APPENDIX A

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation, California Electricity Oversight Board, Public Utilities Commission of the State of California,	)	
Complainants,	)	Docket No. EL02- -000
v.	)	
Pacific Gas and Electric Company,	)	
Respondents.	)	

NOTICE OF COMPLAINT

(, 2001)

Take notice that on November 13, 2001, the California Independent System Operator Corporation (the "ISO"), the California Electricity Oversight Board, and the Public Utilities Commission of the State of California submitted a complaint pursuant to Section 206 of the Federal Power Act, 16 U.S.C. § 824e, against Pacific Gas and Electric Company ("PG&E") alleging that certain rates, referred to as the Fixed Option Payments, payable by the ISO under certain reliability must run ("RMR") contracts between the ISO and respondent are unjust and unreasonable.

Complainants allege that the currently effective Fixed Option Payments were set by a series of settlements in 1999 and 2000, that covered most RMR units, including those owned by PG&E. Complainants, along with the major California investor-owned utilities, including PG&E, sought to lower the cost of the Fixed Option Payment in Docket No. ER98-495-000, *et al*. In an initial decision in that proceeding, issued June 7, 2000, the Presiding Administrative Law Judge adopted the "net incremental cost" method for calculating the Fixed Option Payment. Claimants assert that the same method, applied to the respondents' RMR units, would yield Fixed Option Payments lower than those currently in affect. Complainants ask that the Commission institute an investigation, set a refund date of January 12, 2002, and defer further action pending its decision on exceptions in Docket No. ER98-495-000, *et al*.

Copies of the complaint were served on respondents and on other interested parties.

Any person desiring to be heard or to protest such filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214). All such motions or protests must be filed on or before ________, 2001. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Answers to this complaint shall be due on or before _____________, 2001. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room. This filing may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance). Comments and protests may be filed electronically via the internet in lieu of paper. *See*, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site at http://www.ferc.fed.us/efi/doorbell.htm.

David P. Boergers,
Secretary

APPENDIX B

I. Persons Designated for Service

The following persons are designated to receive service pursuant to 18 C.F.R. § 385.2010:

For The California Independent System Operator Corporation:

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II. Section 385.206(b)(9)

The complainants have not initiated formal or informal dispute resolution procedures with regards to the rates the Commission is requested to investigate in this complaint. The complainants believe that, until the Commission rules on the pending exceptions in Docket No. ER98-495-000, the current rate uncertainty will make it unlikely that dispute resolution procedures would successfully resolve the rates in dispute. Complainants are, however, willing to engage in such discussions once the Commission has established a refund effective date in this proceeding and ruled on exceptions in Docket No. ER98-495-000.

APPENDIX C

Condition 1 Units Fixed Option Payment

Unit	Owner	Fixed Option Payment Factor (FOPF)	Fixed Option Payment (FOP)
Humboldt Bay	Pacific Gas & Electric Co.	50%	$ 5,680,041
Helms	Pacific Gas & Electric Co.	50%	$ 52,924,301
San Joaquin	Pacific Gas & Electric Co.	20%	$ 4,682,220

Condition 2 Units Fixed Option Payment

Unit	Owner	Annual Fixed Revenue Requirement (AFRR)
Hunter's Point (Condition 2)	Pacific Gas & Electric Co.	$ 23,670,895

APPENDIX D

Letter Dated September 14, 2001 to Commission

(copy of letter will be inserted)

APPENDIX E

**DECLARATION OF
Robert C. Kott**

My name is Robert C. Kott. I am the Manager of Reliability Contracts in the Contracts Department of the California Independent System Operator ("ISO").

I received my bachelor's degree in Electrical and Electronics Engineering from California State University, Sacramento in 1987 and my masters degree in business administration in 1995 with a concentration in Finance completed in 2000 from Pepperdine University. I am a Registered Professional Engineer in Electrical Engineering in the State of California.

Upon graduating from college, I accepted a position at the Los Angeles Department of Water and Power ("LADWP"). While with LADWP, I held a number of positions including Planning Engineer, Project Manager in the Generation Maintenance Department, Transmission Design Engineer, and Manager of Large Customer Contracts. I joined the ISO in May 2001, as a contractor, working on the creation of Generation Maintenance Standards to carry out the Governor's D-23-01 directive. I assumed my current position as Manager of Reliability Contracts in the ISO's Contracts Department in August of 2001.

I have been asked to consider whether the currently effective Fixed Option Payments payable under the RMR Contract[1] applicable to the RMR Facilities owned by Pacific Gas and Electric Company ("PG&E"), exceed the amount that would be payable under the "net

[1] Capitalized terms not otherwise defined have the meanings provided in the ISO tariff.

incremental cost" method advocated by the Responsible Utilities[2], the California Agencies[3] and the ISO, and adopted by the Presiding Administrative Law Judge in FERC Docket No. ER98-495-000. As described below, I believe the answer is yes.

The PG&E Condition 1 units that have been re-designated by and are currently under contract with the ISO for 2002 as RMR units, together with the stipulated Annual Fixed Revenue Requirement ("AFRR") and current Fixed Option Payment ("FOP"), are as follows:

Unit(s)	AFRR	FOP
Humboldt 1	$ 5,696,826	$ 2,848,413
Humboldt 2	$ 5,500,558	$ 2,750,279
Humboldt CT2	$ 64,175	$ 32,087
Humboldt CT3	$ 98,523	$ 49,262
San Joaquin	$ 23,411,098	$ 4,682,220
Helms	$105,848,601	$52,924,300
Total	$140,619,781	$63,286,561

"Net incremental cost" is a method used to estimate the costs imposed on an Owner as a result of entering into an RMR Contract with the ISO. These costs exclude those costs that could be attributed to not being able to exercise local market power. The testimony of Dr. Joe D. Pace on behalf of PG&E in Docket No. ER98-495-000 identified four categories of such costs: (1) costs of administering the contract, (2) costs of keeping the plant operational during short periods when it would have been shut down if not for its RMR obligations, (3) net going-forward costs of units that, absent the contract, would be shut down, and (4) opportunity costs of having to generate to meet RMR reliability requirements, rather than buy, in the real-time market.[4]

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2 The Responsible Utilities are the Participating Transmission Owners, including PG&E, San Diego Gas and Electric Company and Southern California Edison Company.

3 The California Agencies are the California Public Utilities Commission and the Electricity Oversight Board.

4 Exhibit No. PGE-1 in Docket No. ER98-495-000 at 15-16.

I have considered each of these costs as applicable to the PG&E units that have been designated as Condition 1 RMR units for 2002. I'll refer to these units collectively as the PG&E RMR Units. Note that the Hunters Point Units are Condition 2 units and are paid 100 percent of their annual fixed revenue requirements and have been excluded from this analysis.

My analysis makes use of information from a declaration by Laura M Douglas, Senior Regulatory Analyst in the Policy and Strategy Development Group of the Interconnection Services Department of PG&E, which is attached as Appendix E to a complaint filed on November 2, 2001 by the ISO, the California Electricity Oversight Board (the "EOB"), the Public Utilities Commission of the State of California (the "CPUC"), PG&E, San Diego Gas and Electric Company ("SDG&E") and Southern California Edison Company ("Edison") regarding currently effective Fixed Option Payments payable under the RMR Contract applicable to the RMR Facilities owned by Owners other then PG&E ("Declaration of Laura M. Douglas"). In addition, my analysis makes use of information from testimony submitted on behalf of PG&E in Docket ER98-495-000.

Administrative Costs:

A calculation of the PG&E administrative costs for administering six RMR contracts is set forth in the Declaration of Laura M. Douglas. Ms. Douglas calculates these costs at approximately $582,000 annually to cover the cost of the three employees assigned to administration of their RMR Contracts for most of 2001.

These costs do not appear to include legal and management labor costs related to RMR regulatory filings and ISO RMR processes. However, presumably similar costs would be incurred in any alternative market-power mitigation measures. Similarly, the costs do not include setup costs for establishing RMR settlement and billing functions. The Declaration of Laura M. Douglas estimates these costs at $1.4 million. However, PG&E has already received, between April 1998 and today, significant revenues for its RMR units above payments based on the net incremental cost method. Therefore, it is fair to conclude that PG&E already recovered its setup costs.

<u>Costs of Keeping a Unit Operational for Short Periods</u>: A non-RMR generation owner may desire to shut down an RMR unit during periods when the owner expects the savings from shutdown to exceed the net profit from market participation. The RMR Contract, because it requires that the unit be available at all times for ISO dispatch, would preclude the owner from shutting down its RMR unit. The cost of keeping the unit operational for this period of time results in a cost to the RMR Owner. In Docket ER98-495-000, Mr. Livingston analyzed on behalf of PG&E whether the owner of the units covered by the analysis would have realized more revenues from uneconomic fossil units than the savings the owner would realize by reducing staffing during a seasonal shutdown during the period from November 1998 through April 1999. Mr. Livingston's analysis concluded that the revenues would have exceeded savings.[5]

The fossil PG&E RMR units at Humboldt Bay are the same type of units as those analyzed by Mr. Livingston and thus it is likely that an analysis of RMR units at Humboldt Bay would demonstrate similarly that revenues from operation would exceed savings from a short term shutdown. The hydro PG&E RMR units (San Joaquin River) are more economic to operate

[5] Exhibit No. PGE-13 in Docket No. ER98-495-000 at 5.

than the fossil units analyzed by Mr. Livingston, so there is even less likelihood of significant savings from shutting down these plants for a short period of time.

The pumped storage PG&E RMR units (Helms Facility) are economically viable throughout the year and the likelihood of significant savings from shutting down these plants for a short period of time is negligible. As Mr. Livingston states, the only savings for seasonal closures possible would be the temporary reduction in the number of assistant control operators and less experienced maintenance personnel[6]. These costs savings would likely negligible.

Costs of Operating and Maintaining Unprofitable Units: In Docket ER98-495-000, Dr. Pace stated on behalf of PG&E that, "For units that are not economically viable and would likely shut down permanently but for the RMR obligation, the incremental cost properly attributable to the RMR obligation is the net cost of staying open and available to respond to ISO calls. In this instance, the Fixed Option Payment will have to cover all going-forward costs of operating as an RMR unit not recompensed by other contract payments, minus any net revenues that can be earned in the market by supplying energy and ancillary services when it is economical to do so."[7]

The Declaration of Laura M. Douglas provides that "In light of the prices that have prevailed in California wholesale markets since the spring of 2000, including prices that have prevailed since the implementation of the price mitigation measures adopted by FERC in its orders on April 26 and June 19, 2001, in Docket No. EL00-95-000, there is no reasonable basis to believe that any of the RMR units in PG&E's service territory would have shut down absent

[6] Exhibit No. PGE-13 in Docket No. ER98-495-000 at 8.

[7] Exhibit PGE-1 in Docket No. ER98-495-000 at 7.

the RMR obligation." The ISO agrees with this statement and would include PG&E RMR units in this assumption. Moreover, PG&E has had the option to convert its current Condition 1 RMR units to Condition 2 RMR units if it considered that on a yearly basis, the units were not economically viable. The fact that PG&E has not chosen to convert the units at issue herein to Condition 2 RMR units is further evidence that the units are economically viable.

Opportunity Costs: These are the costs incurred by the RMR Owner when the owner has a day-ahead commitment to sell, and could buy in the real-time market rather than generate and thereby save the difference between the real-time price and its own variable costs. The RMR Contract limits this opportunity by requiring the unit to generate at the level specified in the RMR dispatch notice. The RMR variable cost for the San Joaquin River is very small, on the order of $1.00/MWh. Comparing this to the 2000 average annual NP 15 real-time price of $119/MWh for all hours in the day and the 2000 average annual NP 15 real-time price of $89/MWh calculated for hours ending 0000 through 0600 results in no opportunity cost because the difference is negative. The opportunity cost for the Humboldt Facility is also estimated to be non existent. Based on PG&E RMR invoices for the Humboldt Facility in 2000, the average Humboldt RMR variable cost was $89.36/MWh which is below the average NP15 price of $119/MWh and similar to the average NP 15 price in 2000 during low load hours between 0000 and 0600 of $89/MWh.

Based on PG&E RMR invoices for the Helms Facility in 2000, the Helms average RMR annual variable cost for 2000 was $140/MWh. Using the difference between the average RMR annual variable cost and the average NP-15 real-time price previously mentioned results in an estimated opportunity cost of $690,000[8].

I acknowledge that recently real-time wholesale prices have decreased significantly from 2000 levels. However, this fact should not significantly change my conclusions. First, much of the reduction in wholesale real time prices can be attributed to reduced fuel costs that would result in a decrease in the variable costs of the PG&E fossil RMR units. Moreover, since the opportunity cost for Helms should be based on the ratio of prices in peak hours to prices in off-peak hours, the fact that wholesale real time electricity prices are reduced overall would not automatically affect the opportunity costs for Helms, unless the ratio of prices in peak hours to prices in off-peak hours changes.

In addition, changes in the market rules make the scenario of substantial opportunity costs even less likely to eventuate. Under Amendment No. 29 to the ISO Tariff, filed on May 2, 2000 and effective September 1, 2000, the ISO implemented settlement of the real-time energy market on a ten-minute basis. This change allowed the ISO to make the 10-minute dispatches coincident with the 10-minute settlements thereby requiring the Scheduling Coordinators to respond immediately to the ISO dispatch. Thus, an "uninstructed negative deviation" (i.e., a deviation in real-time from the final hour-ahead schedule not resulting from an ISO dispatch to decrement the unit's output) are charged the ISO's 10-minute incremental energy price, which cannot be less than, and is likely to be higher than, the decremental price.

Similarly, changes adopted in Amendment No. 30 filed September 2000 and accepted by the Commission on December 15, 2000 allocate the costs of "Out-of-Market" energy to

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[8] This calculation is based on Helm's 2000 RMR requirement.

Scheduling Coordinators in proportion to their respective net deviations.[9] Again, the result is to discourage, and diminish the potential profitability of, the "buy-rather-than-run" stratagem hypothesized above.

Further, under Amendment No. 33 to the ISO tariff, filed and effective December 8, 2000, the costs from accepting bids above the ISO's Market Clearing Price (as determined pursuant to the Commission's orders in Docket Nos. EL00-95-000, et al.) are allocated to Scheduling Coordinators with net negative deviations. In effect, then, the owner failing to generate at the level provided in its final hour-ahead schedule (allowing for netting of incremental and decremental deviations in the same Scheduling Coordinator portfolio) is charged for its proportional share of those costs. To the extent that its negative deviation exceeds its accepted decremental bid, that owner is buying the most expensive energy purchased by the ISO for the relevant settlement period.

Additionally, Amendment No. 33 put in place a penalty applicable to Participating Generators that refuse to operate in response to an ISO Dispatch instruction during a System Emergency or when the ISO is acting to avoid an imminent or threatened System Emergency. Each PG&E is a Participating Generator. If non-compliant, PG&E would be charged an amount equal to twice the highest price the ISO paid for energy for each hour in which its generating unit failed to respond. In addition, if, during that hour, the ISO curtailed Load to manage a System Emergency other than Load that has not been designated by agreement or regulation as

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9 A net deviation is the result of netting a Scheduling Coordinator's portfolio on a 10-minute basis of incremental and decremental deviations. If there is congestion, then the deviations are netted by region.

interruptible, PG&E would pay an additional penalty of $1,000/MWh for the energy that it failed to deliver.

Finally, the ISO's Settlement and Billing Protocol, Appendix C, Section C.2.2.3. now allocates a "Deviation Replacement Reserve Charge" on the basis of net negative deviations in any hour. This change compounds the effects described above.

Taken together, these changes make it unlikely that PG&E would now incur significant opportunity costs of the type described in previous testimony.

Offsetting Benefits: There are certain offsetting benefits to the owner created by the RMR Contract. For example, the owner can make market sales at certain hours when the unit would not, absent the contract, be running because of low demand (and prices) in previous and subsequent hours. In order to keep this analysis simple I have forgone estimating these benefits. Excluding these benefits increases the total incremental cost of this analysis making the analysis more conservative.

Total Net Incremental Costs:

The Total Net Incremental Cost determined based on the discussion above with regards to the applicable PG&E RMR units is up to $1,272,000 per year as indicated in the table below versus a Fixed Option Payment for the three facilities of $63,286,561.

Total Net Incremental Cost ($1000 per year)

Facility	Admin Cost	Keeping Unit Operational Cost	Unprofitable Unit Cost	Opportunity Cost	Total
Helms	-	0	0	$690	$690
Humboldt	-	0	0	0	
San Joaquin	-	0	0	0	
Total	$582	0	0	$690	$1,272

Thus the estimated total opportunity cost is approximately 2% of the current Fixed Option Payment for the Condition 1 PG&E RMR units. This is much less than the current Fixed Option Payment for these facilities, and less than the proposed 2002 rates filed by PG&E.

I certify under penalty of perjury that the foregoing is true and correct to the best of my knowledge, information, and belief.

Robert C. Kott

November 9, 2001

APPENDIX F

<u>TESTIMONY AND EXHIBITS INCORPORATED BY REFERENCE</u>

In addition to the ISO's RMR contracts with PG&E, the following exhibits from prior proceedings are incorporated by reference, as are any other exhibits or testimony referred to in this joint complaint.

<u>Docket No. ER98-495-000</u>

Exhibit Nos. PGE-1, 3, 5, 6, 7-11, 13, 15-16

<u>Docket No. ER98-496-000</u>

Exhibit No. SD-19

<u>Docket No. ER98-496-006</u>

Exhibit Nos. SD-2, 7, 13, 15-17

<u>Docket No. EL02-15-000</u>

Appendix E (Declaration of Laura Douglas)

CERTIFICATE OF SERVICE

I hereby certify that on this 13th day of November, 2001, I have served copies of the foregoing joint complaint by instantaneous electronic delivery and hand delivery of Federal Express on counsel for each of the respondents as shown below:

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