Responses to FERC Questions</u>

Q-1. Please explain how the provisions of the Executive Order apply to and what are the practical implications for electric generators. Please list the generating units to which this Order applies. What are the cost implications of deducting RTCs from the facility's allocations for the subsequent compliance year 2003?

A. As indicated earlier in this letter, SCAQMD Executive Order #01-03 allowed the power plant operators to exceed their RECLAIM NOx allocations and provided a mechanism to pay a mitigation fee of $7.50 per pound of NOx instead of purchasing RTCs to cover any exceedances. In effect, power generators were no longer constrained from operation by their emissions allocation and the cost of exceeding their allocation is now fixed at a price well below the then market price of RTCs. (FERC's Notice of Proxy Price for February referred to a February RTC market price of over $40.00 per lb.)

SCAQMD Executive Order #01-03 was available to all RECLAIM power plant operators with 50 or more megawatts of generation who wished to take advantage of it. To date, four separate facilities have sought use of the Executive Order. These power plant facilities are listed in Table I below. Since RECLAIM provides an allocation for the entire facility, rather than on a generating unit by unit basis, the Executive Order applied to all the generating units within the facility. Consequently, a third party could not determine a specific mitigation fee for a specific generating unit under the RECLAIM program.

Under the RECLAIM rules prior to the May 11 amendment, facilities that exceeded their allocation had those excess emissions deducted from their next year's allocation in order to make the environment whole. Under SCAQMD Executive Order #01-03 and the amended RECLAIM rules, power-producing facilities may further delay this deduction by two years, at which time it is anticipated that full control equipment will be in place, and the demand and supply of electricity will come into balance. In addition, the mitigation fees will be used by the SCAQMD to generate NOx emission reductions that will be credited to offset any deductions from the power-producing facilities. As a result, the SCAQMD sees no significant additional costs stemming from the subsequent year deductions. Indeed, the SCAQMD has already identified emission reduction projects that will create enough NOx reductions to fully compensate for power plant NOx emission exceedances that occurred in the first quarter of 2001.

Q-2. Over what period has the suspension of rules for RECLAIM-power-producing facilities having the capacity to produce 50 MW or more been in effect?

A. The suspension of rules for RECLAIM-power-producing facilities has been in effect since February 6, 2001 and the substantive relief provided by the suspension continues to remain in effect as a result of the May 11, 2001 RECLAIM rule amendments. Under the May 11 RECLAIM amendments, the power producers are removed from the RECLAIM RTC market through 2003 and possibly longer. If they emit in excess of their allocation, they need only pay a $7.50 per lb. mitigation fee. The SCAQMD is required by the RECLAIM rules to use that money to obtain NOx emission reductions from mobile sources, such as cleaner marine engines. Existing large power producers are now prohibited from using RTCs acquired after January 11, 2001 to compensate for excess emissions occurring after April 1, 2001. They now pay mitigation fees instead, which are not a tradable instrument.

Q-3. Facility operators are to pay the District a mitigation fee at the time of the quarterly or annual report required by Rule 2004. Have these payments and reports been made by electric generators? If so, please provide the Commission a copy of the reports and records of the payments. If the payments and reports have not been received, when do you expect them to be made? Please provide the Commission a copy of the reports and records of the payments when you receive them.

A. Facility operators need only pay a mitigation fee if their actual reported NOx emissions exceeds their annual allocation. Pursuant to SCAQMD Rule 2004, facility operators are provided 30 days after the first three compliance quarters and 60 days after the last quarter to reconcile their emissions with their annual allocation. By the end of the reconciliation period, facilities pay a mitigation fee if there are emission exceedances. As a result, mitigation fees are not paid at the time of exceedance, and therefore may not be determined on a real time basis. Thus, there is no way for a third party to determine when mitigation fees may need to be paid. In addition, no mitigation fees are paid for emissions that are covered by the facility's allocation. Further, if mitigation fees are paid at all, the amount is unique to each facility and is not tradable. Therefore, mitigation fees should not be incorporated as part of a proxy market-clearing price.

During the reconciliation period following the RECLAIM compliance quarter ending March 31, 2001, four power-producing facilities reported NOx emissions in excess of their RTC holdings and paid mitigation fees. As a result, these facilities submitted a mitigation fee in the amount of $7.50 per pound of excess NOx emissions. Table I below summarizes these mitigation payments. (Some RECLAIM power producers chose not to use the Executive Order and chose to remain in the RECLAIM market, an option which they no longer have.)

TABLE I

Company Name	Payment ($)
AES Huntington Beach	2,044,290
AES Alamitos	2,382,375
AES Redondo Beach	989,333
Reliant Energy - Etiwanda	1,184,160
Total	6,600,158

Attached to this letter as Exhibit A are copies of the records of payments made by these facilities as well as their quarterly reports. Please note that these quarterly reports only reflect the facility's reported emissions in that particular quarter. Additional information such as the facility's allocation and cumulative emissions would be required to verify the amount of exceedance. In addition, it should be noted that facility emission reports are subject to field audit by SCAQMD compliance staff and may require revision. The above payments were based on the facility's calculation of emissions in excess of its allocations.

Q-4. The Executive Order requires facilities to provide written notification 24 hours prior to generating excess emissions. Please provide the Commission copies of these notifications.

A. The SCAQMD staff has been in numerous meetings with the major power producers and knew that they would be using the Executive Order. As a result, staff waived the written notice requirements. Under the rule amendments adopted on May 11, 2001, advance notice is not required.

Q-5. The Commission is relying on one emissions broker for information on NOx emission allowance costs. Are there other brokers? If so, please identify them.

A. Before answering this question, the SCAQMD must first point out that since the issuance of SCAQMD Executive Order #01-03 on February 6, 2001, any reported brokerage prices for NOx RTCs would not reflect the cost of RTCs for RECLAIM-power-producing facilities. As you are aware, these costs are now capped at $7.50 per pound of excess NOx emissions by both the Order and the amended RECLAIM rules.

As to your specific question, there are several brokers participating in the RECLAIM trading market. Similar to Cantor Fitzgerald, most brokers serve as a third party assisting both buyers and sellers in negotiating RTC prices. Many of these brokers have a vested interest in higher RTC prices, since their commissions are based on these prices. Another major participant in the RTC market is ACE. This firm periodically holds an auction where potential buyers and seller input their desired prices into the system. Based on the bidding prices, the ACE system creates a single "market price." Sellers who bid at "market price" or lower and buyers who bid at "market price" or higher will be able to participate at the market price. This process is different from the method used by Cantor Fitzgerald and other brokers who serve as intermediary in the direct price negotiation between two parties. A list of the brokers, both active and non-active, that have been participating in the RECLAIM market is also attached as Exhibit B for your information.

<u>General Comments and Suggestion for a Technical Conference</u>

Based on the above information, I believe that you will conclude that the inclusion of emission costs, particularly as suggested using SCAQMD-specific NOx RTC prices as reported by Cantor Fitzgerald, is inappropriate in setting state-wide market-clearing prices for electricity. The use of NOx RTC prices as input for a market clearing price would inevitably lead to potential upward manipulation of NOx RTC prices, thereby potentially undoing the SCAQMD's work in separating out the power-producing facilities from RECLAIM. The SCAQMD has recently observed situations in which power producers have bought RTCs at prices greatly exceeding market prices from out-of-state companies that had purchased RTCs that same day at market prices. Also, the inclusion of emissions costs in the market-clearing price would undermine the SCAQMD's program by encouraging the use of dirtier equipment in an attempt to maintain a high market-clearing price for all units. Inclusion of emissions costs could even provide an incentive for facilities to delay installing needed controls in order to keep their emissions high, resulting in higher mitigation fees and higher proxy prices. Further, we understand that the proxy prices will be allowed for all power producers, even for those that are operating within their allocations, which cost them nothing.

The SCAQMD's Governing Board is extremely concerned that NOx emission costs should not be used to inappropriately calculate higher prices for power in California and to create incentives for more pollution. However, SCAQMD has acted expeditiously to alleviate the power crisis by amending its rules to allow power producers to exceed otherwise applicable emission limits upon compliance with specific conditions. SCAQMD would be pleased to meet in a technical conference or other appropriate forum with FERC representatives to discuss this matter further. Should you have any questions, please call me at (909) 396-2100

Sincerely,

Barry R. Wallerstein

Barry R. Wallerstein, D.Env.
Executive Officer

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cc: Michael P. Kenny, Executive Officer, California Air Resources Board
Jack P. Broadbent, Director, Air Division, EPA Region IX