UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern Energy Delta, L.L.C.	**)**	**Docket No. ER00-2726-000**
Southern Energy Potrero, L.L.C.	**)**	**Docket No. ER00-2727-000**

MOTION TO INTERVENE AND PROTEST OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Pursuant to Rules 211 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §§ 385.211, 385.214, the California Independent System Operator Corporation ("ISO") hereby protests and moves to intervene in the above-captioned proceedings. In support thereof, the ISO states as follows:

I. COMMUNICATIONS

Please address communications concerning this filing to the following persons:

Charles F. Robinson, General Counsel
Roger E. Smith, Senior
Regulatory Counsel
Beth Ann Burns, Regulatory Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 608-7135
Fax: (916) 608-7222

Edward Berlin
J. Phillip Jordan
Michael E. Ward
Swidler Berlin Shereff Friedman, LLP
3000 K Street, NW, Suite 300
Washington, DC 20007
Tel: (202) 424-7500
Fax: (202) 424-7643

II. BACKGROUND

Southern Energy Delta, L.L.C. and Southern Energy Potrero, L.L.C. (together, "Southern Companies") propose in this filing amendments to their Must-Run Service Agreements ("MRSAs") with the ISO. The amendments would provide the Southern

Companies with an additional payment under the MRSAs in the nature of a formula rate. Southern Companies assert that this new payment is justified by increased costs associated with Amendment No. 26 to the ISO Tariff.

Under Section 5.2 of the ISO Tariff, the ISO designates certain Generating Units as Reliability Must-Run ("RMR") Units because operation of those units is required under some conditions to provide local grid reliability. The ISO is entitled to call upon those RMR Units for Energy and Ancillary Services to ensure the reliability of the ISO Controlled Grid. The MRSAs are the contracts under which the Southern Companies provide RMR services to the ISO. The MRSAs provide for payment of variable costs associated with the provision of RMR services and a Fixed Option Payment ("FOP") to compensate the Southern Companies for the availability of their RMR Units.

The terms and conditions of the RMR Contracts were the subject of a partial settlement filed with the Commission on April 2, 1999, and accepted by the Commission on May 28, 1999. *Pacific Gas & Electric Company*, *et al.*, 87 FERC ¶ 61,250 (1999). The partial settlement resolved all but a few of the issues concerning the RMR Contracts, and included amendments to both the ISO Tariff and the *pro forma* MRSA. Among the unresolved issues was the level of the FOP in the Southern Companies' MRSAs. This issue is being litigated in Docket No. ER98-495-000. In that proceeding, the ISO has taken the position that RMR Contracts are unlike traditional power supply contracts for firm capacity because they explicitly grant RMR Owners the ability to retain the financial benefits that accrue when RMR Units are economic to operate (i.e., when market Energy prices exceed the units variable operating costs). Rather than providing firm capacity service, RMR Contracts provide California consumers (through the ISO and the Participating Transmission Owners) the ability to ensure that RMR Units operate when needed for local reliability. RMR Contracts also mitigate the market power that these units could exercise because they are uniquely located to serve specific reliability needs; this mitigation enables the units to earn market-based rates. For these reasons, the ISO (along with the Commission Staff, the California Public Utilities Commission, the California Electricity Oversight Board, and the Participating Transmission Owners) believe that the FOP should represent the RMR Owner's net incremental costs, i.e., incremental costs attributable to providing RMR service (which include any amount by which going forward costs exceed market revenues), net of any incremental revenues attributable to RMR service. In an Initial Decision issued on June 6, 2000, the Presiding Judge in that proceeding adopted the net incremental cost approach. *Pacific Gas and Electric Company*, Initial Decision, 90 FERC ¶ 63,008 (2000).

Among the issues that were addressed in the partial settlement was the timing of Dispatch Notices for Ancillary Services or Energy under the RMR Contracts. Section 4.2 of the MRSA provides that the ISO shall issue Dispatch Notices for Energy no earlier than the establishment of Final Day-Ahead Schedules for the Day-Ahead Market, unless the ISO Tariff is amended to permit otherwise. The Stipulation and Agreement provide that a filing to alter the timing of the Dispatch Notice must include an express recognition that the proposed change alters the basis on which certain RMR Owners accepted FOP levels; that such owners may file under Section 205 for revised payment levels (solely to reflect the effect of that filing); and that such filings under Section 205 should, to the extent practicable, be consolidated or resolved concurrently with the proposed tariff change.

On January 28, 2000, the ISO filed Amendment No. 26 of the ISO Tariff, which amended the ISO Tariff to provide that the ISO shall issue Dispatch Notices for Energy, to the extent the need for such Energy is known, two hours before the close of the PX Day-Ahead Market. Amendment No. 26 was approved by the Commission on March 31, 2000, *California Independent System Operator Corp.*, 90 FERC ¶ 61,345, *reh'g pending* (2000). Amendment No. 26 provides RMR Owners the option of accepting payment under the MRSA or payment through the markets. In either instance, the Energy required from the RMR Unit to ensure reliability must be bid into the PX forward markets or scheduled in bilateral transactions and, to the extent possible, scheduled against Demand in the Preferred Schedules submitted to the ISO.

Southern Companies assert that the instant filing implements their right to request an increase in their FOP following a modification of the timing of RMR Dispatch Notices. They contend that the timing and payment provisions of Amendment No. 26 cause them to incur additional "Collateral Costs" in providing RMR service, which include, but are not limited to

> (i) billed costs from the PX or ISO for any amount of the MWh or MW/h contained in a Dispatch notice when a unit is forced out of service either fully or partially, or expenses reasonably incurred to hedge against such billed costs, (ii) costs related to any inability of an Owner's [sic] to elect payment paths for supplemental dispatch calls, and (iii) all other opportunity costs, foregone revenues, or other costs the compensation for which is necessary to hold an Owner harmless from the effects of Amendment No. 26.

Southern Companies propose to recover these costs through a formula rate.

III. BASIS FOR MOTION TO INTERVENE

The ISO is a non-profit public benefit corporation organized under the laws of the State of California. It is responsible for the reliable operation of a grid comprising the transmission systems of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, as well as for the coordination of the competitive electricity market in California. The ISO is the sole purchaser of the services provided under the MRSAs. The ISO therefore has an interest in this proceeding. Further, because the ISO is charged with the nondiscriminatory operation of the ISO Controlled Grid, the ISO's participation in this proceeding is in the public interest. Accordingly, the ISO requests that it be permitted to intervene in this proceeding with full rights of a party.

IV. PROTEST

A. SOUTHERN COMPANIES' PROPOSED FORMULA RATE IS CONTRARY TO COMMISSION POLICY AND TO THE STIPULATION AND AGREEMENT

1. SOUTHERN'S PROPOSAL LACKS THE SPECIFICITY REQUIRED FOR FORMULA RATES.

The Commission has long accepted formula rates, which calculate the rate based on identified cost components, in lieu of fixed rates. Over the years, however, the Commission has developed a policy under which formula rates must be stated with specificity. *See, e.g., Maine Yankee Atomic Power Company*, 42 FERC ¶ 61,307 at 61,293 (1988); *Bangor Hydro-Electric Company*, 86 FERC ¶ 61,281 (1999). Recently, for example, the Commission required the ISO to file under Section 205 of the Federal Power Act whenever it proposed to allocate the costs of RMR Units outside of the ISO

Controlled Grid to more than one utility in proportion to the benefits received. The Commission concluded that the charges to the utilities were formula rates, and that the ISO's proposal did not specifically identify how the allocation would be calculated. *California Independent System Operator Corporation*, 89 FERC ¶ 61,229. Southern Companies' proposed formula rate does not even approach the Commission requirements for specificity. It does not define the "Collateral Costs" that are to be used in the formula or limit them in any way (other than to state that they must be verifiable and quantifiable); it only provides examples of what "Collateral Costs" might be. The proposal would grant Southern Companies *carte blanche* to include anything they consider to be a "Collateral Cost."

Further, one of the examples the Southern Companies do provide is "other opportunity costs," which they neither define nor limit. The Commission has been particularly concerned with the potential for abuse inherent in "opportunity cost" charges. In Order No. 888,[1] in the context of transmission charges, the Commission set forth specific requirements for rates based on opportunity costs: (1) a fully-developed formula *describing the derivation of opportunity costs*; (2) supporting data that demonstrates that the opportunity cost proposal is consistent with comparability; and (3) procedures that make available to customers the information needed to calculate and verify opportunity costs. FERC Stats. & Regs. ¶ 31,036 at 31,740. Citing Order No. 888, the Commission, in *Allegheny Power System, Inc.*, 80 FERC ¶ 61,143 at 61,550 (1997), rejected a formula rate that included opportunity costs as insufficiently specific.

[1] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed.Reg. 21540 (May 10, 1996), FERC Stats. & Regs., ¶ 31,036, April 24, 1996, Docket Nos. RM95-8-000 and RM94-7-001

The Commission cited, as an example, the formula component for redispatch costs, which stated that such costs would be computed using load flow analysis to determine whether a particular transaction had caused the utility to redispatch generating resources and the component would be the difference between out-of-pocket costs the utility would have incurred under economic dispatch and the out-of-pocket costs incurred after implementing redispatch. Southern Companies' proposal is far less specific. For example, Southern Companies do not specify criteria for determining when the inability to change their payment option in response to a supplemental RMR Dispatch Notice would cause them to incur opportunity costs. The total lack of specificity in Southern Companies' formula rate compels rejection of the proposal.

2. SOUTHERN'S PROPOSAL IS IMPERMISSIBLE UNDER THE STIPULATION AND AGREEMENT.

Under Article I, Section C.2 of the Stipulation and Agreement, Southern Companies are prohibited, with certain exceptions, from filing amendments to the MRSAs prior to January 1, 2002. Southern Companies contend that the instant filing is a permissible exception under Article II, Section B.3(c), which provides:

> In the event the ISO seeks to modify the ISO Tariff to provide for dispatch of RMR Energy at any time prior to the ISO's establishment of Final Schedules for the Day-Ahead Market . . . , then an RMR Owner shall be permitted to file to increase the level of the Fixed Option Payment, solely to reflect the effect of the ISO filing . . . .

The FOP is defined in Article II, Section B.3(a) as "a payment representing all or a specified portion of the fixed costs of an RMR Unit." Thus, the Stipulation and Agreement allows the Southern Companies to file to increase the portion of their fixed costs that are represented by the FOP.

Thus, the Southern Companies could, within the constraints of the Stipulation and Agreement, propose to increase their interim "Fixed Option Payment Factor" from 0.5 (as specified in the interim MRSA Schedule B) to 0.6 (or, following Commission action in Docket No. ER98-495-000, to increase FOP established therein) in order to address costs, including opportunity costs, that result from Amendment No. 26. Indeed, in Docket No. ER98-495-000, the ISO and others advocated consideration of opportunity costs as part of the Southern Companies net incremental costs. In order to justify the increased FOP, however, the Southern Companies would have to prove significant opportunity or other collateral costs, quantify them and provide cost support, and establish that they derive from Amendment No. 26 and are imposed only on RMR Units as opposed to all merchant Generators. As discussed below, the Southern Companies have done none of these, and indeed have submitted no cost support whatsoever.

In contrast to the permissible amendment, the formula rate proposed by the Southern Companies is not an increase in the level of the FOP. Although the Southern Companies purport to modify the Fixed Option Payment Factor, in reality they propose to charge the ISO a specified portion of their fixed costs (i.e., the FOP) *plus* an adder (unrelated to fixed costs) that is not expressed as a portion of their fixed costs. [2]

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[2] When the Southern Companies proposed Fixed Option Payment Factor is applied to the other elements of the Hourly Availability Charge, it becomes apparent, as shown below, that he "Collateral Costs" factor is a separate hourly charge, independent of the Annual Fixed Revenue Requirement.
*Hourly Availability Charge = (Hourly Availability Rate * Fixed Option Payment Factor).*
Hourly Availability Rate = Annual Fixed Revenue Requirement (AFRR)/Target Available Hours.
Fixed Option Payment Factor = 0.5 + (Collateral Costs/AFRR).
Thus*, **Hourly Availability Charge** = 0.5*(AFRR/Target Available Hours) + (Collateral Costs/AFRR)*(AFRR/Target Available Hours) =*
0.5*(Hourly Availability Rate) + (Collateral Costs/Target Available Hours).

Under no reasonable interpretation of the Stipulation and Agreement can this adder be considered as part of the FOP. As a result, it is an impermissible amendment to the MRSAs and should be rejected.

B. SOUTHERN COMPANIES HAVE NOT JUSTIFIED THE PROPOSED CHARGES FOR "COLLATERAL COSTS"

The basis for Southern Companies' proposed amendments to the MRSAs is their asserted right to compensation for "Collateral Costs" that they contend ensue from Amendment No. 26. As an initial matter, the ISO notes that the Stipulation and Agreement does not *entitle* Southern Companies to the recovery of additional costs occasioned by a change in the timing of Dispatch Notices. Rather, it merely allows the Southern Companies to file to recover such costs. Other parties are free to oppose recovery.

Even if the Southern Companies were able to demonstrate the existence of "Collateral Costs," that alone would not establish that those costs should be recovered. The ISO should not be required, when making market design modifications in the interest of operational efficiency (such as Amendment No. 26), to design payment schemes to off-set any potential impacts of these changes on all Market Participants. Market Participants decide to participate in newly deregulated markets with the knowledge that many modifications in market design may be made based on operating experience and on-going efforts to increase market efficiency through key design changes. Only to the extent that Southern Companies can show that Amendment No.

26 caused a *significant* increase in the net incremental costs[3] *attributable to their status as RMR Owners* should an increase in the FOP be considered.

Although Southern Companies do not limit the "Collateral Costs" they intend to include in their formula rate, they do list seven examples of such costs:

> (1) Increased risk in the Day-Ahead Market;
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> (2) The "locked-in" nature of the market/contract path election as regards supplemental RMR calls;
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> (3) Preemption from full participation in downstream markets;
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> (4) Suppression of the Day-Ahead Energy market clearing price;
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> (5) Increased price risks from the interaction of predispatch with the ISO's new target price methodology;
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> (6) Increased price risks from the potentially greater use of RMR Units; and
>
> (7) The substantially increased "costs of cover" for RMR Energy that cannot be supplied in response to an RMR call due to a forced outage.

Affidavit of Alan L. Madian at 3-4. The ISO agrees that the second and seventh of these may be legitimate concerns. In response to these (and other) concerns, the ISO has initiated a stakeholder process that will include these issues. See Attachment 1. The stakeholder process will assist the ISO to determine whether such concerns may be addressed without undermining or compromising the fundamental objective of

[3] The FOP calculation adopted by the Presiding Judge in Docket No. ER98-495-000 includes a significant "margin" or "deadband" which would prevent the estimated FOP (which the Presiding Judge based on the net incremental cost methodology) from increasing unless the additional opportunity costs were quite significant. In determining net increment costs associated with RMR Contracts, PG&E witness Weingart, whose calculations the Presiding Judge adopted, first calculated "operationally-related incremental costs and reasonably identifiable opportunity costs", and then subtracted "reasonably identifiable opportunity benefits". In cases where these RMR-related benefits exceeded costs, this difference was not subtracted from the administrative costs of RMR Contracts. *Pacific Gas and Electric Company* Initial Decision, 90 FERC ¶ 63,008, slip op. at 28-29 (2000). As calculated from Exh. PGE-9 in Docket No. ER98-495-000, over $1.67 million in "reasonably identifiable opportunity benefits" were excluded from the final amount of the fixed payment because total opportunity benefits exceeded opportunity costs. Thus, absent increased identifiable opportunity costs of more than $1.6 million, applying the net incremental costs methodology adopted by the Presiding Judge would not yield a higher FOP.

Amendment No. 26 or the net incremental cost principle upon which the FOP should be based. The ISO is committed to exploring through this stakeholder process options for addressing these two concerns that avoid creating any potentially perverse financial incentives, gaming opportunities or operational risks. The ISO does not, however, believe that it is proper to resolve these issues through an increase in the FOP of a particular RMR Unit. With regard to Dr. Madian's seventh item – determining the appropriate increase in the FOP to address the "costs of cover" would require a mechanism to estimate the frequency of forced outages and the Energy prices.[4] This could cause significant under- or over-payment to the Southern Companies. Similarly, with regard to Dr. Madian's second item – it would be far simpler to revise the tariff to allow an RMR Owner to select a different payment option in a Supplemental Dispatch Notice than to attempt to devise a means for quantifying any lost opportunity costs that may arise from existing ISO Tariff provisions. Thus, the appropriate mechanism for addressing "costs of cover"[5] or the inability of an RMR Owner to select a different payment option for a Supplemental Dispatch Notice – if it is determined that the concerns warrant remedial action – is through an amendment to the ISO Tariff.

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[4] For example, any resolution of the "cost to cover" issue would need to include measures to ensure that the outages are indeed forced and must to take into account the ability of RMR Owner to mitigate those costs through Unit Substitution under the RMR Contacts.

[5] It should be noted, however, that the scenario provided by Southern Companies is flawed. The example is inaccurate in that it does not account for the fact that Southern would incur a 682 MW imbalance that would be met at the Real Time price, but it would also be credited for the full 682 MW at the PX Day-Ahead price. Thus, any net cost to Southern as a result of the outage would be equal to the amount (if any) by which the real time imbalance charges exceeded revenues from the PX market over this 24-hour period.

In addition, the specific numbers in Dr. Madian's "base case" example grossly overstate the actual expected value of such an incident. Based on actual observed prices in the Day-Ahead PX and Real Time Imbalance Energy Market in the ISO's first two years of operation, the average or *expected value* of the scenario presented would in fact be a loss of only $11,739, versus the $1.2 million in the "base case" presented by Dr. Madian.

The other five concerns raised by Southern Companies are either insubstantial or do not represent a net incremental cost of RMR designation. As such, they do not justify an increase in the FOP.

1. Increased Risk in Day-Ahead Market

Southern Companies assert that requiring RMR Owners to choose the Market or Contract Path prior to the Day-Ahead Market increases the risks to which the companies are exposed. The Commission, however, has already addressed this argument in its order approving Amendment No. 26. In response to the expression of this concern by Southern Companies and others, the Commission directed the ISO to revise Amendment No. 26 to permit owners to select a separate payment option for each hour, rather than the entire day. The Commission concluded that this revision adequately addressed concerns regarding additional risk:

> RMR owners now have almost two years of experience dealing with bidding behavior, market clearing prices, and the time periods when their variable costs are greater than the market clearing price. Based on its experience, the RMR owner can select the contract path for the hours it believes its variable costs will exceed the market clearing price and be assured full recovery of its costs, and the RMR owner can select the market path to maximize its revenue stream when it believes that the market clearing price will exceed its variable costs. In any event, RMR owners may always choose the "contract path" and avoid *all* risks of underrecovering their variable costs. We believe that permitting RMR owners the option of choosing which hours they wish to receive[ ] a contract or market payment adequately responds to intervenor concerns that in some instances an RMR unit may receive less than its variable cost during some hours.

90 FERC at 62,140.

Indeed, the option of selecting payment under the MRSA when market Energy prices fall below a unit's variable operating cost actually offers significant *benefits* to Southern Companies that are not available to other merchant Generators. Because of minimum unit operating constraints, start-up costs and start-up lead times, and the hourly nature of California's Energy and Ancillary Services Markets, it may often be more economic for a Generator to operate as a "price taker" in the forward Energy markets, rather than shut down, during certain hours when the PX Market Clearing Price is less than the unit's variable operating costs. RMR Contracts often enable Generators to avoid "off-peak losses" during such hours by allowing them to select the contract path and recover full variable operating cost payments when they receive an RMR Dispatch Notice, rather than operate as a "price taker" at their minimum operating level in the Energy market. Indeed, RMR Contracts specify the RMR Unit's minimum operating levels and run-times, which may require the ISO to issue Dispatch Notices for such minimum generating levels during off-peak hours in recognition of these unit constraints, even if Generation to meet local reliability criteria is only actually necessary from these units during peak hours. Amendment No. 26 *increases* the ability of RMR Owners to maximize these benefits by giving RMR Owners perfect knowledge of RMR requirements *before* they must decide whether to schedule these units through the market or contract path, thus decreasing the risks associated with participation in the Day-Ahead Market. Moreover, the revision of Amendment No. 26 to allow owners to select a payment option on an hourly basis enhanced the ability of RMR Owners to avoid the risk of "Off-Peak Losses." These reduced risks counterbalance any increased risk that may arise from the requirement that the RMR Energy be scheduled in the forward markets.

3. Preemption of Market Opportunities in Downstream Markets

Southern Companies contend that Amendment No. 26 imposes “Collateral Costs” because of lost opportunities in “downstream markets.” Any such costs, however, would be de minimis.

First, it is important to note that Amendment No. 26 does not preclude the Southern Companies from participating in the Day-Ahead or Day-of Energy markets, through either the PX or a bilateral transaction. Even with regard to other markets (such as the Ancillary Services and Real Time Imbalance Energy markets), Amendment No. 26 only precludes the Southern Companies from bidding a specified portion of their total capacity – the portion that the ISO requires to ensure system reliability – into those markets. Thus, the real issue is whether such limitations are likely to create *significant unavoidable opportunity costs* for Southern Companies, which place them at a disadvantage relative to other merchant Generators.

In practice, the majority of the capacity owned by merchant Generators in the ISO system is scheduled in forward Energy markets or bilateral transactions appearing in Final Hour-Ahead Schedules. The Ancillary Services and Real Time Energy markets represent a relatively small and often volatile portion of the overall wholesale Energy market. During the ISO’s second year of operation from April 1999 through March 2000, the total cost of Ancillary Services capacity payments represented about 6.5% of the total Energy costs in the Day-Ahead and Day-of markets.[6] Meanwhile, the amount of incremental energy dispatched by the ISO in the Real Time Energy Market during its second year of operation averaged only about 490 MW, or less than 2% of total average system loads of 26,288 MW, with total revenues paid for incremental energy dispatched by the ISO equaling only about 4.2% of the total value of energy scheduled in the Day-of market.[7]

Over the long run, competitive forces and the ability of suppliers to arbitrage between markets with significant amounts of capacity can be expected to keep profit margins in these other "downstream markets" (such as Ancillary Services and Real Time Imbalance Energy) comparable to those in the forward Energy markets. Because of the relatively small volumes of these other markets (which typically do not exceed several thousand MW) compared to total forward Energy markets, individual large suppliers (in the absence of market power) are typically limited in their ability to simply forego the forward Energy markets and commit capacity to the Ancillary Services and Real Time Energy markets without decreasing prices in these markets to the point where their net profit margins in these markets would be comparable to or even lower than that in the forward Energy markets.

4. Suppression of Market Clearing Prices

Southern Companies also attempt to justify an increase in the FOP on the basis that Amendment No. 26 reduces the Market Clearing Prices in the forward markets. The Southern Companies, however, offer no evidence that Amendment No. 26 has affected Market Clearing Prices and there is no basis for even assuming such an impact exists. Indeed, although the ISO did support Amendment No. 26 in part on the grounds

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[6] Total costs of Ancillary Services procured by the ISO ($360 million), as a percentage of total costs of Energy in Day-of market ($5.6 billion) calculated by multiplying Final Hour-Ahead Schedule by Day-Ahead PX unconstrained price.

[7] Total costs of incremental energy dispatched by the ISO ($240 million), calculated by multiplying incremental energy dispatched each hour by the average of the real time price in the NP15 and SP15

that previous RMR dispatch protocols may artificially inflate Market Clearing Prices in the forward Energy markets, the Commission itself has concluded that Amendment No. 26 will not necessarily reduce Energy prices in the forward market:

> While we are persuaded that failure to pre-dispatch has created operational difficulties, we are not persuaded that it has produced any systematic price increases [in the Day Ahead PX market]. The evidence presented by the ISO suggests that the current dispatching mechanism has not inflated forward market prices, and that pre-dispatch will not lower them.

90 FERC at 62,139. Further, as noted in the ISO's response to protests on Amendment No. 26, any attempt to isolate and quantify the impacts of pre-dispatch on market prices, even on an ex post basis, is subject to a wide range of uncertainty. Even if one assumes, *arguendo*, that ex post analysis did indicate that pre-dispatch had a quantifiable effect on forward market prices, it would be inappropriate to attempt to directly base compensation paid to any Market Participant on such analyses. Such analyses are typically conducted to provide decision-makers with an indication of the approximate magnitude and range of the impact of changes in market design. Allowing any compensation to Southern Companies based on such analyses would create another lengthy, costly, and contentious process and source of potential litigation before the Commission.

In addition, even if Amendment No. 26 did have a quantifiable effect on forward market prices, it would not represent a net incremental cost of being designated RMR. The removal of any price distorting effect created by the timing of RMR Dispatch Notices under previous procedures would affect *all* Market Participants equally, not just RMR Owners. The underlying principle of the net incremental cost methodology is that

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zones, as a percentage of total costs of Energy in Day-of market ($5.6 billion) calculated by multiplying final Hour Ahead Schedule by Day-Ahead PX unconstrained price.

RMR Contracts should be designed to make RMR Generators no better and no worse off than other merchant Generators merely because of their RMR status. Compensating RMR Owners for any estimated impact of Amendment No. 26 on forward market prices, as the Southern Companies propose, would make RMR Owners significantly better off than they would be absent their RMR status, and better off than Generators without RMR status.

5. Risks from the Target Price Proposal

The Southern Companies' fifth asserted category of "Collateral Costs" is the "exacerbat[ion]" of the impact of Amendment No. 26 that they allege will result from the ISO's recent changes in the mechanism for determining the "target price" by which the ISO harmonizes incremental and decremental Imbalance Energy Bids. The changes to the ISO's target price methodology, however, represent a market design change that is unrelated to changes made by Amendment No. 26. The Stipulation and Agreement authorizes the Southern Companies to file to increase the FOP "solely to reflect the effect of the ISO filing [to change the timing of RMR Dispatch Notices]."[8] Thus, any increased costs occasioned by the change in target price methodology are not within the scope of a permissible filing.

Moreover, the major impact of the new target price methodology is an increased incidence of zero-priced hours in the Real Time Market. This has the effect of *decreasing* rather than increasing any "Collateral Cost" associated with the requirement that RMR Energy under contract path be scheduled in the forward market. Thus, any

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[8] Absent such a limitation, every change in market design could prompt a comparison of the pre- and post-Amendment No. 26 impacts and produce yet another proposed revision of the FOP. The limitations on amendments to the MRSAs during the rate freeze would become virtually meaningless.

increased incidence of zero prices in the Real Time Market would lead RMR Owners to schedule Energy in the forward markets *more often* than they would otherwise. The effect of increasing the number of zero priced hours in the Real Time Market would be to *reduce* rather than *increase* any opportunity costs associated with any limitations RMR Contract requirements may place on the Southern Companies' ability to supply generation in the Real Time Market.

6. Risks from Potential Use of RMR Calls to Minimize Costs

Southern Companies also allege that, armed with the expectation that Amendment No. 26 will reduce forward market Energy prices (a premise that, as noted above, the Commission has already rejected), the ISO will dispatch RMR Units to levels above what it requires to maintain system reliability in order to drive down market prices and, ultimately, costs to consumers. Section 4.1 of the MRSA prohibits the ISO from dispatching RMR Units to accomplish such a goal:

> 4.1 (b) Dispatch Notices for Energy, other than Energy associated with Ancillary Services, shall be issued solely for purposes of meeting local reliability needs or managing intra-zonal congestion.

The ISO is obligated to abide by the terms of its tariff and does not treat that obligation lightly. If the Southern Companies conclude that the ISO has increased dispatch of RMR Units to serve the end that the Southern Companies posit, rather than to uphold its statutory obligation to maintain system reliability in light of load growth, unforeseen unit outages, or other factors, then Southern Companies' remedy lies in a complaint with the Commission. Such speculation that the ISO will ignore its responsibilities, even if it were not baseless – which it is – does not establish an increased market risk for which Southern Companies deserve compensation through the FOP.

C. EFFECTIVE DATE

Southern Companies request a waiver of the Commission's regulations such that the amendment to the MRSAs may become effective on June 1, 2000. The Southern Companies have provided no justification for such a waiver. The amendment to the MRSAs could have been filed at any time after January 28, 2000, when the ISO filed Amendment No. 26. Indeed, the provisions of the Stipulation and Agreement that address the consolidation of an ISO filing to change the time of Dispatch Notices with RMR Owners' filings to increase the FOP contemplate that the issues be considered simultaneously – not more than five months after the ISO filings and two months after the Commission's order on the ISO's filings. The Southern Companies' delay is of their own making. If, despite the deficiencies outlined above, the Commission accepts the amendment, it should deny the waiver.

V. CONCLUSION

Wherefore, for the foregoing reasons, the ISO respectfully requests that the Commission permit it to intervene, that it be accorded full party status in this proceeding, and that the Commission reject the revisions to the Must-Run Service Agreements proposed by the Southern Companies.

Respectfully submitted,

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Charles F. Robinson, General Counsel
Roger E. Smith, Senior
Regulatory Counsel
Beth Ann Burns, Regulatory Counsel
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 608-7135
Fax: (916) 608-7222

Edward Berlin
J. Phillip Jordan
Michael E. Ward
Swidler Berlin Shereff Friedman, LLP
3000 K Street, NW, Suite 300
Washington, DC 20007
Tel: (202) 424-7500
Fax: (202) 424-7643

Counsel for the California Independent
System Operator Corporation

Date: June 21, 2000

June 21, 2000

VIA MESSENGER

David P. Boergers, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: **Southern Energy Delta, L.L.C., Docket No. ER00-2726-000 and Southern Energy Potrero, L.L.C., Docket No. ER00-2727-000**

Dear Secretary Boergers:

Enclosed for filing are one original and fourteen copies of the Motion to Intervene and Protest of the California Independent System Operator Corporation in the above-cited proceedings. Two additional copies of the filing are also enclosed. I would appreciate your stamping the additional copies with the date filed and returning it to the messenger.

Respectfully submitted,

J. Phillip Jordan
Counsel for the California Independent System
Operator Corporation

CERTIFICATE OF SERVICE

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

Dated at Washington, DC, on this 21st day of June, 2000.

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J. Phillip Jordan