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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Gas and Electric Company	)	Docket Nos. ER98-495-000
	)	ER98-1614-000
	)	ER98-2145-000,
		and ER99-3603-000

JOINT BRIEF OPPOSING EXCEPTIONS OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION,
PACIFIC GAS AND ELECTRIC COMPANY,
SAN DIEGO GAS & ELECTRIC COMPANY,
AND SOUTHERN CALIFORNIA EDISON COMPANY

Pursuant to the Rule 711 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.711 (1999), the California Independent System Operator Corporation ("ISO"), Pacific Gas and Electric Company ("PG&E"), San Diego Gas & Electric Company ("SDG&E"), and Southern California Edison Company ("Edison") (together, "Signatories"), hereby oppose the Brief on Exceptions filed by the rate applicants in these proceedings, Southern Energy Delta, L.L.C., and Southern Energy Potrero, L.L.C. (collectively, "Southern Parties"). In their Brief on Exceptions ("Southern Brief"), Southern Parties have all but ignored substantial record evidence supporting the Administrative Law Judge's well-reasoned Initial Decision ("I.D.") in this case. Unable to identify any errors in the I.D., Southern Parties essentially only re-argue issues the Administrative Law Judge already has considered and addressed. The Commission should dismiss the allegations of error and affirm the I.D.

I. INTRODUCTION AND SUMMARY OF SIGNATORIES' POSITION

This case concerns the level of Availability Payments under the reliability-must run contracts between Southern Parties and the ISO ("RMR Agreements"). These costs ultimately are borne by PG&E's transmission system ratepayers. It is not disputed that the RMR Agreements are needed to mitigate the local market power of Southern Parties' generating units, at times when these units are needed for local area reliability on the ISO-controlled grid.[1/] The simple, essential obligation imposed on Southern Parties by the RMR Agreements is that they *not withhold* energy and ancillary services at times when the generator possesses market power.

Importantly, the generator remains free at all times to sell its output (energy and ancillary services) at market-based prices, with potentially unlimited profits, and without any obligation to credit back to transmission system ratepayers any of the revenues it earns from these market activities. The RMR owner also has the option to elect "Condition 2" status, whereby its full fixed costs ("Annual Fixed Revenue Requirement" ("AFRR")) are paid by the ISO, but the unit owner under Condition 2 is not permitted to participate in energy and ancillary services markets, and must credit back to the ISO any market revenues it receives.

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1 / "Southern Parties do not dispute that one of the important functions of the RMR Agreements is to mitigate the potential exercise of local market power . . . ." (Southern Brief at 50.)

The I.D. correctly found that pricing of RMR Agreements in an unbundled environment is an issue of first impression before this Commission. (I.D., *mimeo* at 18, 32-33.) The Signatories respectfully urge the Commission to affirm the I.D. in this case, in order to provide guidance as to the proper approach for computing RMR compensation in California. It is essential for the benefit of consumers, and for the development of California's competitive market, that electric generators be neither over-compensated, nor under-compensated, for meeting the reliability obligations they accept as a condition of their authority to sell energy and ancillary services at market-based rates. RMR compensation based on the generator's net incremental cost, as the I.D. found, is fully compensatory to the owner, while also being fair to consumers by not requiring them to subsidize the owner's market activities. (I.D., *mimeo* at 25-29.) The I.D. concluded that the RMR Availability Payments should be set at a level that will "neither unnecessarily advantage nor unnecessarily disadvantage RMR unit participation in competitive markets for energy and ancillary services." (*Id.* at 25.) The net incremental cost method of compensation precisely achieves this goal.

The net incremental cost methodology is very straightforward. To compute an Availability Payment based on this method, four steps are required. (*See* I.D., *mimeo* at 28-29.) First, a calculation is made as to the incremental administrative costs incurred by the Owner to meet its RMR obligations. Next, an "opportunity cost" calculation is made by quantifying the Owner's opportunity costs, and subtracting from them any opportunity *benefits* conferred by the RMR Agreements; however, as the I.D. found, rates are not reduced below the level of the incremental administrative costs computed in step one, above. Third, the "going forward" costs of each unit are computed, based on a conservative projection of market revenues. Finally, the RMR Availability Payment is set at the higher of net incremental cost or net going forward cost. As the Administrative Law Judge concluded: "I find that this methodology compensates Southern Parties for all costs -- including fixed costs, variable costs and reasonably identifiable opportunity costs -- associated with their RMR obligations, and therefore adopt it for purposes of this proceeding." (I.D., *mimeo* at 29.)

The I.D. appropriately recognized (I.D., *mimeo* at 21, 23-24) that Southern Parties are authorized to sell energy and ancillary services at unregulated prices, and hence to earn potentially unbounded profits. Accordingly, Southern Parties' proposal to collect large amounts of fixed costs (including sunk costs) from the ISO under the RMR Agreements would result in an unwarranted subsidy of these market operations by captive transmission system ratepayers. It would leave Southern Parties in a much better position than an otherwise similarly situated merchant plant operator who does not have locational market power. The I.D. found (I.D., *mimeo* at 27) that RMR compensation at the high levels proposed by Southern Parties (equivalent, on a combined basis, to 77 percent of Southern's total AFRR) would have the perverse effect of rewarding the RMR generator for the very market power the RMR Agreements are intended to mitigate.

The Commission should affirm the essential findings of the I.D. regarding RMR compensation. By affirming the I.D., the Commission will set an important precedent for the cost of maintaining transmission system reliability in the competitive California market.

The Commission also may wish to consider the modest additional incentive payment supported by the Signatories, equal to 10 percent of the owner's total incremental costs (fixed and variable). This would provide an extra incentive for the RMR generation owner to maintain the unit's availability.[2/]

II. SUMMARY OF THE SIGNATORIES' RESPONSES TO THE VARIOUS SPECIFICATIONS OF ERROR ASSERTED BY THE SOUTHERN PARTIES

As required by Rule 711(b)(3)(i) of the Commission's Rules of Practice and Procedure, the following is a list of the specifications of error asserted by Southern Parties in their Brief on Exceptions (at 20), each followed by a description, in summary form, of the Signatories' response in opposition. A fuller discussion of each of the Signatories' responses is provided in subsequent sections of this Brief.

2/ If the Commission does decide to include an "adder" as an incentive payment, however, the adder should be calculated based on 10 percent of the Owner's total net incremental costs, not based on a percentage of AFRR (as Staff proposed). As the I.D. concluded based on the testimony and other record evidence in this proceeding, AFRR includes sunk costs, and there is no justification for including sunk costs in RMR Availability Payments. (*I.D.*, *mimeo* at 27-28.) The appropriate "adder" calculation, based on Signatories' proposal, is shown in Appendix 2 to this Brief.

In summary, it is clear upon review of Southern Parties' Brief on Exceptions that they are merely rehashing arguments that already were considered, and dismissed for sound reasons, by the Administrative Law Judge in the I.D. There is no basis for the Commission to revisit any of the I.D.'s rulings on these points.

Southern Parties' Specification of Error No. 1:

1. The Initial Decision fails to specify the rates that would result from application of the net incremental cost theory, and thus fails to consider whether that methodology produces a just and reasonable result in this case.

Summary of Signatories' Response: The I.D. requires, in accordance with normal Commission practice in rate proceedings, that Southern Parties make a compliance filing specifying the precise rates that will result from the approved pricing methodology. (I.D., *mimeo* at 35 (ordering paragraph). The I.D. provides exact citation to exhibits and other evidence in the record from which the required rate calculations must be made. (*See id.* at 28-29.) There is nothing exceptionable about the fact that the I.D. does not contain the actual rate calculations, but instead leaves this task to Southern Parties' compliance filing.

The I.D. persuasively explains (*mimeo* at 25-29) why the resulting rate levels are just and reasonable. These rates are fully compensatory. As such, they cannot be deemed "confiscatory." They will leave Southern Parties no better off, and no worse off, than a pure merchant power plant operator whose generating units are not needed for local reliability and who consequently does not have locational market power.

Southern Parties' comparisons between the rate levels required by the I.D., and the rate levels agreed to in settlements reached by other RMR owners, are misplaced and unconvincing. Southern Parties chose to pursue litigation rather than settlement. Having made that choice, they cannot reasonably complain about the litigation outcome, by comparing it to settlements reached by other RMR owners. Numerous Court and Commission decisions over the years confirm that such comparisons between litigated rates and settlement rates are generally disfavored.

Southern Parties' Specification of Error No. 2:

2. The Initial Decision Errs in concluding that RMR obligations are not a discrete product or service.

Summary of Signatories' Response: In the I.D., the Administrative Law Judge carefully and fairly considered all of the record evidence on the central question as to whether RMR obligations are a form of "capacity" contract or merely a market power mitigation device. (I.D., *mimeo* at 19-22.) He dismissed Southern Parties' attempt to analogize the RMR Agreements to capacity contracts, finding that "[t]he record demonstrates that the similarities Southern Parties cite to support the capacity reservation analogy are superficial." (*Id.* at 20.) The key distinction, as the I.D. found, is that, "whereas a traditional firm capacity service provider is restricted from selling output (e.g., energy/ancillary services) to third parties in the event the capacity purchaser calls on the output, Southern Parties' RMR availability obligations impose no such restriction." (I.D., *mimeo* at 20 (record citations omitted).) Rather, Southern Parties remain free to sell all of their output at market-based prices and enjoy unlimited profits. RMR obligations, the Administrative Law Judge concluded, "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 the generators' ability to exploit local market power in limited circumstances." (*Id.* at 25.)

There is ample and persuasive evidence in the record in support of the I.D.'s conclusions on this key issue, including extensive expert testimony by an impressive panel of eminent economists. The record evidence also includes a financing memorandum that Southern Parties gave to prospective lenders in September 1999, which acknowledged that the RMR Agreements did not impound the economic value of the generators. (Ex. PGE-30.) That document flatly contradicts Southern Parties' testimony here, which sought to analogize the RMR Agreements to capacity contracts. The I.D., accordingly, rejected as unfounded, and unfair to consumers, Southern Parties' proposal to allocate to the ISO a huge percentage of the fixed cost of these plants (including sunk costs), as if the ISO enjoyed a "capacity" right.

<u>Southern Parties' Specification of Error No. 3</u>:

3. The Initial Decision errs in finding that the RMR contracts are merely market mitigation tools.

<u>Summary of Signatories' Response</u>: The I.D. contains a thoughtful, carefully reasoned analysis, examining the "hybrid" character of Southern Parties' generating units, which perform both a merchant function and a reliability function.

(*See* I.D., *mimeo* at 18-22.) The Administrative Law Judge considered, in an objectively fair fashion, Southern Parties' argument that RMR availability obligations are analogous to traditional "capacity" arrangements and should be priced accordingly. (*Id.* at 20.) Ultimately, the I.D. concluded that Southern Parties' capacity analogy had been "discredited" by record evidence (*Id.* at 23), which showed that "the similarities Southern Parties cite to support the capacity reservation analogy are superficial." (*Id.* at 20.) The "fundamental purpose" of the RMR Agreements, as the I.D. noted, "indisputably is to mitigate the potential for RMR unit owners to exercise local market power at times when the units are essential to transmission grid reliability." (*Id.* at 21.) The I.D. recognized that, absent the must-run obligation, "RMR unit owners' market-based rate authority would permit them to withhold – or threaten to withhold – essential transmission grid support, thereby artificially inflating the price of that support. . . ." (*Id.* at 22 (footnote omitted.) Accordingly, the I.D. concluded that RMR obligations "are not properly characterized as a discrete product or service" but rather must be viewed for what they are: "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 the generators' ability to exploit local market power in limited circumstances." (*Id.* at 22.) Absent such mitigation of their local market power, the generators would be required "to charge cost-based rates (or some functional equivalent achieved through revenue credits, etc.) for the energy/ancillary services the units produce." (*Id.*)

These conclusions are strongly supported by the testimony of several eminent economists in these proceedings. For example, Professor Paul Joskow of the Massachusetts Institute of Technology testified that the RMR owners, by agreeing to meet the ISO's RMR needs, are able to "mitigate the local market power that would otherwise have made it difficult, if not impossible, for them to meet the Commission's criteria for market-based pricing authority." (Ex. SCE-2 (Joskow-Direct), at 10:7-13). Similar testimony was provided by PG&E witness Dr. Joe Pace, SDG&E witness Dr. Larry Ruff, ISO witness Dr. Eric Hildebrandt, and indeed by Dr. Madian, a witness for Southern Parties. The Administrative Law Judge cited this testimony in support of his conclusion that the purpose of the RMR Agreements "indisputably is to mitigate the potential for RMR unit owners to exercise local market power at times when the units are essential to transmission grid reliability." (*See* I.D., *mimeo* at 21.)

There is thus an ample record basis for the Administrative Law Judge's well-reasoned conclusion that the RMR Agreements must be viewed in essence as a market power mitigation device, and not as a discrete "service."

<u>Southern Parties' Specification of Error No. 4</u>:

4. The Initial Decision errs in failing to uphold the terms of the April 2 Stipulation and Agreement.

<u>Summary of Signatories' Response</u>: The I.D. found no merit in Southern Parties' argument that the April 1999 Stipulation, which reserved the issue now before the Commission for decision, somehow foreclosed the use of a net incremental cost methodology, or alternatively that it required an allocation of sunk costs to the RMR Agreements as Southern Parties alleged. (I.D., *mimeo* at 32.) The April 1999 Stipulation used conspicuously broad language to state the issue reserved for litigation in this case. ("What is the appropriate level of the Fixed Option Payment under each revised RMR rate schedule?") It is apparent from this language that the parties were careful to leave themselves room to advocate a wide variety of potential outcomes. Southern Parties now would have the Commission re-write the reserved issue, so that instead of the broad language quoted above, the reserved issue would read narrowly: "What percentage of the settled fixed cost (AFRR) should be used to set the Fixed Option Payment under each revised RMR rate schedule?" But that is *not* how the Reserved Issue was stated by the parties to the April 1999 Stipulation (which included Southern Parties), and there is no basis for the narrow reading urged by Southern Parties.

The Administrative Law Judge considered this issue, and correctly found that there is nothing in the April 2 Stipulation, or in the underlying RMR Agreements, that can be said to foreclose the use of the net incremental cost method to set the level of the Availability Payments under the RMR Agreements. (I.D., *mimeo* at 32.) Nor is there any indication in either document that the parties bound themselves to accept sunk cost compensation in the Availability Payments. The fact that the April 2 Stipulation included an "Annual Fixed Revenue Requirement" ("AFRR") for each RMR unit, and that the AFRR included both sunk costs and going-forward costs, cannot fairly be interpreted to give Southern Parties a contractual right to sunk cost recovery. For Condition 1 units, the AFRR merely constitutes an agreed-upon *ceiling* on the amount of the Availability Payment. For Condition 2 units, the AFRR is needed to set the level of the Availability Payment. The I.D. properly dismissed Southern Parties' attempt to extrapolate from the specification of an AFRR in the RMR Agreement some implied requirement that the Availability Payment must include sunk costs. The broad wording of the reserved issue, quoted above, precludes any such conclusion.

Southern Parties' Specification of Error No. 5:

5. The Initial Decision errs in failing to consider the reasonable commercial expectations of the parties when the divestiture transaction was negotiated.

Summary of Signatories' Response: Contrary to the allegation of error, the I.D. contains a full and fair evaluation of the evidence regarding Southern Parties' alleged commercial expectations regarding RMR compensation at the time they elected to purchase the subject power plants. (*See* I.D., *mimeo* at 31-32.) The Southern Parties simply failed to show any credible basis for their allegation of a "bait and switch" by PG&E and the ISO. In effect, Southern Parties seek to justify inflating the level of the Availability Payments above a level that fully compensates them for all of the net incremental costs imposed on them by the RMR Agreements, based on an alleged commercial expectation of receiving some greater subsidy from the ISO and from captive ratepayers. Upon review of all the evidence, the Administrative Law Judge found absolutely no support for these contentions. (I.D., *mimeo* at 31-32.)

Southern Parties' Specification of Error No. 6:

6. The Initial Decision errs in finding that the net incremental cost approach provides the proper incentives for new transmission and generation resources.

Summary of Signatories' Response: Contrary to Southern Parties' allegation of error, the testimony in this case confirms that compensating existing RMR owners based on their net incremental costs sends precisely the correct price signal for potential replacement resources. In addition to the testimony of numerous witnesses for the consumer interests, Southern Parties' own expert witness offered virtually identical testimony under cross-examination. Accordingly, the I.D. found, on the basis of this uncontradicted evidence, that the net incremental cost method of compensation will provide the proper incentives for new transmission and generation resources that could replace existing RMR resources. (I.D., *mimeo* at 27-28.)

Southern Parties' Specification of Error No. 7:

7. The Initial Decision's net incremental cost formulation relies on highly speculative estimates of revenues and opportunity costs.

Summary of Signatories' Response: The I.D. found that PG&E's witnesses, on behalf of PG&E and the other consumer parties, had fully and fairly accounted for all incremental costs, including opportunity costs, incurred by Southern Parties in meeting their RMR obligations. (I.D., *mimeo* at 28-29.) Southern Parties had a fair opportunity on rebuttal to show any reasons why they might have believed these calculations to be erroneous or incomplete. (*See id.* at 28 and n. 29.) There is no basis for Southern Parties' claim that the incremental cost calculation is in any sense speculative or inaccurate. In fact, the calculation is very straightforward. Furthermore, the calculation offered by PG&E's witnesses if anything conservatively erred on the side of being over-inclusive, rather than under-inclusive, in measuring the costs that Southern Parties incur in meeting their RMR obligations.

Southern Parties' Specification of Error No. 8:

8. The Initial Decision errs in rejecting a Fixed Option Payment based on a reasonable allocation of the settled fixed annual revenue requirement.

Summary of Signatories' Response: The I.D. did not err in rejecting Southern Parties' proposal to allocate more than three-quarters of the settled fixed costs of the subject power plants (including "sunk" costs) to the ISO under the RMR Agreements. As the I.D. recognized, doing so would be antithetical to the competitive industry structure adopted in California. (*See* I.D., *mimeo* at 26-27.) Southern Parties sought and were granted the opportunity to charge market-based rates for the output of their generating units (energy and ancillary services), and hence to earn potentially unlimited profits. Their proposal to nonetheless allocate substantial sunk costs to the ISO under the RMR Agreements simply cannot be justified, and it was properly rejected by the Administrative Law Judge for the reasons stated in the I.D.

III. REBUTTAL OF POLICY CONSIDERATIONS CLAIMED TO WARRANT COMMISSION REVIEW

Rule 711(b)(3)(ii) of the Commission's Rules of Practice and Procedure requires that a Brief Opposing Exceptions must include "a rebuttal of policy considerations claimed to warrant Commission review." In their Brief on Exceptions (at 21-23), Southern Parties offer only three policy considerations on the basis of which they claim the I.D. should be "overturned." None has merit.

First, Southern Parties claim the Availability Payment levels authorized by the I.D. will not provide sufficient incentive, either for generators to locate new power plants in areas where they may be needed for system reliability, or for transmission owners to upgrade their transmission systems. (Southern Brief at 22.) This is manifestly incorrect. As the I.D. found, "compensating Southern Parties' RMR availability obligations at net incremental cost would provide appropriate price signals for potential replacement resources." (I.D., *mimeo* at 28.) The Administrative Law Judge further noted that including sunk costs in the Availability Payments, as

Southern Parties advocated, "would create perverse incentives to invest in duplicative or uneconomic generation, transmission and demand-side management" and would undermine the ISO's ability meaningfully to determine and evaluate economically efficient alternatives to RMR generation under its Local Area Reliability System process." (*Id.* (record citations omitted).)

These conclusions are fully supported in the record. Indeed, Southern Parties' own expert witness, Alan Madian, frankly acknowledged that one of the "few settled economic principles" is that "if you can achieve, acquire the same product or achieve the same service at a lower price, that is generally, you know, at a lower expenditure of resources, that's a good thing to do." (Tr. at 663:18 - 664:1.)[3/] Dr. Madian further testified that, in order to provide an efficient price signal for resources capable of replacing existing RMR units (whether transmission upgrades, alternative generating units, or other options), the price of the existing resource should be based on the incremental cost of that resource, "assuming simultaneous substitutability." (Tr. at 664:2-8 (as corrected).) Thus, Southern Parties' own witness conceded (i) that the best way to achieve an economically efficient result for replacement resources is to compensate current RMR owners based on their incremental cost, and (ii) that setting the price for a resource at a level substantially higher than the incremental cost of the incumbent supplier (as Southern Parties proposed in their case-in-chief) would

[3/] Although Dr. Madian's earlier deposition in this case was not received into evidence, he acknowledged that he had given similar testimony during his deposition. (Tr. at. 663:19-20.)

result in an unnecessarily high price signal for replacement resources, and hence social waste. As the ISO's expert witness, Dr. Hildebrandt, explained in his Rebuttal Testimony (Ex. ISO-5 (Hildebrandt-Rebuttal), at 10:10 - 11:21), pricing the existing RMR resource at such a high level would lead to uneconomic investments in replacement resources. Staff witness Sammon endorsed this same principle, using a simple example to demonstrate how charging sunk costs to the ISO under the RMR Agreements would create a "perverse incentive" for investments in uneconomic replacement resources. (Ex. S-12 (Sammon-Answering), at 21:1 - 22:17.)

The record thus strongly supports the Administrative Law Judge's conclusion that "compensating Southern Parties' RMR availability obligations at net incremental cost would provide appropriate price signals for potential replacement resources." (I.D., *mimeo* at 28.) Indeed, the testimony on this point is both compelling and unanimous.

Second, Southern Parties assert that their investor expectations have been upset by what they characterize as a "bait and switch" scheme by PG&E (from whom they acquired the subject power plants) and by the ISO. (Southern Brief at 22-23.) Southern Parties claim they "invested significant capital in the RMR units in the expectation that those units would receive compensation levels at approximately PG&E's revenue requirements." (*Id.*) They warn that, in future divestitures of utility-owned power plants, bidders "will have to think long and hard about making investments in divested RMR-like generating units." (*Id.*)

The Administrative Law Judge considered these same contentions, and found they lacked any basis whatsoever. Although "bait and switch" has become a centerpiece of Southern Parties' argument, they did not provide any credible evidence at the hearing to support this claim. For example, Southern Parties introduced no contemporaneous documents, nor any testimony by any percipient witness, to support the allegation that they relied on alleged assurances of sunk cost recovery when they bid on the power plants in November 1998. Upon review of all of the record evidence on this issue, the Administrative Law Judge concluded as follows:

> The exclusive record support for Southern Parties' claim that the decision to purchase PG&E's RMR units was based on PG&E assurances of sunk cost recovery via dedicated RMR compensation (Exh. SOU-10, at pp. 10-11; Exh. SOU-13, at pp. 16-17) is reflected in a PG&E "POWER PLANT SALE Confidential Information Memorandum." Exh. PGE-29. At page 21, the memorandum addresses "MULTIPLE REVENUE STREAMS" and states that "the Plants can generate revenues by using various sales methods." Exh. SOU-18, at p. 2. Listed among seven (7) illustrative bullet point sales methods is a reference to "revenues from the Master Must Run Agreement with the ISO." *Id.* This reference provides absolutely no support for Southern Parties' claim that their decision to purchase PG&E's RMR units was based on any seller assurance of sunk cost recovery through RMR compensation.
>
> The same holds true for Southern Parties' claim of contractual assurances. The fact that PG&E was receiving RMR compensation under the subsequently superceded "B" Contract fails to provide any legitimate basis for Southern Parties to conclude they were assured sunk cost recovery through RMR rates. The Commission never approved the "B" Contract, and in fact had expressed concern over the level of fixed cost recovery it provided, as well as expressly contemplating that it would be superceded. *See Pacific Gas and Electric Co., et al.*, 81 FERC ¶ 61,122, at pp. 61,555-56, 61,558 (1997). Moreover, while the "B" Contract provided sunk cost recovery, it also required all market revenues to be credited back to the

> ISO as an offset to that recovery. No such requirement was imposed on Southern Parties. In addition, the Commission order approving transfer of the RMR units at issue required Southern Parties to assume the units' RMR obligations *subject to the outcome of this proceeding*. *See Pacific Gas and Electric Co., et al.*, 86 FERC ¶ 62,248, at p. 64,383 and n.16 (1999).

(I.D., *mimeo* at 31-32 (emphasis in original; footnote omitted).)

The I.D. thus rests on a very solid basis in dismissing Southern Parties' "commercial expectations" claim. There is no reason for the Commission to disturb the Administrative Law Judge's well-placed findings in this regard.

Third, Southern Parties claim the I.D. is inconsistent with Commission policies regarding regional transmission organizations, as adopted in Commission Order No. 2000. (Southern Brief at 23.) They allege that the net incremental cost methodology for RMR Availability Payments is "antithetical" to the Commission's goals of "(1) separating transmission from market participants; (2) improving reliability through broader regional dispatch, and (3) reducing congestion on a market basis." (*Id*.) This assertion is completely erroneous. In fact, as the testimony in this case shows, the net incremental cost methodology for establishing RMR Availability Payments is entirely consistent with a market outcome. It gives the generator an unencumbered opportunity, and incentive, to participate actively in competitive markets for energy and ancillary services; it allows the ISO to meet essential reliability needs based on a sound cost-of-service methodology; and it maximizes market participation by the generators, which itself is the best way to assure system reliability. Far from being "antithetical" to the goals of Order 2000, the net incremental cost methodology endorsed by the I.D. in this case is entirely compatible with those goals, and it will affirmatively help to advance them.

IV. DETAILED RESPONSE TO SOUTHERN PARTIES' ARGUMENTS

This section of the Signatories' Brief Opposing Exceptions responds to the "Argument" portion of the Southern Brief, at 23-86. As discussed in summary form above, none of Southern Parties' various exceptions to the Administrative Law Judge's I.D. has merit. On the contrary, all of Southern Parties' arguments were considered and ultimately dismissed by the Administrative Law Judge on the basis of substantial evidence, for reasons that are well-stated in the I.D. Accordingly, the Commission should affirm the I.D.

For the sake of simplicity, the structure of the discussion in this section of Signatories' Brief Opposing Exceptions parallels exactly the main sections in the "Argument" portion of the Southern Brief.

A. Signatories' Response To Southern Parties' Allegation That The Initial Decision Erred By "Fail[ing] To Specify The Rates That Would Result From Its Application" And Their Related Allegation That "If The Impact Of Those Rates Is Evaluated, It Is Clear That They Are Unjust And Unreasonable."

In their Brief on Exceptions, at 23-37, Southern Parties raise eight basic arguments in support of their claim that the I.D. in this case would establish rates that are not "just and reasonable" within the meaning of Section 205(a) of the Federal

Power Act, 16 U.S.C. § 824d(a). As discussed below, these contentions are wholly without merit, and indeed most were already considered and disposed of by the Administrative Law Judge for sound reasons, as set forth in the I.D.

1. The I.D.'s Requirement That Southern Parties Make A Compliance Filing Showing The Necessary Rate Calculations.

Southern Parties lead off their attack on the Administrative Law Judge's I.D. in this case with the allegation that, by failing to quantify the precise rates that result from the application of the net incremental cost methodology, the I.D. somehow neglected to fulfill a key legal requirement of assuring that the rates will be "just and reasonable." (Southern Brief at 23.) This is, frankly, an exceptionally weak line of argument. Although the I.D. did not list the precise rates Southern Parties will be authorized to charge, this is unexceptionable. On the contrary, it is standard practice in rate proceedings for the Commission to rely on a subsequent *compliance filing* by the regulated company, as the I.D. contemplates (<u>*see*</u> I.D., *mimeo* at 35 (ordering paragraph)), to set forth the precise rates that result from a decision on the merits.[4/]

[4/] The Commission's practice of approving a particular rate *methodology* in a decision, while requiring the regulated company to make a subsequent *compliance filing* where the precise rates are shown, is so well established as to hardly require case citations. Nonetheless, some recent examples of this practice may be found in the following Commission decisions: *SFPP, L.P.*, Opinion No. 435-A, 91 FERC ¶ 61,135, at 61,521 (2000); *Consumers Energy Co.*, Opinion No. 429-A, 89 FERC ¶ 61,138, at 61,397 (1999); *American Electric Power Serv. Corp.*, Opinion No. 440, 88 FERC ¶ 61,141, at 61,465 (1999); *Detroit Edison Co.*, Opinion No. 439, 88 FERC ¶ 61,070, at 61,166 (1999); *Maine Pub. Serv. Co.*, Opinion No. 434, 85 FERC ¶ 61,412, at 62,568 (1998).

The Administrative Law Judge did not err in requiring Southern Parties to show the resulting rates in a compliance filing. The I.D. contains precise citations to all of the testimony and exhibits upon which these rate calculations will need to be made. (*See* I.D., *mimeo* at 28-29.)

In their Brief on Exceptions, Southern Parties contend that the resulting Availability Payments will total approximately $4.4 million per year, which they allege is only 2.7 percent of the settled AFRR. (Southern Brief at 24.) The Signatories believe these figures to be incorrect. Rather, the correct amount of the Availability Payment, based on the exhibits in this case, is actually $5,017,214 per year, which equals approximately 3.18 percent of the AFRR. This rate calculation is shown, along with citations to the supporting exhibits, in Appendix 1 hereto.

However, the Commission at this time need not concern itself with any quibbles over the precise rate levels; the appropriate time to reconcile any differences in the rate computations will be *after* Southern Parties make their compliance filing. For now, it is sufficient to note that the Administrative Law Judge committed no error, nor prejudiced Southern Parties in any way, by approving the net incremental cost *methodology*, with citation to the record exhibits where the incremental cost calculations were performed by the PG&E witnesses. (I.D., *mimeo* at 28-29.) He appropriately required Southern Parties to perform the resulting *rate computations* in a subsequent *compliance filing*. (*See id.* at 35 (ordering paragraph). This is entirely in accordance with normal Commission practice.

2. "Confiscation."

Southern Parties contend that the I.D. fails to honor the established legal doctrine that it is "the impact of a rate, and not the methodology used to design that rate, that must ultimately be found to be just and reasonable." (Southern Brief at 23-24, and 26-28, *citing, inter alia, Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310 (1988), and *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944).) This is, as Southern Parties say, "hornbook law." (*Id.* at 23)

There is no merit to Southern Parties' arguments that the rates are in any sense unfair to them as investors. As the I.D. demonstrates, the approved rates will fully compensate Southern Parties for all of the net out-of-pocket and opportunity costs they incur as a result of their obligations under the RMR Agreements. (*See* I.D., *mimeo* at 28-29.) Importantly, the rates also will be fair to consumers, by not requiring them to subsidize Southern Parties' participation in competitive energy and ancillary services markets where Southern Parties have been authorized to sell the output of their California power plants.

Citing *Hope* and other related authorities, Southern Parties argue that RMR rates based on the net incremental cost methodology "clearly fall outside the zone of reasonableness and are confiscatory." (Southern Brief at 27.) Southern Parties base this argument on the erroneous claim that the rates they will be able to charge, if the Commission affirms the I.D., will deprive them of "a reasonable opportunity to recover [their] cost of service, including a return on and of [their] fixed costs . . . ." (*Id.* at 26 (citations omitted).)

This claim, of course, completely overlooks the fact that Southern Parties are primarily engaged in merchant sales of energy and ancillary services. They do so under a grant of authority from this Commission allowing them to make such sales at market-based rates and to enjoy potentially unlimited profits thereby. The Administrative Law Judge persuasively disposed of Southern Parties' reliance on traditional cost-based ratemaking principles for the RMR Availability Payment, in the following two paragraphs in the I.D., which warrant quotation in full:

> Southern Parties essentially argue for the best of both ratemaking worlds: cost-based (regulated) security coupled with market rate (competitive) opportunity. On one hand, Southern parties propose to guarantee themselves more than 75 percent of the RMR units' composite AFRR by allocating it to ISO availability via the FOP. Exh. SOU-6. On the other hand, they propose to keep all revenues earned from market-based rate sales of energy/ancillary services. Exh. SOU-1, at pp. 14-16; Exh. S-12, at pp. 11-12. The result would be a 75 percent transfer of the risk associated with Southern Parties' RMR unit acquisitions to the ISO (ultimately, to California consumers) coupled with Southern Parties' retention of all benefits associated with the acquisitions. This scenario is inappropriate for numerous reasons.
>
> First, even in a pure cost-of-service environment, *Hope* and *Carolina Power* do not unconditionally guarantee return of/on investment. Those cases stand for the more limited ratemaking principle that rates must provide an *opportunity* for return of/on investment. *Hope*, 320 U.S. at 603; *Carolina Power*, 860 F. 2d at 1098. Southern Parties have been provided that opportunity through the authority to charge market-based rates for energy/ancillary services. The return requirements articulated in *Hope* and *Carolina Power* therefore have been satisfied. There is no legitimate basis for providing a supplemental opportunity for return of/on investment, let alone the supplemental

> *guarantee* Southern Parties propose. Any such supplement would constitute an inappropriate subsidy to Southern Parties' participation in the competitive markets for energy/ancillary services. Second, Southern Parties' proposal is inequitable. It exhibits utter lack of proportionality between potential reward-- in the form of opportunities to earn market-based revenues from sales of energy/ancillary services-- and risk– in the form of sunk cost responsibility. Southern Parties exacerbate this lack of proportionality by obscuring their RMR units' dominant function as competitive energy/ancillary service providers. RMR availability obligations are merely the incidental local market power mitigation mechanisms which enable RMR units to reap the potential benefits of their dominant function. Third, Southern Parties' proposal blurs the fundamental distinction between RMR unit operation under Conditions 1 and 2 of the RMR Agreements. Only RMR Agreement Condition 2 operations legitimately fall within the purview of *Hope* and *Carolina Power*. But while RMR unit operation under Condition 2 guarantees AFRR recovery, it also requires all market revenues derived from energy/ancillary service sales to be credited to the ISO.

(I.D., *mimeo* at 24-25 (footnotes omitted).)

As the United States Supreme Court stated in *Duquesne*, one of the cases cited by Southern Parties, "the impact of certain rates can only be evaluated in the context of the system under which they are imposed." *Duquesne*, 488 U.S. at 314. Here, the Administrative Law Judge properly analyzed the net incremental cost methodology in the context of the market-based rate authority Southern Parties sought and obtained for their sales of energy and ancillary services. Under those market-based rates, Southern Parties can enjoy potentially unbounded profits. Under *Duquesne*, it is not "confiscatory" to set RMR Availability Payments for these same plants at a cost-based level, pursuant to the net incremental cost methodology.

The I.D. also found that "Southern Parties' ability to elect Condition 2 status, moreover, obviates any potential for the confiscation which Southern Parties allege." I.D., *mimeo* at 25, n. 24. Under Condition 2, the owner of a unit incapable of earning an adequate return in the market can elect to be paid its full AFRR by the ISO under the RMR Agreement, subject to a requirement that the owner credit all market revenues back to the ISO, but the owner foregoes the prospect of participating in market activity. Southern Parties complain, however, that because the RMR Agreements approved in the April 1999 Stipulation only allow an owner to switch to Condition 2 *prospectively*, and upon giving proper notice, then Southern Parties cannot be made whole for any losses they might suffer in the prior period, commencing June 1, 1999, while they were under Condition 1 status. (Southern Brief at 28.)

First, it must be noted that availability of "Condition 2" is not necessarily required in order to serve as a backstop against unlawful confiscation. Having voluntarily elected to purchase a power plant and to seek market-based rate authority for selling its output, a power plant owner is not assured any return on or of its investment. In competitive markets, a bad investment can mean a loss of the investment. So long as the choice to buy the plant and enter the competitive market was freely made, as it was by Southern Parties here, and so long as the Southern Parties can, in fact, collect market-based rates, then *Hope* and the other precedents cited by Southern Parties do not come into play at all.

Second, there is no reason, in any event, for the Commission to decide this "Condition 2-as-backstop" issue in the instant case. Southern Parties agreed to the April 1999 Stipulation, which contained a complex balance of benefits and burdens among the many participants. One of the agreements made in that Stipulation was that RMR owners could elect Condition 1 or Condition 2 status at the outset. Southern Parties elected Condition 1 for most of their units. The parties also agreed in the April 1999 Stipulation to reserve for litigation the issue of the level of Availability Payments for Condition 1 units under the new RMR Agreements, and they further agreed that the outcome of that litigation would be retroactive to June 1, 1999, the effective date of the Stipulation. Having accepted this package deal, Southern Parties today cannot claim any constitutional or statutory right to protection against a less-than-robust market outcome in the period from June 1999 to the present. Moreover, Southern Parties have provided absolutely no evidence in any event to suggest that they did, in fact, experience a less-than-robust market performance in sales of energy and ancillary services, and there is no reason to believe they did.

A final point that must be recognized, in response to Southern Parties' "confiscation" argument, is that it is virtually undisputed on the record of this case that RMR Availability Payments based on the owner's net incremental cost are *fully compensatory* of all the owner's out-of-pocket costs and net opportunity costs imposed by the RMR Agreements. As the Administrative Law Judge found:

> The record establishes that each of the Joint Parties, Staff, CPUC and EOB net incremental cost compensation proposals would reimburse Southern Parties for all costs – including fixed costs, variable costs and reasonably identifiable opportunity costs-- associated with their RMR unit availability obligations. The record also establishes that each proposal ensures that any RMR unit rendered uneconomic by net incremental cost compensation remains viable through "going forward" cost reimbursement. Most important, the record establishes that compensating Southern Parties' RMR availability obligations at net incremental cost does not deprive them of any significant opportunity to participate in the competitive markets for energy/ancillary services or to maximize the financial rewards associated with that participation. The record therefore is conclusive that compensating Southern Parties' RMR availability obligations at net incremental cost would not unnecessarily disadvantage their participation in the competitive markets for energy and ancillary services.

(I.D., *mimeo* at 25-26 (footnotes and record citations omitted).)

3. "Revenue Shortfall."

Southern Parties complain that the net incremental cost methodology approved in the I.D. will leave them with a "shortfall" of over $80 million per year relative to the settled AFRR. (Southern Brief at 24-25.) According to a calculation in the Southern Brief, the combination of the Availability Payments authorized by the I.D., plus the revenues Southern Parties will earn in competitive sales of energy and ancillary services, will be more than $80 million per year below their AFRR. (*Id.*) This is so, Southern Parties argue, because, "even if Southern Parties' expected annual revenues from all other sources [are] taken into account, the additional revenues are expected to be no greater than $77 million – less than one-half of the stipulated $158.8 million AFRR." (*Id.* at 24.) Southern Parties cite a $77 million-per-year "prediction of market revenues" they say was sponsored by ISO witness Brian Theaker. (*Id.*, *citing* Tr. at 550:19-552:4.)

What Southern Parties have failed to disclose in their Brief on Exceptions, however, are their own, internally-prepared revenue forecasts. (The Southern Parties' forecasts are contained in Exhibits PGE-26 and PGE-27 (Protected).) Because Southern Parties' revenue forecasts, at their insistence, are in the sealed portion of the record, and because Signatories wish this Brief Opposing Exceptions to remain in the public record, Signatories are constrained to not discuss the specifics of Southern Parties' revenue forecasts here.

As for the revenue forecast sponsored by ISO witness Theaker, he made it clear that his forecast was intended to be a conservative estimate, and was offered merely to serve as a screening device to identify which of Southern Parties' units, if any, might not be able to cover its going-forward costs through market sales of energy and ancillary services. (*See* Ex. ISO-6 (Theaker-Rebuttal), at 16:3-8.) The conservatism in Mr. Theaker's revenue forecast was confirmed by actual market data showing that the forecast was substantially and consistently below actual revenue levels for prior periods for which data were available. (Ex. PGE-3 (Weingart-Direct), at 28:1-30:13; Ex. PGE-10; Ex. ISO-6 (Theaker-Rebuttal), at 15:12-22.) As the I.D. concluded, "the record confirms that going forward costs were calculated based on conservative estimates of anticipated market revenues." (I.D., *mimeo* at 29.) Indeed, when confronted with Southern Parties' own revenue forecasts at the hearing – forecasts which Southern Parties had attempted to withhold, and which they reluctantly produced in discovery only one day before the start of hearings – Southern Parties' corporate vice president, Robert Lamkin, frankly admitted that Mr. Theaker's revenue forecast was indeed "in the ballpark." (Tr. at 804:4-8 (Protected.))

In light of all this evidence, it is disingenuous for Southern Parties now to allege an $80 million per year revenue "shortfall." Suffice it to say that Southern Parties' cries of looming impoverishment are highly misleading.

4. Southern Parties' Greedy "Allocation" Proposal.

Southern Parties fault the I.D. for declining to adopt their proposal to use what they characterize as a traditional cost allocation approach to set the Availability Payment. (Southern Brief at 25, *citing* Section V.H of the Southern Brief, at 77-86.) But the allocation method favored by Southern Parties would have forced the ISO, and hence PG&E ratepayers, to pay for 77 percent, on a combined basis, of the settled AFRR for Southern's three California power plants (*97 percent* in the case of the Potrero Plant in San Francisco). The total ISO Availability Payment to Southern Parties under this scheme would have been approximately $121 million per year. The Administrative Law Judge persuasively reasoned that Southern Parties were seeking, in effect, "the best of both ratemaking worlds," and he properly declined to impose on PG&E and its ratepayers the huge subsidy Southern Parties proposed. (*See* I.D., *mimeo* at 23-25.) He found that Southern Parties can and should be expected to recover their investment in the competitive markets for energy and ancillary services:

> Since Southern Parties sought and were granted authority to charge market-based rates for their RMR unit energy and ancillary services (Exh. SOU-13, at p. 1; Exh. SOU-14, at p. 2), it would be antithetic to California's competitive paradigm to permit them to guarantee significant return of/on RMR unit investment through the FOP. It also would be antithetic artificially to suppress Southern Parties' RMR unit acquisition risk by transferring over 75% of that risk to the ISO/California consumers through the FOP. Any such transfer, moreover, not only would be inequitable to California consumers, but also would grant Southern Parties a considerable competitive advantage over other California energy/ancillary service providers by subsidizing Southern Parties' energy/ancillary service merchant operations. Exh. PUC-1, at pp. 17, 26-28; Tr. 701-04. Finally, it would be disingenuous to reward (indirectly through the FOP) the local market power that imposing RMR obligations on Southern Parties was intended to mitigate in the first place.

(I.D., *mimeo* at 27.)

5. "A Crippling Refund Obligation."

Southern Parties complain that the rate methodology approved in the I.D. will "impose a crippling refund obligation" of approximately $91 million, plus interest, based on the difference between the approved rates and the interim rates Southern Parties have been charging since June 1, 1999. (Southern Brief at 25-26.) They characterize this as "an onerous, unwarranted, and unfair penalty to impose on the Southern Parties on the basis of a ratemaking methodology that has never been used before and that provides a result that is more onerous tha[n] that proposed by any of the parties to the case." (*Id.* at 26.)

There is nothing inequitable or improper about making Southern Parties refund the excess amounts they have collected in rates. On the contrary, this is precisely the remedy Section 205(e) of the Federal Power Act, 16 U.S.C. § 824d(e), prescribes upon issuance of a merits decision approving rates at levels less than the rates the Commission has allowed to be placed into effect subject to refund. In this instance, Southern Parties themselves elected an interim Availability Payment equal to 50 percent of their AFRR. Southern Parties made this election as part of the April 1999 Stipulation. They did so with full knowledge that the reserved issue regarding "the appropriate level of the Fixed Option Payment under each revised RMR rate schedule" remained to be decided. Although testimony had not yet been filed on the reserved issue at the time Southern Parties elected a 50 percent of AFRR interim payment, they certainly knew or should have known that in litigation the consumer parties would advocate rates substantially below the interim rate level. This is especially true since, as the record in this case shows virtually without contradiction, the total out-of-pocket and net opportunity costs imposed by the RMR Agreements on the Southern Parties are a mere $5.1 million per year. Southern Parties cannot reasonably request a waiver of, or exemption from, their statutory refund obligation on the ground of hardship, surprise, or any other reason. Indeed, to accept Southern Parties' argument here would be to undercut the Commission's ability to require refunds in other circumstances as necessary to make consumers whole for past over-collections.

6. Alleged Restriction on Market Participation.

In the Brief on Exceptions at 28-32, Southern Parties merely repeat the arguments, discussed above, alleging that the rate levels set in the I.D. are not "just and reasonable" from their perspective as investors under *Hope* and related authorities. The only point warranting any further discussion is Southern Parties' assertion that their market-based rate authority for sales of energy and ancillary services "specifically <u>does not apply</u> to those hours in which the Southern Parties provide service to the ISO under the RMR Agreements." (*Id.* at 29 (emphasis in original).)

This assertion creates the misimpression that the ISO somehow has the power under the RMR Agreements to force the RMR owner out of the market during hours when the owner otherwise might choose to participate in market sales of energy and ancillary services. In fact, however, as made clear in the "Joint Stipulation of the Procedural History and Factual Background" of this case (which is reproduced verbatim in the I.D.), the RMR Agreements do no such thing. Rather, the RMR Agreements contemplate that the ISO will require additional generation by RMR generating units only to the extent that their level of market participation is not sufficient to meet the ISO's reliability needs. In other words, the ISO looks to the "market first" for meeting its reliability needs, before calling upon RMR units. The Joint Stipulation (which Southern Parties themselves co-sponsored) describes this aspect of the RMR Agreements as follows:

> The Southern Parties are engaged in sales of energy and ancillary services in one or more of the competitive, bid-based markets available to market participants in California (including the PX), or through bilateral contracts. In most instances where the Southern Parties are engaged in market transactions at times when a unit is needed to deliver energy for reliability purposes, the market transaction will (in whole or in part) satisfy the ISO's reliability needs and the ISO will not need to change the unit's output to deliver energy in accordance with the RMR Agreement, although this is not always the case. The ISO and the other parties refer to this aspect of the RMR Agreements as the "Market-First" principle.

(I.D., *mimeo* at 6 (incorporating verbatim the text of the Joint Stipulation).)

If Southern Parties are suggesting that they can charge market-based rates only in the hours in which they do not receive an RMR dispatch notice from the ISO, the suggestion is manifestly false. The record makes clear that, in satisfying RMR calls, Southern Parties can, and do, charge market-based rates to the extent they expect such rates to exceed the variable cost-based rates provided in the contract. Only when they expect market-based rates to be lower than the cost-based contract rates will Southern Parties opt for the latter in meeting their RMR obligations. In the rare circumstance in which the RMR unit may be called out-of-market – in particular, when it is called for ancillary services under the RMR Agreement, and thus may be precluded from generating and marketing energy – the owner's opportunity costs are fully reimbursed under the net incremental cost methodology.[5/]

[5/] Amendment 26 to the ISO Tariff, which recently was approved by the Commission, changed the timing of Day Ahead RMR Dispatch Notices to ensure that energy needed for reliability purposes would be scheduled through the market and would no longer displace other scheduled market energy.

(Continued …)

7. "Undue Discrimination."

Southern Parties argue at some length that the rates established by the I.D. in this case would be unduly discriminatory in comparison to the Availability Payments other California RMR owners will receive under a recent series of Commission-approved (or pending) settlements. (Southern Brief at 32-37.) They complain of a "gross disparity" in rates, and they particularly emphasize the fact that PG&E's Humboldt Bay plant is receiving an Availability Payment equal to 50 percent of its $11 million AFRR under the terms of one such settlement. (*Id.* at 36-37.)

The simple response to this argument is that Southern Parties themselves elected to pursue litigation, rather than settle, in this case. All the other RMR owners elected to settle. In choosing to litigate, Southern Parties accepted the risk of a litigation outcome worse than what they and other owners were offered in settlement. They deserve no sympathy now, because of their own choice to *not* settle.

Moreover, the Commission and the Courts have long disfavored claims of "discrimination" based on comparisons of the type Southern Parties are now making

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See California Independent System Operator, 90 FERC ¶ 61,345 (2000). As of June 1, 2000, the ISO now issues Day Ahead Dispatch Notices in advance of the PX Day Ahead Market. The RMR Owner chooses, for each separate hour of the Dispatch Notice, whether to participate in market transactions or accept a cost-based payment specified by the RMR contract for the energy. If the Owner chooses to participate in the market, the only restriction on its bidding is a requirement that energy not scheduled through the Day Ahead market be bid at zero into subsequent markets. Thus, the Owner still has the option to participate in the market in hours when it expects prices to be higher than its variable costs, and to fall back on the contract payment when it expects market prices to be low. *See id.*, 90 FERC at 62,140.

between litigated rates and settled rates. As the United States Court of Appeals for the District of Columbia Circuit has recognized:

> [S]ettlements promote market stability and reduce litigation over rate filings under the Federal Power Act. As FERC has noted, settlements would be severely discouraged, if not eliminated, if any resulting price disparities among customers were considered unlawfully discriminatory within the meaning of section 205(b). When a settlement is reached in good faith, by means of proper conduct by the parties, and when the resulting rate disparity is not unduly burdensome to a customer group, a rate difference caused by a private settlement may survive the anti-discrimination mandate of section 205(b).

Cities of Bethany, et al. v. FERC, 727 F.2d 1131, 1139 (D.C. Cir. 1984), *citing Delmarva Power & Light Co.*, 6 FERC ¶ 61,084 at 61,162 (1979).

The Commission's ruling in the above-cited *Delmarva* case warrants an extensive quotation, because it completely disposes of the discrimination argument Southern Parties are raising here:

> There will always be a disparity in rates during the pendency of a proceeding where one class of customers settles and the other class does not. The factual difference extant in every such case to justify the disparity in rates will be the choice of one class not to litigate and the choice of the other class to reject a settlement offer and incur the risks of litigation. Here the Municipals have chosen to incur the risk of litigation . . . . The Cooperatives on the other hand have chosen to settle with the Company at a rate level which they find acceptable, subject, of course, to the Commission's approval.
>
> As [*Public Service Co. of Indiana, Inc. v. FERC*, 575 F.2d 1204 (7th Cir. 1978), *Town of Norwood v. FERC*, 587 F.2d 1306 (D.C Cir. 1978), and *Cities of Altus, et al. v. FERC*, No. 77-1548 (D.C. Cir., October 23, 1978 (unreported)] indicate, if there are factual differences to justify the disparity, then undue discrimination does not exist. In those cases the focus of inquiry was the contract formation

> stage. In this case the focus is on the settlement which has been negotiated with the Cooperatives. In its answer to the Municipals, Delmarva has stated that a settlement offer containing "essentially similar terms," including a 35.7% reduction from the filed rate increase, was extended to the Municipals and was refused by them. The statement is not disputed in the Municipals' reply. . . . Under these circumstances we conclude that no undue discrimination within the meaning and context of Section 205(b) of the Act will be created if the settlement rates applicable to the Cooperatives are placed in effect during the pendency of this proceeding.
>
> The Municipals have requested, in essence, that their rate increase be rolled back to a level which places them in a comparable basis with the Cooperatives. They seek to justify such request on an asserted absence of factual differences and, further, on the basis that the rate level provided in the settlement "…must in the end be considered the maximum rate Delmarva could ever seek to obtain." It is clear that our acceptance of this argument would severely inhibit any incentive to settlement of electric rate cases, a course we encourage whenever reasonable accommodations can be achieved. No utility company could afford to risk anything less than a full and complete settlement with all its customers, while individual customers would have no incentive to settle since each could feel secure that the Commission would simply order an "interim" rate giving them all the rate level benefits of a settlement, but none of the burdens of having to negotiate and agree to a settlement.
>
> We reject the claim that the settlement which has been negotiated in itself sets a ceiling on the rate to be charged the Municipals. To the contrary, we affirm our determination that the rate level approved in this case for application to the Municipals will be that which is determined at the conclusion of this proceeding to be just and reasonable under Section 205(a) and otherwise consistent with the requirements of the Act.

Delmarva, *supra*, 6 FERC at 61,161-61,162 (footnotes omitted).

In this case, Southern Parties in effect are claiming that the settlements reached by the other RMR owners should be treated, not as a ceiling (as the Municipals asserted in *Delmarva*), but as a floor. This is an even less sympathetic position than the Municipals took in *Delmarva*. Here, Southern Parties are the *rate applicants*, not a customer, and they are complaining about discrimination because of rate settlements reached by *other* rate applicants (*viz.*, the other RMR owners). Like the Municipals in *Delmarva*, Southern Parties base their claim of discrimination solely on a comparison with the rates achieved by another group of parties who elected to settle rather than litigate. As in *Delmarva*, Southern Parties cannot allege – and they do not allege – that they somehow were singled out and *not* offered settlement terms comparable to the settlement terms the other RMR owners agreed to. The simple fact is this: Southern Parties chose to litigate, while the other RMR owners chose to settle. Under *Delmarva* and other longstanding judicial and Commission precedents, Southern Parties' discrimination claim is baseless and should be dismissed.

In any event, the comparisons Southern Parties seek to make to PG&E's Humboldt Bay plant are unsupported. Southern Parties introduced no evidence at hearings that would allow a proper comparison of, for example, the heat rates and other operating characteristics of the Humboldt Bay units with Southern Parties' units, or the extent to which their respective capital investments have been depreciated. *See* Tr. at 625:23-25 (Weingart) (noting that the Humboldt Bay units were built in 1949, are not very economic, and are not expected to earn much in the way of market revenues). Thus, the various numerical comparisons Southern Parties make between the Humboldt Bay units and their own units (Southern Brief at 36) are meaningless at best, and very possibly misleading. They deserve no weight in these proceedings.

B. Signatories' Response To Southern Parties' Allegation That The Initial Decision Erred In Concluding That RMR Obligations Are Not A Discrete Product Or Service, And That The RMR Agreements Are Not Analogous To "Capacity" Contracts.

Southern Parties have argued that the service they provide to the ISO pursuant to the RMR Agreements constitutes "a unique product" analogous to a traditional capacity product. (Southern Brief at 37-49.) They claim the Administrative Law Judge erred in concluding that RMR units do not produce a capacity-type product. Based on their analogy to capacity-type contracts, Southern Parties have urged that more than three quarters of the settled fixed cost of their three California power plants (77 percent of AFRR, on a combined basis; 97 percent of AFRR in the case of the Potrero plant in San Francisco) be allocated to the ISO, and collected via the Availability Payments under the RMR Agreements. These assertions do not withstand scrutiny, as the Administrative Law Judge concluded. (*See* I.D., *mimeo* at 19-22.) Southern Parties have given no basis for disturbing the I.D.'s finding that the ISO does *not* obtain a "capacity" product from Southern Parties under the RMR Agreements. It follows that the ISO should not pay a capacity-based payment for Availability.

1. The Administrative Law Judge's Conclusion Rejecting as "Discredited" Southern Parties' Capacity Contract Analogy.

Although Southern Parties contend that the record "conclusively" supports their position on the key issue of whether the RMR Agreements are a form of capacity contract (Southern Brief at 38), after reviewing all the evidence the Administrative

Law Judge saw it differently. Indeed, the Administrative Law Judge found that this theory had been "discredited" by the evidence in this case. (I.D., *mimeo* at 23.)

The Administrative Law Judge's review of the record evidence on this issue is both instructive and correct:

> The record demonstrates that the similarities Southern Parties cite to support the capacity reservation analogy are superficial. First, Southern Parties' attempt to analogize RMR availability obligations to traditional capacity reservations ignores a fundamental difference between the two: whereas a traditional firm capacity service provider is restricted from selling output (e.g., energy/ancillary services) to third parties in the event the capacity purchaser calls on the output, Southern Parties' RMR availability obligations impose no such restriction. Exh. PGE-17, at pp. 5-6; Exh. PGE-18, at pp. 4-6; Exh. ISO-5, at pp. 5-8; Tr. 933-35. Moreover, in contrast to traditional (cost-based rate) firm capacity service providers, Southern Parties may sell their RMR unit outputs at market prices. Exh. PGE-17, at pp. 5-6; Exh. PGE-18, at pp. 5-6; Exh. ISO-5, at p. 7; Exh. S-12, at p. 11. Southern Parties therefore retain virtually all economic benefits of their RMR unit generating capability whenever market prices exceed variable operating costs. Exh. ISO-5, at p. 7. This characteristic further distinguishes Southern Parties' RMR unit availability obligations from traditional firm capacity reservations. Generating unit owners normally may resell unscheduled energy under traditional firm capacity contracts, but they are required to credit proportionate revenues against any fixed costs allocated to the capacity contract holder(s). Exh. S-12, at pp. 18-19. . . . The RMR Agreements at issue do not require Southern Parties to credit any market revenues back to the ISO. It follows that Southern Parties' attempt to analogize RMR unit availability obligations to traditional firm capacity reservations does not support a conclusion that RMR obligations constitute a discrete capacity product or service.
>
> The same holds true for an analysis of RMR obligations' fundamental purpose. That purpose indisputably is to mitigate the potential for RMR unit owners to exercise local market power at times when the units are essential to transmission grid reliability. Exh. SOU-1, at pp. 13-14; Exh. PGE-17, at pp. 4-5; Exh. SCE-2, at pp. 21-22; Exh. ISO-1, at p. 7; Exh. S-1, at pp. 9-10; Exh. PUC-1, at pp. 4-5; Exh. EOB-

> 1, at p. 8. . . . As previously observed, that potential would not exist had the RMR unit owners not sought and been granted authority to charge market-based rates for the energy/ancillary services provided by the units. Southern Parties expressly acknowledged this fact in their applications for authority to charge market-based rates for the RMR units at issue in this proceeding (Exh. SOU-13, at p. 1; Exh. SOU-14, at p. 2), which were approved by letter order issued March 31, 1999 in Docket Nos. ER99-1833-000, ER99-1841-000 and ER99-1842-000. Exh. SOU-15. It follows that while RMR obligations may not rise to the level of *quid pro quo* for RMR unit authority to charge market-based rates for energy/ancillary services, the obligations clearly constitute necessary conditions precedent for such authority. . . . In the absence of these conditions, RMR unit owners' market-based rate authority would permit them to withhold – or threaten to withhold – essential transmission grid support, thereby artificially inflating the price of that support. Exh. SD-2, at pp. 12-14; Exh. ISO-5, at pp. 3-4; Exh. PGE-18, at p. 4; Exh. SOU-1, at p. 13. RMR obligations, then, are not properly characterized as a discrete product or service. Instead, they 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 the generators' ability to exploit local market power in limited circumstances.

(I.D., *mimeo* at 20-22 (footnotes omitted; case citations omitted; emphasis in original).)

2. Testimony Supporting The Administrative Law Judge's Conclusion That The RMR Agreements Are Not Analogous To "Capacity" Contracts.

A brief review of the record evidence only serves to reinforce the I.D.'s soundly reasoned conclusion that the RMR Agreements are not truly analogous to "capacity" contracts. The ISO, for example, presented testimony by Dr. Hildebrandt, an economist and the Manager of Market Monitoring Systems in the ISO's Department of Market Analysis, who noted a number of important distinctions between the RMR Agreements and "capacity" contracts. (Ex. ISO-5 (Hildebrandt-

Rebuttal), at 6:11 - 10:8.) He explained that, because the RMR owner can sell energy and ancillary services to any willing purchasers, the RMR owner, in contrast to the seller under a capacity contract, "retains virtually all the economic benefits whenever the option to generate is 'in the money,' that is, whenever market prices exceed the RMR Unit's variable operating costs." (Ex. ISO-5 (Hildebrandt-Rebuttal), at 7:8-11.) Dr. Pace, an economist who has testified before this Commission in numerous prior cases, likewise challenged as "completely inappropriate" Dr. Madian's analogy between the RMR Agreements and traditional capacity contracts. (Ex. PGE-17 (Pace-Rebuttal), at 5:15 - 6:6.) Richard Weingart, PG&E's director of generation and reliability strategy, outlined several key differences between the RMR Agreements and capacity contracts. (Ex. PGE-18 (Weingart-Rebuttal), at 3:16 - 7:7.) Other witnesses testified to like effect. (*See* Ex. PUC-1 (Kahlon-Direct), at 22:5 - 23:13; Ex. SD-2 (Ruff-Rebuttal), at 14:19.)

The testimony of these witnesses strongly supports the Administrative Law Judge's conclusion that the RMR Agreements are fundamentally different from capacity contracts. In a nutshell, the seller under a capacity contract loses the right to sell its output to third parties for its own benefit when that output is called for by the buyer. The seller under an RMR contract keeps that right, and, indeed may make such sales at market prices. As Dr. Pace observed, under the RMR Agreements, the RMR owner "retains the full 'capacity value' of the unit, as long as it is compensated for any opportunity costs imposed by RMR contract obligations." (Ex. PGE-17

(Pace-Rebuttal), at 5:25-27.) Similarly, Dr. Hildebrandt concluded that "[t]he RMR Agreement bears no meaningful resemblance to traditional power contracts for firm capacity." (Ex. ISO-5 (Hildebrandt-Rebuttal), at 6:13-14.)

3. Southern Parties' September 1999 Solicitation To Lenders, Confirming That The RMR Agreements Do Not "Impound Market Value From The Generators."

Although it is nowhere mentioned in Southern Parties' Brief on Exceptions, there is in the record of this case a document prepared by Southern Parties which directly disproves their assertion that the RMR Agreements must be treated as a form of capacity contract. The document is an informational memorandum Southern Parties provided to potential lenders in September 1999, in order to obtain financing of the three power plants at issue, along with other assets. Ex. PGE-30 ("Lender Memorandum"). Southern Parties strenuously resisted discovery of the Lender Memorandum until being ordered to disclose it on the very eve of hearings.[6/] The Lender Memorandum's description of the RMR Agreements not only parallels both the foregoing testimony and the I.D. in this case, it also contradicts Southern Parties' own testimony. The document states:

> It must be stressed that must-run status does not give the CAISO the right to impound market value from the generators. Except in certain real-time situations, the CAISO will call on must-run capacity only when the capacity has failed to enter the day-ahead

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6 / On Friday, March 17, 2000, the Administrative Law Judge granted PG&E's motion to compel production of the Lender Memorandum and other documents, which Southern Parties had refused to provide in discovery. Pursuant to the Judge's order, the subject documents were delivered to PG&E's counsel on Sunday, March 19, the day before hearings began.

> market through the normal bidding process. In fact, a market transaction can be substituted for any must-run call by the plant owner, as long as the plant generates its required amount. It must also be understood that must-run status does not mean that a unit must always run. It must always be available to run when called, within the limits set in the unit-specific RMR Contract.
>
> * * *
>
> Under Condition One, if the unit is not dispatched through the market, the CAISO may call upon a "must-run" unit to operate subject to committed amounts of yearly generation and a number of annual start-ups. In each call, the CAISO must request at least the minimum MW output of a unit necessary to maintain stable continuous operation of the unit. The CAISO will reimburse each must-run unit for variable expenses and start-up costs incurred during must-run operation. It is expected that such energy reimbursements will be at a rate higher than the then-current market clearing price ("MCP"), since must-run operation should be called upon only when MCP is lower than the energy cost of the unit. Must-run operation is therefore not an impoundment of economic opportunity. The owner of the Condition One unit is able to bid into the PX or participate in other markets, and the owner will receive all revenues and bear all costs associated with such voluntary market participation.

(Ex. PGE-30 (Southern Lender Memorandum), at 56-57.)

The Lender Memorandum completely undermines Southern Parties' argument here that the RMR Agreements confer a "capacity" right upon the ISO. In the Lender Memorandum, Southern Parties accurately represented to their potential lenders that the RMR Agreements do not result in "an impoundment of economic opportunity." The document has significant evidentiary value, because it was used by Southern Parties to solicit financing for the three plants at issue here, among other assets.

At the hearing, Southern Parties' two witnesses who testified about the Lender Memorandum (Dr. Madian and Mr. Lamkin) offered conflicting explanations. Dr. Madian testified that he had not seen the Lender Memorandum until it was produced in discovery the day before the hearing began. He actually testified that he believed the Lender Memorandum's statement that the RMR Agreements do not give the ISO "the right to impound the market value from these units" was not a true statement. Tr. at 683:19-23. Dr. Madian went on to characterize the Lender Memorandum as a "sales document," concluding dismissively that "there is something in the world of sales which is called puffery . . . ." Tr. at 687:24 - 688:2.

The next day, Mr. Lamkin testified. He was the corporate officer responsible for creating the pertinent portions of the Lender Memorandum before it was sent to potential lenders. Mr. Lamkin disputed Dr. Madian's testimony about the Lender Memorandum, saying that his view was "quite a bit different than what [Dr. Madian] expressed or hypothesized yesterday." Tr. at 766:16-17. Mr. Lamkin offered a new explanation. He testified that the Lender Memorandum's statement that RMR Agreements do not give the ISO "the right to impound market value from the generators" should have been qualified by the additional phrase "except in certain real-time situations." That phrase actually appears at the beginning of the next sentence, and, according to Mr. Lamkin, was misplaced in the final preparation of the Lender Memorandum. Mr. Lamkin testified that, "with that grammatical fix" the document "makes perfect sense." Tr. at 767:24 - 768:1.

Ultimately neither of these witnesses offered any explanation that could shake the impression that Southern Parties had represented one thing to potential lenders, and something very different in their testimony before this Commission. This evidence further buttresses the Administrative Law Judge's conclusion that the RMR Agreements cannot fairly be deemed the equivalent of "capacity" contracts, as Southern Parties alleged.

4. Southern Parties' Misplaced Reliance On Prior Commission Orders, And A Recent PG&E Rate Filing, For Its Assertion That The ISO Obtains A "Capacity" Right Under The RMR Agreements.

Southern Parties contend that prior Commission orders describing the RMR Agreements, as well as a recent rate filing in which PG&E is seeking to allocate its RMR costs among different classes of ratepayers, contradict the Administrative Law Judge's conclusion on this point. (Southern Brief at 38-42, *citing, inter alia, California Independent System Operator Corp.*, 90 FERC ¶ 61,345 at 62,135 (2000); and *California Independent System Operator Corp.*, 83 FERC ¶ 61,309 at 62,270, n.5 (1998), and *citing* PG&E rate filing in Docket No. ER00-2360-000 (filed April 28, 2000). Southern Parties particularly criticize PG&E, claiming that "PG&E is talking out of both sides of its mouth." (*Id.* at 41.)

The orders and the PG&E rate filing to which Southern Parties refer, however, merely recognized the undisputed fact that RMR service is separate and distinct from energy and ancillary services. Under the California paradigm, it is through sales of energy and ancillary services that power plant owners are expected to recover their investment in such assets. Neither the prior Commission orders cited by Southern Parties, nor the recent PG&E rate filing, can reasonably be said to support Southern Parties' argument that the RMR Agreements constitute a "capacity" commitment to the ISO.

5. Southern Parties' Allegation That The RMR Services They Provide To The ISO Are "Similar To, If Not Altogether The Same As, Capacity Products Offered In Other Deregulated Markets."

Southern Parties claim that their analogy between RMR Agreements and capacity contracts is supported by the fact that several other Commission-regulated regional transmission organizations in other regions besides California (the New England ISO, the New York ISO, and PJM Interconnection) operate "installed capacity" markets, which Southern Parties allege are separate from the markets for energy and ancillary services. (Southern Brief at 46-49, *citing, inter alia*, *ISO New England, Inc., et al.*, 91 FERC ¶ 61,311 (2000); *New York Independent System Operator*, 90 FERC ¶ 61,319 (2000); and *PJM Interconnection, L.L.C.*, 86 FERC ¶ 61,017 (1999).) Southern Parties claim that the existence of so-called "naked capacity" contracts, in particular the fact that there is a market for such contracts separate from energy and ancillary services markets, supports their argument that RMR Agreements must be treated as "capacity" contracts even though the RMR owner remains free at all times to sell energy and ancillary services separately. (Southern Brief at 46-47.) Southern Parties maintain that what is purchased in these three Eastern markets is "naked" capacity, which Southern Parties define as "capacity without any obligation to provide energy or ancillary services." (*Id*. at 47.)

In his hearing testimony in this case, Professor Joskow explained some of the important distinctions between these three Eastern ISOs and the California market, and in particular their reliance on installed capacity markets. (*See* Joskow, Tr. at 978:6-981:7.) The installed capacity market arrangements in New England, New York, and PJM are in no sense analogous to California's RMR Agreements. These three markets exist solely to enable market participants to meet a requirement set under tariff or contract, under which each participant meets its designated installed capacity requirement through ownership, purchase or both. The installed capacity requirement is used by these ISOs to address grid-wide — not location-specific — reliability concerns. Transactions in the three markets to which Southern Parties refer do not result in anything resembling the kind of bilateral capacity contract Southern Parties incorrectly claim is precluded for units under an RMR Agreement. Such transactions result only in satisfying a tariff obligation which has nothing to do with mitigating the local market power of individual generators.[7/]

[7/] Southern Parties also mistakenly equate the capacity credits obtained through installed capacity markets with "naked" capacity contracts, because, as the Commission previously has recognized, such contracts *do* require the seller to provide energy. *See Prior Notice and Filing Requirements Under Part II Of the Federal Power Act,* 65 FERC ¶ 61,081, at 61,506 n.2 (1993).

C. Signatories' Response to Southern Parties' Allegation That The Initial Decision "Erroneously Concludes that Compensation for RMR Services Above Net Incremental Cost Levels Reflects An Exercise of Market Power."

Although they acknowledge that "one of the important functions of the RMR Agreements is to mitigate the potential exercise of local market power" (Southern Brief at 50), Southern Parties contend that the I.D. improperly requires them "to strip out 'sunk costs'" from their RMR Availability Payments. Southern Parties allege that this is inconsistent with Commission precedent. (Southern Brief at 50-51, *citing Consumers Energy Co.*, 85 FERC ¶ 61,121, at 61,447 (1998); *Commonwealth Edison Co.*, 82 FERC ¶ 61,317, at 62,249 & n. 4 (1998); and *Delmarva Power & Light Co.*, 76 FERC ¶ 61,331, at 62,582 (1996), *reh'g dismissed*, 80 FERC ¶ 61,330 (1997).)

In each of the cited cases, the Commission granted market-based pricing authority for certain energy sales by traditional public utilities, but conditioned its authorization on the utility's commitment not to engage in market-based sales, but rather to continue cost-of-service-based sales, to customers in generation or transmission markets in which the utility still had market power. *See Consumers Energy*, 85 FERC at 61,447; *Commonwealth Edison*, 82 FERC at 62,249 n. 4 (citing prior cases); *Delmarva*, 76 FERC at 62,582. The foregoing cases are not at all analogous to the present situation. In those cases, the Commission allowed vertically-integrated electric utilities to make market-based sales of energy, but only in geographic markets where they did not have market power. Any sales by the utilities to their captive customers, meanwhile, remained under traditional, cost-of-service regulation, and indeed each of the subject utilities was specifically prohibited from engaging in sales at market-based rates to such captive customers. *See, e.g.*, *Delmarva*, supra, 76 FERC at 62,582.

Southern Parties seem to be suggesting that, when they respond to ISO dispatch notices, this activity is analogous to the energy sales the utilities made to their captive customers at cost-based rates in the foregoing cases. Because the Commission in those cases did not require any adjustment to the cost-based rates to "strip out sunk costs," Southern Parties assert that they, too, should be able to recoup sunk costs through the ISO's Fixed Option Payment under the RMR Agreements. (Southern Brief at 51.)

The flaw in this analogy is that it mischaracterizes the nature of Southern Parties' obligations under the RMR Agreement. Unlike a service involving the sale of energy or ancillary services, the RMR Agreement merely requires that the owner respond to ISO dispatch notices at times when the owner is otherwise not in the market. It ensures that the owner cannot withhold its unit from the market and thereby exercise its locational market power. As the I.D. in this case found, nothing in the RMR Agreement prohibits the owner from engaging in market-based sales, and to the limited extent the RMR dispatch notices may interfere with certain sales, the net incremental cost methodology fully compensates the owner for its opportunity costs; that is precisely its purpose. (*See* I.D., *mimeo* at 25-26.) The RMR obligations are triggered only when the owner, for whatever reason, chooses not to engage in a market-based sale of energy or ancillary services. There is no legitimate comparison between this market-power mitigation device and the Commission's prior decisions granting market-based pricing authority to vertically integrated utilities that remained subject to cost-of-service-based pricing for sales to captive customers.

In short, the fact that the Commission allows sunk costs to be recovered in sales of energy to captive customers is not a precedent for allowing Southern Parties to allocate sunk costs to the ISO under the RMR Agreements. As the I.D. concluded, it is essential to the competitive market design in California that Southern Parties be required to recover their sunk costs through market-based sales of energy and ancillary services, not from RMR Availability Payments. (I.D., *mimeo* at 26-27.)

Much more pertinent to the issues in this case is the Commission's decision in *TECO Power Services Corp.*, 53 FERC ¶ 61,202 (1990). Although Southern Parties have not mentioned *TECO* in their Brief on Exceptions, it was cited in the I.D. at 21. In that case, the Commission approved an allocation of fixed costs of a power plant between two firm sales customers: Tampa Electric Company (TECO's 100 percent-owned utility affiliate), and Seminole Electric Power Cooperative (an arms'-length, third-party customer). The Commission allocated 60 percent of the fixed costs of the new power plant to Seminole, and 40 percent to Tampa Electric.

Significantly, the Commission in *TECO* specifically required that any revenues earned from market sales of energy from the new power plant, at times when the output was not called upon by the two firm customers, had to be credited to the two firm customers in the same proportions as their fixed cost responsibility (*i.e.*, 60/40). Indeed, the Commission specifically *rejected* a plan to credit some of these market revenues to TECO Power Services, the utility's marketing affiliate, finding that "Power Services' retention of any revenue credits would appear to result in equity returns in excess of its costs and therefore be unjust and unreasonable." *TECO*, 53 FERC at 61,813. Accordingly, the Commission ordered the applicants "to revise the revenue credit provisions to increase Seminole's share to 60 percent, Tampa Electric's share to 40 percent, and exclude Power Services." *Id.*

In the instant case, Southern Parties propose to allocate 77 percent of their fixed costs (AFRR) to the ISO under the RMR Agreements, *while keeping 100 percent of the revenues they earn in market-based sales of energy and ancillary services*. The Commission's decision in *TECO* plainly forbids such a result, as the I.D. in this case recognized. (I.D., *mimeo* at 21.)

Southern Parties also cite the Commission's suspension order in *Duke Energy Moss Landing, LLC*, 83 FERC ¶ 61,318 (1998), *reh'g denied*, 86 FERC ¶ 61,227 (1999), *appeal dismissed sub nom. Duke Energy Moss Landing, LLC, et al. v. FERC*, No. 99-1141 (D.C. Cir., August 18, 1999). (Southern Brief at 51.) Their reliance on *Duke* is woefully misplaced. In that case, the Commission summarily rejected part of a proposed RMR rate schedule, where the owner sought to recover through RMR rates the premium it paid above book value for the generating units in question.

Contrary to Southern Parties' suggestion, the Commission in *Duke* did not rule that the remainder of Duke's fixed costs would be recoverable in the RMR Availability Payments; on the contrary, the Commission set that issue, along with other issues, for hearing. *See Duke,* 83 FERC at 62,306. The present case is now at the point where the *Duke* case would have been, had the *Duke* case not settled. Nothing in the *Duke* orders remotely suggests that an owner of RMR units should expect to recoup any part of its sunk costs in RMR rates. This is the very issue that now must be decided.

D. Signatories' Response to Southern Parties' Allegation That The Initial Decision "Is Contradicted by the Terms of the April 2 Stipulation and Agreement."

Southern Parties insist that the April 1999 Stipulation, which established the new form of RMR Agreement, and the RMR Agreement itself, preclude as a contractual matter the use of a net incremental cost methodology for computing Availability Charges. (Southern Brief at 52-59.) This claim does not withstand analysis, as the Administrative Law Judge cogently ruled:

> The April 2 Stipulation is . . . unavailing to Southern Parties. Essentially, they conclude that because the April 2 Stipulation dispositively settles AFRR, and the settled AFRR subsumes sunk costs, sunk costs necessarily must be included in the FOP. This conclusion, however, is a *non sequitur*. It ignores the fact that Southern Parties may elect to operate their units under RMR Agreement Condition 2. Exh. JT-2, at pp. 19-20. In that event, they would be entitled to recover AFRR in full-- including sunk costs. It therefore was necessary to quantify AFRR in the April 2 Stipulation. But it does not follow that the April 2 Stipulation entitles Southern Parties to recover sunk costs via the FOP during RMR Agreement Condition 1 operations. In contrast to RMR Agreement Condition 2 operations, which preclude Southern Parties from retaining market

> revenues (*id.*, at pp. 41-42, 59-60) and therefore require sunk cost recovery from the ISO, operations under Condition 1 provide the opportunity for sunk cost recovery through market rates for energy/ancillary services. There is no inconsistency between the April 2 Stipulation and compensating Southern Parties' Condition 1 RMR obligations at net incremental cost.

(I.D., *mimeo* at 32.)

Southern Parties argue that, because the incremental cost method results in a low Availability Payment, and because "non-performance penalties" under the RMR Agreements are expressed as a percentage of the Availability Payment, the I.D. "effectively reads the non-performance penalties out of the agreement." (Southern Brief at 58.) As the Administrative Law Judge said of the remainder of Southern Parties' argument based on the April 1999 Stipulation, quoted above, this is a *non sequitur*. The appropriate response is that, if the Commission believes Southern Parties may elect to breach their obligations under the RMR Agreements because of low penalties, then the Commission should consider increasing the penalties. There is no reason to raise the level of the Availability Payments above an otherwise appropriate level (*i.e.*, above the owner's net incremental cost), merely in order to increase the size of a potential non-performance penalty in the event of such a breach.

Also without merit is Southern Parties' argument that "Schedule F" in the RMR Agreements, which establishes a formula for determining the AFRR for the period commencing January 1, 2002 (the "Post Rate Freeze Period"), somehow gives the Southern Parties a right to sunk cost recovery during the period the rates at issue here will be in effect. (Southern Brief at 58-59.) For Condition 1 units, the Post-Rate Freeze AFRR, like the AFRR currently in effect, merely sets a ceiling on the level of fixed cost recovery the RMR owner can seek.

E. Signatories' Response To Southern Parties' Allegation That The Initial Decision Is "Contrary to the Southern Parties' Reasonable Commercial Expectations at the Time The Divestiture Transaction Was Negotiated."

The "bait and switch" issue (*see* Southern Brief at 59-66) has been fully addressed above, in the section of this Brief entitled "Rebuttal of Policy Considerations Claimed to Warrant Commission Review." To briefly summarize, the I.D. found absolutely no evidentiary support for Southern Parties' allegations, either in the "Offering Memorandum" PG&E prepared prior to the divestiture deal, or in the then-existing RMR contracts which at the time were pending before the Commission and still under discussion. (*See* I.D., *mimeo* at 31-32.) Further discussion of this issue is unnecessary.

F. Signatories' Response to Southern Parties' Allegation That The Initial Decision "Erroneously Concludes That The Net Incremental Cost Approach Provides The Proper Incentives For Investment in New Transmission and Generation Resources."

Southern Parties' argument regarding the appropriate price signal for resources that might replace existing RMR resources (*see* Southern Brief at 67-71) is discussed above, in the section of this Brief entitled "Rebuttal of Policy Considerations Claimed to Warrant Commission Review." In brief summary, the I.D. found on the basis of undisputed testimony that basing RMR Availability Payments on the owner's net incremental cost sends the appropriate price signal for replacement resources. The much higher, consumer-subsidized levels proposed by Southern Parties would lead to inefficient investments. Southern Parties' own witness testified to this effect, along with a number of witnesses for the consumer parties. Thus, the record on this issue is actually uncontested. Accordingly, there is no basis for Southern Parties' argument that a higher Availability Payment level is needed to stimulate socially beneficial investment in new generation and transmission resources that could replace existing RMR generation. The record shows precisely the contrary.

Southern Parties' discussion of extra-record sources about power shortages in the San Francisco Bay Area this summer (Southern Brief at 70-71) is procedurally improper, but it is unconvincing in any event. There is no allegation, nor any basis for an allegation, that the transmission constraints experienced in the Bay Area during the summer of 2000 were in any sense cause by, or related to, performance of existing RMR units, such as those operated by Southern Parties. As the record in this case plainly confirms, over-compensating existing RMR owners, as Southern Parties proposed here, can only distort incentives for investment in new generation and transmission resources needed to meet future demand.

G. Signatories' Response to Southern Parties' Allegation That The Net Incremental Cost Methodology Endorsed By The Initial Decision "Relies on Highly Speculative Estimates of Revenues and Opportunity Costs."

Southern Parties' final challenge to the net incremental cost rate methodology is their allegation that it "calls for extreme degrees of speculation that go far beyond what can prudently be relied upon in establishing rates for service that is critical to ensuring reliability." (Southern Brief at 72.) The record in this case shows otherwise.

As the I.D. noted, for all their claims about the difficulty of identifying and quantifying opportunity costs, "Southern Parties were unable to identify any opportunity costs which Mr. Weingart failed to consider, apart from unsupported/unquantified claims that net incremental cost compensation: (1) deprives them of 'location rents' (vs. local market power); and (2) that forbearance from electing RMR Agreement Condition 2 status represents an opportunity cost." (I.D., *mimeo* at 28, n.29.) There is no basis for second-guessing the Administrative Law Judge's factual finding that the net incremental cost rate methodology "reasonably accounts for, and full compensates, all costs related to Southern Parties' RMR obligations." (I.D., *mimeo* at 28.)

H. Signatories' Response to Southern Parties' Allegation That The Extremely High Fixed Option Payments They Proposed (Cumulatively, 77 Percent Of Their Settled Fixed Cost) Would "Produce a Just and Reasonable Result."

Only in the very last part of their Brief on Exceptions do Southern Parties devote any attention to their own proposal to allocate 77 percent of their settled fixed costs of their power plants (AFRR) to the ISO under the RMR Agreements. (Southern Brief at 77-86.) This highly unreasonable allocation of costs to the ISO, and hence to captive ratepayers, was soundly and convincingly rejected by the Administrative Law Judge in this case. (*See* I.D., *mimeo* at 23-25.) Southern Parties' half-hearted defense of their allocation scheme in the Brief on Exceptions provides no basis for overruling the Administrative Law Judge's sound ruling on this proposal, based on his key finding that the record evidence in this case simply did not support Southern Parties' strained analogy between the RMR Agreements and traditional "capacity" contracts.

V. CONCLUSION

The Commission should affirm the Administrative Law Judge's well-reasoned Initial Decision in this proceeding.

Respectfully submitted,

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Dated: July 27, 2000

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served on those parties on the restricted service list compiled by the Presiding Administrative Law Judge in these proceedings.

Dated at Washington, D.C., this 27th day of July, 2000.

____

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