UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

JOINT COMPLAINT

By this complaint, filed pursuant to Section 206 of the Federal Power Act, 16 U.S.C. § 824e, and to Rule 206 of the Commission's Rules of Practice and Procedure, 18 C.F.R.§ 385.206, the California Independent System Operator Corporation (the "ISO"), the California Electricity Oversight Board (the "EOB"), and the Public Utilities Commission of the State of California (the "CPUC"), jointly request that the Commission institute proceedings to investigate certain rates -- the "Fixed Option Payments" -- payable by the ISO under certain "reliability must-run" ("RMR") contracts between the ISO and Pacific Gas and Electric Company ("PG&E"), the respondent listed in the caption above. As described more fully below, those rates exceed just and reasonable levels and are inequitable to customers. Because the issue of how properly to calculate the Fixed Option Payment under the RMR contracts is currently pending before the Commission on exceptions in Docket Nos. ER98-495-000, *et al.*, the

Commission should set a refund effective date of sixty days from the date of this filing (January 12, 2002) and defer further action herein until it has ruled on the exceptions in those dockets.[1]

I. NOTICES AND COMMUNICATIONS

The persons designated to receive service under 18 C.F.R. § 385.2010 are listed in Appendix B, as is certain information required by 18 C.F.R. § 385.206(b).

II. INTRODUCTION AND SUMMARY

The RMR contracts were initially approved by the Commission in conjunction with the restructuring of the California electricity market as a means of mitigating the localized market power that would otherwise accrue to the owners or others who control the dispatch of certain generating units. Those units, because of their location and the configuration of the transmission system, must operate at certain times to maintain the reliability of the transmission grid controlled by the ISO and could exercise market power absent the RMR contract. Broadly speaking, the contracts require that the owners of such units, PG&E in this proceeding, generate energy (or provide ancillary services) at those times, and in such amounts, as the ISO may designate in order to preserve local reliability or to manage intra-zonal congestion. The terms of the contracts currently in effect, other than certain rates and operating characteristics that are unit-specific, are substantially the same for all RMR units, and were adopted in a multiparty settlement filed in April 1999 and approved by the Commission the following month.[2] That

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1 A draft notice of this filing, suitable for publication in the Federal Register, is attached as Appendix A hereto.

2 California Independent System Operator Corp., 87 FERC ¶ 61,250 (1999).

settlement left open how to determine the Fixed Option Payment, a rate that varies with unit availability rather than with actual output and that is stated as a percentage of the unit's Annual Fixed Revenue Requirements ("AFRR"). [3]

In a series of further, owner-specific settlements approved by the Commission in the second half of 1999 and the first half of 2000, the owners of RMR units, including PG&E, agreed upon the level of Fixed Option Payments for the period beginning June 1999 for all RMR units except those owned by Southern Energy (now Mirant) Delta, LLC and Southern Energy (now Mirant) Potrero, LLC. The parties to the settlements retained their rights under Sections 205 or 206, as applicable, to seek adjustment of the Fixed Option Payments effective on or after January 1, 2002.

In an initial decision issued in June 2000 in Docket No. ER98-495-000, *et al.*, the Presiding Judge adopted the "net incremental cost" method to calculate the Fixed Option Payment for Southern's units.[4] In general terms, that method would calculate the Fixed Option Payment to make the owner whole for the costs, including opportunity costs, imposed upon the owner as a result of its obligations under the RMR contract. The initial decision rejected competing theories proposed by Southern and adopted, as reasonable, the calculations by PG&E[5]

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3 The term "Fixed Option Payment" does not appear in the body of the RMR contracts themselves, but rather in Article II.B.3 of the April 1999 settlement adopting those contracts. The applicable contract term is "Fixed Option Payment Factor," which is simply a percentage representing all or a specific portion of a given generating unit's Annual Fixed Revenue Requirement.

4 Pacific Gas and Electric Co., 91 FERC ¶ 63,008 (2000).

5 Alone among the various parties to the RMR contracts, PG&E stands in the anomalous position of being both (a) the owner of various RMR units who is entitled to receive payments for maintaining the availability of those units; and (b) the utility, as the transmission owner, from whose rates those payments must be made. Focusing on its interests as a utility, PG&E cooperated on the side of Complainants herein and the other major California investor-owned utilities in Docket Nos. ER98-495-000, *et al*. in seeking to lower the cost of the Fixed Option Payment to the owners of RMR units, even though PG&E was itself the owner of several such units. Indeed, PG&E is a co-complainant in a similar case to this one that was just filed against the other owners of RMR units in California.

implementing the net incremental cost method. The initial decision is pending before the Commission on exceptions.

The Fixed Option Payments currently in effect under the owner-specific settlements described above, including the settlement with PG&E, exceed the levels allowable under the net incremental cost method. To the extent Fixed Option Payments under the settlement with PG&E actually place PG&E in a better position than it would be in if it lacked localized market power and were not subject to an RMR contract, those rates are manifestly unjust and unreasonable. The Commission should, therefore, institute a proceeding to investigate those rates pursuant to Section 206 and, pursuant to Section 206 (b), establish a refund effective date of sixty days from the date of this filing (January 12, 2002), in order to assure maximum protection to affected customers. As a matter of administrative efficiency, however, the Commission should hold this proceeding in abeyance pending its decision in Docket Nos. ER98-495-000, *et al*., so that its decision there can provide guidance for the parties and the designated administrative law judge in adjusting the Fixed Option Payment.

III. PARTIES

A. Complainants

The ISO is a not-for-profit public benefit corporation organized under the laws of the State of California with its principal place of business at 151 Blue Ravine Road, Folsom, California. Under California law, as well as the orders of this Commission, the ISO is responsible for the reliable operation of the transmission system it controls (the "ISO Controlled

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(See the Joint Complaint in Docket EL02-15-000, filed on November 2, 2001.) However, because PG&E is also the owner of RMR units, the complainants herein are compelled to seek the same relief against PG&E in that capacity that they, together with PG&E, sought against the other California RMR owners in Docket EL02-15-000.

Grid"), which includes the transmission facilities owned by PG&E, Southern California Edison ("SCE"), San Diego Gas & Electric Company ("SDG&E") and the City of Vernon, California, respectively. The ISO is also the Control Area Operator for the ISO Controlled Grid and other areas of California that constitute the ISO Control Area. In order to operate the ISO Controlled Grid reliably and to satisfy its obligations as Control Area Operator, the ISO uses RMR contracts to meet local reliability needs or manage intra-zonal congestion. The ISO is party to six[6] RMR contracts with PG&E.

The EOB was created as part of California's comprehensive electricity restructuring legislation. The Board's statutory responsibilities include the oversight of the ISO, the energy and ancillary services markets operated by the ISO, and the reliability of the ISO-controlled grid. Its principal offices are at 770 L Street, Sacramento, California.

The CPUC is an agency established by the Constitution of the State of California and charged with the responsibility for regulating electric corporations within the State of California. It has a statutory mandate to represent the interests of electric consumers throughout California in proceedings before FERC. Its principal offices are at 505 Van Ness Avenue, San Francisco, California.

B. Respondent

PG&E is a California corporation with its principal place of business at 77 Beale Street, San Francisco, California. PG&E owns and operates the Helms power plant at Fresno, California; units 1, 2, Mobile 2 and Mobile 3 of the Humboldt Bay power plant at Trinity,

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[6] Two of the contracts not mentioned herein, FMC and Kings River Watershed, will not be under contract in 2002. FMC was a Condition 2 unit, which expired on September 29, 2001, due to an expired lease and Kings River was not re-designated as RMR for 2002.

California; and the Kerckhoff 1 and 2, Crane Valley, San Joaquin 1A, 2 and 3, and AG Wishon units of the San Joaquin River at Fresno and Madera, California, respectively.[7]

IV. BACKGROUND

A. Origins of the RMR Contracts and the April 1999 Settlement

Since the beginning of the restructuring process in California, it has been recognized that certain generating units, because of their location and the configuration of the transmission system, are needed to provide energy or ancillary services during certain hours to assure the reliable operation of the ISO controlled grid. It has also been recognized that the same units will be able to exercise locational market power during those hours. The underlying purpose of the RMR contract is to assure that the ISO will be able to call upon these units when it needs them for reliability purposes or to manage intra-zonal congestion and that their owners will not be able to exercise market power by withholding the units' output.

Accordingly, in seeking authorization from FERC, in accordance with the CPUC's restructuring orders, to make sales at market-based rates from what were then their own generating units, PG&E, along with SCE and SDG&E, proposed that those units that could otherwise exercise locational market power be made subject to must-run contracts with the ISO. By order issued October 30, 1997, the Commission approved the companies' market-power mitigation measures, including the RMR contracts.[8] On October 31, 1997, PG&E tendered for

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[7] PG&E also owns and operates units 1, 2, 3 and 4 of the Hunters Point power plant located in San Francisco, California. PG&E's Hunters Point units are operated as Condition 2 RMR units and are not at issue in this Joint Complaint. See the discussion of Condition 1 and Condition 2 RMR units at page 9, below. In addition, PG&E operates several more units designated to be RMR units in 2002. These units which are not yet under contract include: Spaulding 2, Alta 1&2, Deer Creek, Stanislaus, Spring Gap, Narrows 1, Battle Creek Watershed, South Yuba Watershed and Mokuelemne Watershed.

[8] Pacific Gas and Electric Co., 81 FERC ¶ 61,122 (1997).

filing in Docket No. ER98-495 unexecuted must-run contracts for the PG&E units that had been designated by the ISO as RMR units. The terms of those contracts were substantially uniform, but each contract reflected the individual costs and operating characteristics of the units it covered.[9] On December 17, 1997, the Commission accepted the contracts for filing, set them for hearing and allowed them to go into effect, subject to refund, with the commencement of ISO operations on March 31, 1998.[10]

Thereafter, in 1998 and 1999, PG&E divested itself of the majority, but not all, of its RMR units. Most of the retained PG&E units have been designated as Condition 1 RMR units for 2002 and are the subject of this Joint Complaint. Under Sections 5.2.7 and 5.2.8 of its tariff, the ISO bills PG&E (the Participating Transmission Owner) for the costs paid by the ISO under the RMR contract for a given unit. Ultimately, these costs become the responsibility of PG&E's end-use customers.[11] In April 1999, parties representing a broad cross section of affected interests, including all of the complainants and PG&E, reached a partial settlement on the terms

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[9] The ISO had filed a pro forma version of the contract in March 1997 and amended that version in August 1997. Id. at 61,557.

[10] Pacific Gas and Electric Co., 81 FERC ¶ 61,322 (1997).

[11] Under the CPUC accounting procedures currently in force, the costs and revenues associated with PG&E's RMR contracts "net out." PG&E books all of its costs into the Transition Revenue Account ("TRA"). PG&E also books all of its revenues into the TRA. The TRA contains a line item for RMR costs. It also incorporates revenues from the generation accounts carried over from PG&E's "Generation Memorandum Accounts." These "Gen Memo" accounts include RMR revenues.

Complainants herein are concerned that this may not always be the case. Specifically, on April 6, 2001 PG&E filed for bankruptcy. (Pacific Gas and Electric Company, U.S. Bankruptcy Court, Northern District of California (San Francisco) Bankruptcy Petition #01-30923.) In its bankruptcy proceeding, PG&E on September 20, 2001, proposed a restructuring under Chapter 11 of the Bankruptcy Code (11 U.S.C. Section 1101 *et seq*.) under which most of its RMR units would become the property of an unregulated entity. If this restructuring plan were to be approved by the bankruptcy court, the costs of the RMR contracts associated with the facilities divested pursuant to the bankruptcy reorganization would thereafter be borne by PG&E's ratepayers, but the financial benefits of these contracts would flow solely to the new, unregulated owner. Costs and revenues would cease to "net out." Under of a wholly new *pro forma* RMR agreement to supersede the contracts then in effect, and on the unit-specific rates and terms that would apply under that contract for each of the units then designated as RMR. That settlement (the "April 1999 settlement") reserved for litigation a number of issues relating to the new contract, as well as certain issues relating to the old ones. Among the unresolved issues was the level of the Fixed Option Payment.[12] The Commission approved the settlement on May 28, 1999, and the new contracts took effect on June 1 of that year.

In August 2000, the parties reached further consensus regarding 12 of the 17 issues outstanding from the April 1999 settlement (the "August 2000 settlement").[13] Of the five remaining issues, three (including the level of the Fixed Option Payment) were settled on an owner-specific basis with respect to some RMR owners and were litigated with respect to others as discussed below; a fourth issue (oil burning capability) is still being addressed by the relevant parties; and the fifth issue (termination fees) was submitted to the Commission for decision. The August 2000 settlement required further amendments to the RMR contract, and it is this version of the RMR contract that is in effect today.

B. Terms of the RMR Contract

The *pro forma* version of the RMR contract approved by the Commission in the August 2000 settlement is Appendix A to the Stipulation and Agreement filed in Docket Nos. ER98-

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such circumstances, the new, unregulated owner of the RMR units would have a financial incentive to maximize the payments that these facilities receive under the RMR contracts, irrespective of the justification for said payments.

[12] Also left open were what share of the costs of capital additions to RMR units should be borne by the ISO and what share of the costs of certain repairs to RMR units should be borne by the ISO. It should be noted that all costs incurred by the ISO are paid by the Participating Transmission Owner.

441-021, *et al.*, on August 14, 2000.[14] The contract requires the owner of the RMR unit to provide energy and ancillary services when called upon to do so by the ISO in order to meet local reliability needs or to manage intrazonal congestion.[15] In return, the owner is entitled to receive the payments specified in Section 8 of the contract. There are also separate provisions providing compensation in the event that the owner is required by the ISO, or by its obligations under the contract, to make certain repairs or capital additions.

Owners may choose to operate under "Condition 1" or "Condition 2," but may not, absent the ISO's consent, transfer between conditions, at intervals of fewer than 12 months. Condition 2 assures the owner the recovery of its stipulated Annual Fixed Revenue Requirement, which includes both "sunk" and "going-forward" fixed costs provided that it meets certain availability standards; however, Condition 2 substantially restricts the unit from participation in market transactions.[16] Condition 1 does not assure the owner the recovery of all of its fixed costs, but allows the owner to participate in the market and to retain all of the revenues that it earns by virtue of doing so.

The RMR contract is in effect from year to year and renewable at the option of the ISO. The Annual Fixed Revenue Requirement is adjusted annually, beginning January 1, 2002, under

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[13] See Southern California Edison Co., 93 FERC ¶ 63,003 (2000), certifying the August 2000 settlement to the full Commission. The settlement was approved in California Independent System Operator Corporation, 93 FERC ¶ 61,089 (2000).

[14] For brevity, the contract is not submitted herewith, but rather is incorporated by reference. Similarly, the testimony and exhibits cited in the declarations attached hereto are, to avoid undue bulk, incorporated by reference as listed in Appendix F.

[15] See Section 4.1(b) and (c) of the contract.

[16] The RMR units owned by Duke Energy Oakland, LLC and PG&E's units at Hunters Point are the only units currently under Condition 2.

a formula rate set forth in Schedule F of the contract. This formula reflects actual costs for each unit in the 12 months ending the previous June 30.

Under Section 8.1(a) of the contract, an owner operating under Condition 1 is paid a Monthly Availability Payment, a sum that will vary with the availability of the unit, but that is not to exceed, over the course of the year, the Annual Fixed Revenue Requirement for the unit. The Fixed Option Payment, the subject of this complaint, is the annualized form of the Monthly Availability Payment. Section 8.1(a) also provides for a Monthly Surcharge Payment to cover the ISO's share, if any, of the costs of certain capital additions and repairs.

Additionally, the owner receives under Section 8.1(b) a Variable Cost Payment to compensate it for variable costs, such as fuel and variable O&M, incurred in providing each megawatt-hour of energy delivered under the contract. The owner also receives a separate prepaid start-up payment to compensate it for the start-ups necessary to respond to ISO dispatch notices. To the extent that the ISO calls upon a unit during any year for service hours, energy, or start-ups that exceed certain historical norms, the ISO is required under Section 8.1(f) and (g) to make additional payments specified in Schedule G of the contract. If compliance with the ISO's instructions to provide ancillary services or energy requires the owner to decrease the unit's output of either market energy or ancillary services, the owner receives, under Schedule E of the contract, a "Pre-empted Dispatch Payment" that is intended to make the owner whole in relation to the original market transaction.

Section 8.5 of the RMR contract provides for certain non-performance penalties. Those penalties cannot exceed the sum of the Monthly Availability Payment and Monthly Surcharge Payment that the owner would otherwise receive absent the penalties for the month in which the non-performance occurred. The penalty rate is a function of the Monthly Availability Payment.

C. Fixed Option Payment Settlements

By a series of settlements entered into in late 1999 and early 2000, the affected parties, including PG&E, agreed to the Fixed Option Payments that would apply to the RMR units owned or operated by specific firms through December 31, 2001.[17] As provided in the April 1999 settlement, these rates were to remain in effect until superseded under Section 205 or 206 of the Federal Power Act, with any superseding rates to be effective no sooner than January 1, 2002.[18] The individual settlements varied by period and by unit. In the case of PG&E, the Fixed Option Payments are 50 percent of Annual Fixed Revenue Requirement, for all units except for the San Joaquin River units. The Fixed Option Payments for the San Joaquin River units is 20% of the Annual Fixed Revenue Requirement. The currently effective payments, stated as a percentage of Annual Fixed Revenue Requirement (i.e., the Fixed Option Payment Factors), for the Condition 1 PG&E units that were covered by such settlements, and that have been re-designated by the ISO as RMR units for 2002,[19] are shown in Appendix C.

D. Docket No. ER98-495-000

At the hearing in Docket No. ER98-495-000, conducted in March 2000, the ISO, PG&E, SDG&E, SCE, the CPUC, and the EOB, supported by the Commission trial staff, advocated the "net incremental cost" method for determining the Fixed Option Payment applicable to

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17 See, e.g., Geysers Power Co., LLC, 90 FERC ¶ 61,096 (2000); Southern California Edison Co., 90 FERC 61,091 (2000); Pacific Gas and Electric Co., 90 FERC ¶ 61,023 (2000); Pacific Gas and Electric Co., 90 FERC ¶ 61,049 (2000); Duke Energy Moss Landing, LLC, 90 FERC ¶ 61,073 (2000); Cabrillo Power I LLC and Cabrillo Power II LLC, 92 FERC ¶ 61,116 (2000); and Duke Energy South Bay LLC, 92 FERC ¶ 61,155 (2000).

18 See Article I.C of the Stipulation and Agreement filed April 2, 1999 in Docket Nos. ER98-441, *et al.*

19 Under Section 5.2.5 of its tariff, the ISO annually identifies units, that, because of their location and the characteristics of the transmission system, it will need during the coming year for local reliability purposes.

Southern's RMR units at Pittsburg, Potrero and Contra Costa.[20] Under the net incremental cost method, the Fixed Option Payment is calculated in a manner designed to put the owner into the same position as it would have been but for the RMR contract, taking into account administrative and other out-of-pocket costs, opportunity costs, and certain benefits to the owner created by the contract. In that proceeding, PG&E itself presented testimony applying that method to Southern's units. Southern, arguing that the RMR contract is akin to a traditional contract for the purchase of energy and capacity, advocated a method whereby the Fixed Option Payment for a given unit would be determined, broadly speaking, by the percentage of total hours in which the ISO called upon that unit to run.[21]

In his initial decision, the presiding Administrative Law Judge emphatically rejected Southern's position and adopted the net incremental cost method:

> RMR obligations are simply contractual mechanisms enabling generators enjoying unique -- and therefore essential -- locations in the interconnected transmission grid to participate in competitive markets for energy and ancillary services by mitigating those generators' ability to exploit local market power in limited circumstances. It follows that RMR unit availability should be compensated in an economically "transparent" manner: appropriate compensation should mitigate local market power, but neither unnecessarily advantage nor unnecessarily disadvantage RMR unit participation in competitive markets for energy and ancillary services. Net incremental cost compensation achieves these objectives.[22]

The Presiding Judge also found that the compensation of an RMR facility at a rate that exceeds the facility's net incremental cost would be inequitable to consumers and lead to a distortion of

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[20] The same parties had advocated the same method in separate proceedings concerning Duke's South Bay plant, Cabrillo I's Encina plant, and Cabrillo II's combustion turbines before those proceedings settled.

[21] See Pacific Gas and Electric Co., Initial Decision, 91 FERC ¶ 63,008, at 65,107.

[22] Id., 91 FERC at 65,113 (footnote omitted).

the competitive market for energy and ancillary services by subsidizing RMR units' operations, giving those units a competitive advantage over generating facilities that are not parties to an RMR contract.[23]

Briefs on exceptions to the initial decision and reply briefs were filed in the summer of 2000, and the case is currently awaiting decision by the Commission.[24]

V. THE CURRENTLY EFFECTIVE FIXED OPTION PAYMENTS ARE UNJUST AND UNREASONABLE

A. Fixed Option Payments Exceeding Net Incremental Costs Are Unjust and Unreasonable

As stated above, and as found by the Presiding Judge in Docket No. ER98-495-000,[25] the distinguishing characteristic of must-run units is that, because they are needed at certain times to maintain local area reliability, they may, by the threat of withholding, exercise locational market power. The fundamental purpose of the RMR contract is to mitigate that market power, enabling the owner to participate in the market on the same basis as other generators that have been granted authority to charge market-based, rather than cost-based rates.

In light of that purpose, the Fixed Option Payment cannot lawfully exceed the sum of the costs (other than the opportunity costs of not being able to exact monopoly rents) that are imposed on the owner by virtue of operating under the RMR contract. To put it another way, there is no legitimate reason why the RMR contract should put the owner in a better position

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[23] Id.

[24] In a letter dated September 14, 2001 (Appendix D hereto), the ISO, PG&E, SDG&E, and SCE requested that the Commission act promptly to decide the case, noting that it had been pending on exceptions for more than a year, and that the currently effective rates have a significant impact on PG&E's customers.

than the position it would be in if it did not have locational market power and were not subject to the requirements of the RMR contract. That is precisely what the Presiding Judge concluded in Docket No. ER98-495-000: "appropriate compensation should mitigate local market power, but neither unnecessarily advantage nor unnecessarily disadvantage RMR unit participation in competitive markets for energy and ancillary services."[26] To the extent that the Fixed Option Payment puts the owner in a better position than the one it would occupy without locational market power and absent the burdens (and benefits) of operating under the RMR contract -- i.e., to the extent that the payment exceeds the net incremental costs imposed by the contract -- that payment is manifestly unjust and unreasonable.

B. The Existing Payments Exceed Net Incremental Costs.

1. Categories of Costs and Benefits

In its testimony in Docket No. ER98-495-000, PG&E itself identified, and quantified, four types of incremental costs to RMR owners arising out of the RMR contract: administrative costs, certain costs of keeping a unit operational for short periods, the net costs of operating and maintaining certain units that would otherwise shut down, and certain opportunity costs of having to run when dispatched by the ISO.[27] PG&E also described and calculated certain offsetting benefits of running at the ISO's expense in low-load hours.[28] Those costs and benefits

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25 "The same holds true for an analysis of the RMR obligations' fundamental purpose. That purpose indisputably is to mitigate the potential for RMR owners to exercise local market power at times when the units are essential to transmission grid reliability." Pacific Gas and Electric Co., *supra*, 91 FERC at 65,111.

26 Id. at 65,113.

27 See the testimony of Joe D. Pace, Exhibit No. PGE-1 at 15-16 in Docket No. ER98-495-000; see also Exhibit Nos. PG&E 3 (at 19-24, 27-30), 5, 6, 9-11, 13 (at 5-9, 11-13), 15, and 16 in Docket No. ER98-495-000.

28 See Exhibit Nos. PGE 3 (at 24-27), 7, and 8 in Docket No. ER98-495-000.

provided the basis for the calculation of net incremental costs presented by PG&E. The Presiding Judge found the resulting payment fully compensatory for the RMR unit:

> I find that this methodology fully compensates Southern Parties for all costs--including fixed costs, variable costs, and reasonably calculated opportunity costs--associated with their RMR obligations, and therefore adopt it for purposes of this proceeding.[29]

Indeed, the Judge found the logic and calculation so compelling that he rejected, as an unnecessary "fudge factor," the proposal by the parties advocating the net incremental cost method that the fixed option payment be set at 110 percent, rather than 100 percent, of net incremental costs calculated in the manner described above.[30]

2. Incremental Costs

To estimate the net incremental costs for PG&E's Condition 1 RMR units at issue in this proceeding, the ISO staff has analyzed the incremental costs for said units in light of certain changes in the market structure that have occurred since the hearings in Docket No. ER98-495-000. These calculations are explained and set forth in the declaration of Robert Kott, attached hereto as Appendix E.

As explained in Mr. Kott's declaration, the first type of incremental costs includes the out-of-pocket costs imposed by the contract, which are the costs of having to administer the contract, to issue invoices, to process settlements, and the like. Absent the contract, the owner would have to administer some other measure to mitigate its local market power, but, to err on the side of caution, it is assumed that some administrative costs are incremental. The

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29 Pacific Gas and Electric Co., *supra*, 91 FERC at 65,115.

30 Id.

calculations of those costs are set forth in Mr. Kott's declaration. Those costs were derived on the basis of the estimated amount of employee time needed to administer the RMR contracts.

The second type of incremental cost identified in Mr. Kott's declaration is the cost of keeping a unit operational for short periods of relatively low demand when, absent the RMR contract, the unit would otherwise have been temporarily shut down. The declaration concludes that such a short-term shutdown strategy would be unlikely to be profitable for the PG&E units in question.

The third type of incremental cost that may, at least in theory, be imposed by the RMR contract is the fixed cost of operating and maintaining a unit that, absent the RMR obligation, would simply be shut down permanently because it was not profitable. PG&E's Condition 1 RMR units may be expected to earn more in net revenues than it costs PG&E in fixed operation and maintenance outlays to keep them running and accordingly would not be subject to this type of incremental cost. If it were otherwise, prior to the time that the currently effective Fixed Option Payments were set, PG&E would have opted for full cost of service treatment for such units under Condition 2, as it did for its Hunters Point units. As explained by Mr. Kott, in light of the prices that have prevailed in the California wholesale market since the spring of 2000, and the fact that PG&E has not chosen to transfer its Condition 1 RMR units to Condition 2 RMR units, it is fair conclude that PG&E's Condition 1 RMR units are economically viable.

The fourth type of incremental cost is the opportunity cost imposed upon the RMR owner by the contract's must-run obligation. PG&E's testimony in Docket No. ER98-495-000 identified one such potential cost: for certain hours, an owner may have committed to make a sale of energy only to find, as the hour approaches, that the price of energy in the ISO's real-time market is likely to be lower than its own variable cost of generating. Absent the RMR contract, the owner could, if it accurately foresaw the circumstance and could adjust its operations in time, not run its own unit but instead purchase the necessary energy in the real-time market to satisfy its bilateral contractual obligation; the RMR contract denies the owner that option in hours when the ISO provides a dispatch notice for the owner's unit.

As explained by Mr. Kott, that cost is likely non-existent for PG&E's San Joaquin River and Humboldt units given their variable costs. For the Helms Facility, based on the variable costs set forth on PG&E's 2000 RMR invoices, it is possible that up to $690,000 of opportunity costs could materialize. However, even these costs have, in all probability, been substantially eliminated by subsequent changes in the market rules. Most notably, the ISO's tariff has been amended specifically to make uninstructed negative deviations from scheduled generation more costly.

On the basis of his assessment of the four types of incremental costs described above, Mr. Kott concludes that those costs for the PG&E units under consideration are likely well below the level of the respective Fixed Option Payments currently in effect for those units.

3. <u>Incremental Benefits</u>

As explained by PG&E's own testimony in Docket No. ER98-495-000, there are certain hours during periods of relatively low demand in which the ISO pays the owner to operate an RMR unit at minimum load, or to start the unit up, even though, given the prices likely available in the market, the owner would not otherwise do so. Because it is running at the ISO's expense, the unit is then in a position to make sales into the market in succeeding hours when market prices exceed its variable costs, even though, absent the RMR dispatch, it would not have been able to do so.[31]

RMR benefits are logically offsets against both the out-of-pocket and opportunity costs described above in calculating net incremental costs. Because, without any netting of such benefits, those costs are already well below the currently effective level of Fixed Option Payments, they have not been quantified here. It should be noted, however, that those benefits actually exceeded incremental opportunity costs for several of the units at issue in the prior round of litigation.[32]

The analysis presented by Mr. Kott, is, to be sure, based on estimates and, to some extent, on inference from cost figures from prior periods. It is, however, more than sufficient to demonstrate that the currently-effective Fixed Option Payments that PG&E receives for its Condition 1 RMR units are significantly higher than could be justified under the net incremental cost method and thus are plainly unjust and unreasonable. The precise level at which those payments should be set by the Commission under Section 206 can be determined on the basis of more complete and current data available through discovery, or by other means, after the institution of a Section 206 investigation.

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31 See Exhibit Nos. PGE 3 (at 24-27), 7, and 8 in Docket No. ER98-495-000.

32 See Exhibit No. SD-19 in Docket No. ER98-496-000 at 5 (the testimony of Robert B. Anderson in relation to Duke's units calculated opportunity costs at $674,057 and offsetting benefits at $2,893,519).

VI. THE COMMISSION SHOULD ESTABLISH A REFUND EFFECTIVE DATE OF SIXTY DAYS FROM THE DATE OF THIS FILING (JANUARY 12, 2002), BUT DEFER FURTHER PROCEEDINGS HEREIN PENDING ITS DECISION ON EXCEPTIONS IN DOCKET NO. ER98-495-000

Under Section 206 (b), the Commission is required, upon the institution of an investigation into the justness and reasonableness of currently effective rates, to establish a refund effective date, which can be no earlier than 60 days after the filing of the complaint that precipitated the investigation.[33] To assure consumers the maximum relief from rates that are ultimately found to be unjust and unreasonable, the Commission can and should establish sixty days from the date of this filing (January 12, 2002) as the refund effective date in this proceeding.

At the same time, the undersigned parties recognize that Docket No. ER98-495-000 presents issues closely similar, if not identical, to those presented here as to how the Fixed Option Payment is properly determined under the just-and-reasonable standard. The Commission's decision on exceptions in Docket No. ER98-495-000 will provide relevant precedent in the resolution of the issues raised by the instant complaint. Setting this case for hearing and resolution by an administrative law judge while Docket No. ER98-495-000 is still pending on exceptions would waste the resources of the parties and the Commission. The more efficient course, we believe, would be for the Commission, having set a refund effective date, to defer further action on this case until it has ruled in Docket No. ER98-495-000.[34] At that point,

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[33] Whenever the Commission institutes a proceeding under this section, it shall establish a refund effective date. Generally, in the case of a proceeding instituted on complaint, the refund effective date should be no earlier than the date 60 days after the filing of such complaint nor later than 5 months after the expiration of such 60-day period. 16 U.S.C. § 824e(b).

[34] The Commission followed a similar procedure in Pacific Gas and Electric Co., 90 FERC ¶ 61,010 (2000). It there accepted a tariff filing and suspended that filing subject to refund, then deferred the hearing pending the decision on exceptions in another case. Id. at 61,023.

this case can proceed to adjudication on those issues that remain, issues that are likely to involve the implementation of the method endorsed by the Commission, rather than an *ab initio* determination of which method to apply.[35]

VII. CONCLUSION

For the reasons described above, the Commission should institute a proceeding under Section 206 of the Federal Power Act to investigate the Fixed Option Payments currently being charged by PG&E under its Condition 1 RMR contracts with the ISO. The Commission should establish a refund effective date of sixty days from the date of this filing (January 12, 2002) and defer further action herein until it has ruled on the pending exceptions in Docket No. ER98-495-000.

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[35] In proposing deferral of this proceeding, the complainants in no way wish to suggest that the Commission should likewise defer action in Docket No. ER98-495-000. To the contrary, as noted above, the complainants have recently urged the Commission to act promptly in that docket in light of the level of current payments being borne by PG&E's customers under the currently effective Fixed Option Payment for the RMR units at issue.

Respectfully submitted,

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November 13, 2001