UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)	**Docket No. ER04-835-000**
	)	
Pacific Gas and Electric Company	)	
v.	)	
California Independent System Operator Corporation	)	**Docket No. EL04-103-000 (consolidated)**

INITIAL BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Charles F. Robinson
General Counsel
Anthony J. Ivancovich
Assistant General Counsel
Stephen A. S. Morrison
Corporate Counsel
The California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630
Tel: (916) 608-7049
Fax: (916) 608-7296

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

Dated: August 16, 2005

TABLE OF CONTENTS

TABLE OF AUTHORITIES

COURT CASES

COMMISSION DECISIONS

STATUTES AND REGULATIONS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)	**Docket No. ER04-835-000**
	)	
Pacific Gas and Electric Company	)	
v.	)	
California Independent System Operator Corporation	)	**Docket No. EL04-103-000 (consolidated)**

INITIAL BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

To: The Honorable H. Peter Young
Presiding Administrative Law Judge

INTRODUCTION

The California Independent System Operator Corporation ("ISO")[1] files this brief pursuant to the schedule established on the final day of the hearing in the above-captioned matter. This Initial Brief addresses the issues designated in the Joint Stipulation of Issues.

I. PROCEDURAL HISTORY

The participants in this proceeding prepared a Joint Procedural History, which was filed by the Southern Cities in advance of the hearing on June 14, 2005. Since the Joint Procedural History was filed, this proceeding underwent an eleven-day hearing. Also during this time, three stipulations were entered into by several, but not all, of the

---

[1] Capitalized terms not otherwise defined are used in the sense given in the Master Definitions Supplement, ISO Tariff Appendix A.

parties: Stipulation No. 1, regarding the evidentiary treatment of deposition transcripts, Stipulation No. 2, regarding the protected status of hearing exhibits, and Stipulation No. 3, regarding Docket No. EL04-103 Issue No. II from the Joint Stipulation of Issues. In addition, Proposed Joint Transcript Corrections were filed on July 29, 2005. An order adopting the transcript corrections and closing the evidentiary record was issued on August 1, 2005.

II. AMENDMENT NO. 60.

This proceeding centers on the ISO's proposal, in response to concerns expressed by stakeholders, to modify the allocation of Minimum Load Cost compensation ("MLCC") in a manner more consistent with cost causation. MLCC is paid to Generators as the compensation for their being required to operate their Generating Units at minimum load, in order that the Units will be available for dispatch by the ISO pursuant to the must-offer obligation established by the Commission during the 2000-01 California Energy Crisis.[2] As described in Exh. ISO-20, the ISO undertook a re-examination of its implementation of the must-offer requirement in response to Market Participants' concerns and solicited the views of Market Participants through a stakeholder process. Exh. ISO-20 at 14-15. As a result of this re-examination, it became apparent that a significant portion of the MLCC was being incurred to combat reliability problems of something less than a system-wide nature (*i.e.*, local or zonal reliability problems). The ISO, therefore, proposed to change the allocation of these

[2] As noted in the May 11 Amendment No. 60 filing, the Commission established the must-offer obligation in an April 26, 2001 order instituting certain price mitigation measures in California. *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services, et al.*, 95 FERC ¶ 61,115 at 61,354-56 (2001). *See also* Exh. ISO-22 at 8.

costs through Amendment No. 60. *Id*. at 13. As noted in the Joint Procedural History, the Commission set the aspect of Amendment No. 60 dealing with the proper allocation of MLCC for hearing in this proceeding.

As described in the testimony of ISO witness Jim McIntosh:

> The must-offer obligation requires all owners of non-hydro-electric Generating Units with Participating Generator Agreements to offer available capacity from those Generating Units to the ISO's real-time Imbalance Energy Market. To satisfy the must-offer obligation, Generating Units that cannot start up within the settlement time horizon of the real-time market (which currently settles on a ten-minute basis) must be operating at least at the Generating Unit's minimum operating level and bidding all available capacity above that minimum operating level into the ISO's real-time Imbalance Energy Market.

Exh. ISO-22 at 8-9. It is possible for the Scheduling Coordinator for a Generating Unit subject to the must-offer obligation to request a waiver of the must-offer obligation when it wants to shut that Generating Unit off, and the ISO determines whether to grant such waivers, based on the needs of the system or part of the system. If the ISO does not grant, *i.e.,* denies, a requested waiver, the Generating Unit must remain in operation and the ISO will pay the costs to operate the Generating Unit at its minimum operating level, including when the ISO dispatches Energy from the Generating Unit or the Generating Unit provides Ancillary Services. *Id.* The must-offer costs associated with a must-offer waiver denial ("MOWD") include Start-Up Costs and Emissions Costs as well as MLCC.

Prior to the filing of Amendment No. 60, all must-offer costs associated with waiver denials were allocated to metered Demand within the ISO Control Area, plus exports to other Control Areas within California. May 11 Transmittal Letter at 31. The Amendment No. 60 proposal divides the costs of compensating Generating Units for the

MLCC associated with "MOWDs" into three categories, each with its own allocation criteria: 1) those incurred for Local reliability, 2) those incurred for Zonal reliability, and 3) those incurred for System reliability. *Id*. Under Amendment No. 60, Local MLCC is charged to the Participating Transmission Owner ("TO") in whose service territory the Generating Unit is located; Zonal MLCC is charged to all metered Demand within the affected Zone; and System MLCC is charged to Net Negative Uninstructed Deviation up to a cap, after which the remainder is charged to metered Demand within the ISO Control Area, plus exports to other Control Areas within California.

III. ISO'S GENERAL POSITION

As discussed above, the ISO's purpose in this proceeding is to allocate the costs associated with the must-offer obligation in a manner that more directly reflects the distribution of the benefits provided. As with any cost allocation design, there will obviously be some "winners" and some "losers" under the ISO's proposed allocation as a whole, and under individual aspects of the allocation. The ISO, as a revenue-neutral entity, has no corporate stake in the allocation mechanism, apart from ensuring that any allocation methodology that is ultimately adopted does not result in excessive administrative and implementation demands on limited ISO resources. Thus, in evaluating the reasonableness of various, the ISO considers the costs involved in comparison to the benefits to be received by Market Participants. The ISO prefers to implement new initiatives within existing systems, whenever possible, as a means to reduce costs. Tr. 782-83 (Bodine). With these goals in mind, the ISO's positions reflect a concern that "perfect" allocation not become the enemy of "good" when it comes to an acceptable allocation mechanism.[3]

As noted by Staff witness Edward Gross, the must-offer obligation is temporary in nature. Exh. S-6 at 18, *citing* the Amendment No. 60 hearing order, 108 FERC ¶ 61,022 at P 62 (2004). Indeed, as described by ISO witnesses at the hearing, Must-Offer will disappear, or be altered beyond recognition, with the onset of the new market mechanisms of the ISO's market redesign or "MRTU."[4] *See, e.g*., Tr. 499:21-22; 725:19-20; 751:11-21; 776-77; 784:4-8. Current estimates put the implementation date for MRTU at February, 2007. *See, e.g., California Independent System Operator Corp.*, 112 FERC ¶ 61,013 (2005) at P 3; Tr. 499:14-15 (McIntosh). Thus, any improvements to be made in the allocation of must-offer costs will likely be effective for a period of no more than two and a half years. Evaluating the appropriate level of investment in personnel, software, and related market mechanisms in the revised allocation should be done in light of this period of effectiveness. Tr. 784:9-21 (Bodine).

As discussed below, with the exceptions noted, the ISO believes that Amendment No. 60 as proposed is within a zone that is reasonable and just and should be approved. In the event the Presiding Judge disagrees, the ISO's primary concern regarding competing just and reasonable proposals is that the proposals be implementable at a reasonable cost and without disrupting the ISO's progress towards a

---

3 Most parties would appear to agree that it is neither possible nor desirable to attempt to achieve "perfection" in the allocation of Amendment No. 60 costs. *See, e.g*., Tr. 992 (Goldbeck); Tr. 1062 (Marcus).

4 "MRTU" stands for the ISO's Market Redesign & Technology Upgrade, and was formerly known as "MD02".

long-term solution to the market flaws that gave rise to the need for mechanisms such as the must-offer obligation.

DISCUSSION OF ISSUES IN JOINT STIPULATION OF ISSUES

Docket No. ER04-835

I. Allocation of MLCC Costs

A. What factors should be considered in determining whether the ISO's Amendment No. 60 cost allocation proposal is just, reasonable and not unduly discriminatory?

1. The ISO Need Only Prove that Amendment No. 60 Is Just and Reasonable, Not that It Is the Most Just and Reasonable Proposal.

With one exception, discussed below, this proceeding presents no extraordinary circumstances and should be adjudged according to the standard Commission precedent for evaluating whether a tariff is just, reasonable, and not unduly discriminatory and also in accordance with prior Commission guidance regarding the must offer requirement. Many parties have put forth proposals for the allocation of MLCC, the subject matter of this proceeding. The ISO's proposal, however, is that contained in its May 11 Filing and it is that proposal, not alternatives proffered by others, that must, as a first step, be adjudged. The Presiding Judge must determine whether the ISO's proposal is just, reasonable, and not unduly discriminatory. 16 U.S.C. § 824d. For the rate design proposal to be acceptable, it need be neither perfect nor even the most "desirable"; it need only be reasonable. *See New England Power Co.*, 52 FERC ¶ 61,090 at 61,336 (1990), *reh'g denied*, 54 FERC ¶ 61,055 (1991), *aff'd Town of Norwood v. FERC*, 962 F.2d 20 (D.C. Cir. 1992); *citing City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir.), *cert. denied*, 469 U.S. 917 (1984) (utility need only establish that its proposed rate design is reasonable, not that it is superior to alternatives); *OXY USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) ("[T]he Commission may approve the methodology proposed in the settlement agreement if it is 'just and reasonable'; it need not be the only reasonable methodology or even the most accurate.").

Until and unless the Presiding Judge determines that the ISO's proposed allocation methodology is unjust, unreasonable, or unduly discriminatory, the existence of alternative proposals is not an appropriate factor to consider. The Commission's authority to prescribe a rate arises from section 206 of the Federal Power Act ("FPA"), and under section 206 the Commission can only exercise that authority following a finding that the rates proposed are unjust, unreasonable, or unduly discriminatory. 16 U.S.C. § 824e; *Sierra Pacific Power Co. v. FPC*, 350 U.S. 348 (1956).

In addition, it follows from these principles that the ISO's burden of coming forward with evidence that its proposal is just and reasonable is limited to those features of the allocation of MLCC that represent a change from the previous (*i.e*., pre-Amendment No. 60) methodology. If a party wishes to challenge a feature of the allocation methodology that is unchanged from the previous methodology that the Commission approved as just and reasonable, then that party bears the burden of furnishing evidence sufficient to establish that the feature in question is unjust or unreasonable. *See Public Service Comm'n of New York v. FERC*, 642 F.2d 1335, 1345 (D.C. Cir. 1980).

The exception mentioned above[5] involves Attachment E to the ISO's May 11 Filing, which includes the criteria that the ISO proposed to use to assign MLCC to each of the three proposed cost categories. The ISO did not propose to make this attachment part of the ISO Tariff, but in its Testimony the ISO has expressed a willingness to include it in the ISO Tariff. Much of the controversy in this proceeding involves the criteria in Attachment E. Because the ISO has made a proposal, but not as part of the tariff, and the inclusion of the Attachment E criteria as proposed or modified in the tariff could be part of a compliance order in this proceeding, it is unclear where the burdens lie regarding the criteria and language of Attachment E. One possible solution – which the ISO endorses below – is to deem Attachment E a part of Amendment No. 60 to the ISO Tariff.

2. The Presiding Judge Should Apply Established Principles of Cost Causation.

A fundamental requirement of a just and reasonable tariff is that it reflect the principle of cost causation. *Alabama Electric Cooperative, Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982). During the course of this proceeding, two issues have arisen with regard to cost causation principles. First, does allocation of the costs of services according to principles of cost causation include allocation to entities that receive benefits from the services performed? Second, how strong a correlation between (1) the allocation of charges and (2) the costs incurred or benefits received – *i.e.,* what degree of "granularity" – is necessary to establish that a tariff is just and reasonable?

[5] *See* page 6.

a. The Concept of Cost Causation Includes Proper Consideration of Benefits Received.

The argument that costs must be borne solely by the class of customers that “caused” them to be incurred in the first instance is simply not a limitation that the Commission accepts. For example, if an interconnection request requires transmission system upgrades that benefit all users of the grid, the Commission generally requires that the costs be assigned to all users of the Grid, not just to the entity requesting the interconnection. *See, e.g., Western Mass. Elec. Co.*, 66 FERC ¶ 61,167 (1994), *aff’d, Western Mass. Elec. Co. v. FERC*, 165 F.3d 922 (D.C. Cir. 1999). Citing *Western Massachusetts* for the proposition that “[e]ven if a customer can be said to have caused the addition of a grid facility, the addition represents a system expansion used by and benefiting all users due to the integrated nature of the grid,” the Commission has explicitly noted, “This treatment does not violate cost causation principles.” *Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States*, 96 FERC ¶ 61,155 at 61,674 n.39 (2001). *See also California Indep. Sys. Operator Corp*., 97 FERC ¶ 61,149 at 61,648 (2001).

In a proceeding involving many of the same parties as this proceeding, the Commission unequivocally affirmed the proposition that principles of cost causation require consideration of benefits received:

> [Cost causation] principles . . . have authoritatively been described thusly: "Properly designed rates should produce revenues from each class of customers, which match, as closely as practicable, the costs to serve each class of individual customer." While this fundamental idea of matching costs to customers is often referred to in terms of cost causation, it has also often been described in terms of the costs which "should be borne by those who benefit from them." Indeed, in a recent order rejecting arguments that ISO-related costs should not be assigned to PG&E's existing contract customers, the Commission expressly stated:

> Concerning the application of cost causation principles . . . enhanced reliability and market development resulting from industry restructuring are benefits that are distributed across the spectrum of energy participants.
>
> Thus, the Initial Decision accurately characterized cost causation and received benefits as alternate means of expressing the same concept.

California Indep. Sys. Operator Corp., 103 FERC ¶ 61,114 (2003) at P 26 (footnotes omitted). *See also Midwest Independent Transmission Sys. Operator, Inc., et al*., 108 FERC ¶ 61,163 (2004) at P 587 ("the Commission believes that the Midwest ISO has proposed a reasonable allocation of the day-ahead generator shortfall uplift costs because the parties expected to benefit from the commitment of these resources will be paying the costs of committing them"). The United States Court of Appeals for the District of Columbia has affirmed this approach, and reviews the Commission's compliance with cost causation principles "by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368-1369 (D.C. Cir. 2004), *citing KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300-01 (D.C. Cir. 1992).

The history of Minimum Load Cost compensation reflects an allocation based on those that receive the benefits of reliability. The Commission directed that the costs be recovered in the same manner as Start-Up and Emissions Costs. *See San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services, et al.*, 97 FERC ¶ 61,293 at 62,363 (2001). In the same order, the Commission concluded that assigning Emissions and Start-Up Costs to gross Load (in this case, all Load within the Control Area) was "appropriate in that all users of the transmission grid will be assigned these costs consistent with the ISO's markets performing a reliability function." *Id.* at 62,370.[6] What has changed with Amendment No. 60 is the need to assign MLCC at a more granular level in light of the recognition that certain benefits were being provided at a more granular level. In *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112 at PP 72-74 (2004) ("*PJM*"), the Commission recently reiterated the validity of a benefits approach even at an even more granular level. Although the California Department of Water Resources State Water Project ("SWP") appears to assert that in *PJM* "the Commission has emphasized the need to employ a cost causation – and not a benefits – approach," SWP Pre-Trial Brief at 6, that simply is not so. In *PJM* the Commission explicitly states that costs should be allocated based on benefits received. In that case, the Commission rejected PJM's proposed auction to secure long-term capacity, but set forth a number of factors for PJM to consider when drafting another proposal. One of these factors was to ensure that "the payment obligations resulting from the auction/RFP process should be allocated to the local area *benefiting* from the reliability improvement." *Id.* at P 22 (emphasis added).

b. There Are No Bright Lines, but the Allocation of Charges Must Reflect the Incurrence of Significant Costs or the Receipt of Significant Benefits.

Naturally, in considering whether an entity should share in costs, the decision-maker must analyze the degree of benefit an entity has received from the services in question. To allocate costs to a customer under the benefits-received approach, a utility must first determine that the customer received a sufficient benefit from the expenditure.

---

[6] In the passage cited, the Commission was responding to arguments that the charges should be confined to "net load," *i.e.,* Load that used the ISO Controlled Grid. The actual allocation approved included *all* users of the ISO Controlled Grid, gross Load in the Control Area and exports from the Control Area to Load in California.

The Commission has held that customers of a power grid substantially benefit from overall improvements to the reliability of a power grid, and may therefore bear the costs of such improvements. *Western Mass. Elec. Co.*, 66 FERC ¶ 61,167 (1994), *aff'd, Western Mass. Elec. Co. v. FERC,* 165 F.3d 922 (D.C. Cir. 1999). In fact, even if only one class of customer causes the need for reliability services, "these services nevertheless provide system-wide reliability benefits due to the integrated nature of the transmission grid" and the expense for the services "should be paid for by all users of the grid because of the grid-wide benefits." *Pacific Gas and Electric Co.*, 100 FERC ¶ 61,160 at P 15 (2002). The Commission's policy that: services that enhance overall grid reliability should be socialized across all users of the grid, is well established.[7]

On the other hand, "any" degree of benefit is not sufficient to justify the allocation of costs. If the benefit to the customer is very minor, then the customer should not be allocated a portion of the cost. In *American Electric Power Service Corp.,* 111 FERC ¶ 61,180 (2005), the claimed benefits – lower administrative costs, increased generation capacity, and more competition – were not substantial and the Commission would not support a broad allocation of costs to all members of the pool who "benefited" from the costs. *Id*. at PP 5, 25-30. *See also Louisiana Public Service Comm'n v. Entergy, et al.,* 96 FERC ¶ 63,002 at 65,010 (2001) (because the utility did not build or acquire capacity to serve interruptible loads, allocating capacity costs to interruptible loads violates the principles of cost causation allocation).

Recently, the Commission has often approved more granular cost allocation

[7] *See, e.g., Western Mass. Elec. Co.*, 66 FERC ¶ 61,167; *Removing Obstacles to Increased Electric Generation and Natural Gas Supply*, 96 FERC ¶ 61,155; *Midwest Independent Transmission Sys. Operator, Inc.*, *et a*l., 98 FERC ¶ 61,141 at 61,412 (2002).

methods, particularly with regard to uplift charges. For example, the Commission approved a cost recovery method that departed from the gross load method and instead allowed the Midwest ISO to charge must-offer reliability costs to participants based on net deviations from their day-ahead schedules. *Midwest Independent Transmission Sys. Operator,* 108 FERC ¶ 61,163 at P 587 (2004). In *PJM,* the Commission addressed reliability compensation costs for load pockets that could not be addressed through system redesign, but required infrastructure improvements. It expressed its preference that such cost allocations be performed at the local level when possible. *PJM* at 107 FERC P 74. Nonetheless, the Commission does not insist on such granularity. For example, a broad allocation of reliability costs may be appropriate when a narrow allocation would be overly burdensome to certain participants and discourage these participants from participating in the electricity market. *ISO New England, Inc.,* 111 FERC ¶ 61,442 at P 17 (2005).

What is apparent is that there are no 'bright lines'. The application of cost causation principles is not an exact science and more than one proposal may simultaneously be consistent with cost causation. The task here is simply to determine whether the ISO's proposal, under the facts presented, is a reasonable and nondiscriminatory allocation of charges according costs incurred and benefits received and – if not – which alternative proposal that is such an allocation should be adopted.

B. Whether it is just and reasonable to classify MLCC costs into three buckets: System, Local, and Zonal.

No participant in this proceeding has suggests that a different number of cost allocation "buckets" be used for the allocation of MLCC costs.[8] Several participants have, however, suggested that specific costs be allocated to buckets other than those to which the ISO proposes to allocate such costs, and some have argued that the ISO's proposed billing determinants for a given bucket are unjust and unreasonable.

There are likely a variety of classifications of MLCC costs that could be deemed just and reasonable. The ISO developed its categories, or three-bucket allocation proposal, through a lengthy stakeholder process to ensure it had taken into account the views of those who would be affected by the allocation of MLCC costs prior to filing Amendment No. 60. *See* Exh. ISO-20 at 14-19. They reflect a reasonable degree of granularity consistent with the current organization of the ISO markets. As discussed below, the three buckets also permit an allocation that rationally reflects the reasons that MLCC costs may be incurred and appropriately assigns those costs in a manner consistent with cost causation. Accordingly, the classification into three buckets is within the scope of what are just and reasonable rates.

---

[8] There has been some discussion of whether the proposal of SWP witness David Marcus regarding more precise geographic allocation of costs would constitute a "fourth bucket." *See, e.g.*, California Electricity Oversight Board Pre-Hearing Brief at 11. According to Mr. Marcus, however, his proposal would alter the allocation within the existing zonal bucket, rather than creating a fourth bucket. Tr. 1026-27.

C. Should MLCC costs be allocated, pursuant to the criteria used by the ISO to classify units committed under the Must Offer Wavier Denial (MOWD) process as set forth in Attachment E of the ISO's filing of May 11, 2004, to each of the Local, System, Zonal categories, or should they be allocated in another manner or to other categories?

1. The ISO's Proposed Criteria in Attachment E Appropriately Reflect Cost Causation.

For the purpose of this section, the ISO will assume that the Presiding Judge will conclude that Attachment E should be a part of the ISO Tariff and will determine (1) whether the proposed contents of Attachment E are just and reasonable and (2) if, not, whether they should be changed. As a general matter, the Attachment E criteria are just and reasonable because they reflect the categories and cost causation principles discussed above.

Under the Attachment E criteria, a unit is committed for Local purposes when it is committed or operated to:

1. maintain power flows on a transmission component that is not part of a transmission path between Congestion Zones;
2. maintain acceptable voltage levels at a network location that is not part of a transmission path between Congestion Zones; or
3. accommodate the forced or scheduled outage of a network component that is not part of a transmission path between Congestion Zones.

See Exh. S-18 at 9. These are all issues that arise from problems on the network under the control of the local Participating TO, to whom the Local MLCC will be charged. The ISO has subsequently proposed to exclude from this category specific constraints that affect the service territory of more than one Participating TO. Exh. ISO-22 at 23, 25-26.

Under the ISO's Amendment No. 60 proposal, Local MLCC costs are allocated to the Participating TO in whose Service Territory the Generating Units are located. This reflects precisely the degree of granularity of the definition of the Local bucket. It is thus consistent with the Commission's recommendations in *PJM*, that the costs be assigned to the affected Load and to the entity in the best position to reduce these costs by upgrading the power delivery network. 107 FERC ¶ 61,112 at P 74; *see also* Exh. ISO-22 at 30. (Although the costs are allocated to the Participating TO, the ISO assumes that the Participating TO is in a position to pass those costs to the appropriate Loads.)

Local MLCC costs are also similar to ISO RMR costs, which are incurred to address intra-zonal reliability issues. Exh. ISO-22 at 27. Under the ISO Tariff, those costs are similarly borne by the Participating TO in whose service territory the unit is located. *See* ISO Tariff Section 5.2.7 (Item by Reference 1, Sheet 173); Definition of "Responsible Utility", ISO Tariff Appendix A Master Definitions Supplement (Item by Reference 1, Sheet 345).

Under Attachment E, a unit is committed for Zonal purposes when it is committed or operating to:

1. maintain operations within the requirements of any nomogram that governs the operations of [an] Inter-Zonal transmission path(s);

2. maintain power flows on a transmission line that is part of a transmission path between Congestion Zones;

3. maintain acceptable voltage levels at a location that is part of a transmission path between Congestion Zones;

4. accommodate the forced or scheduled outage of a network component that is part of a transmission path between Congestion Zones; or

5. provide Ancillary Services within a particular Zone, if the ISO is procuring Ancillary Services on a Zone-by-Zone basis.

See Exh. S-18 at 10. The ISO has proposed that the Zonal category also include specifically identified Intra-Zonal constraints that affect the service territory of more than one Participating TO - in particular, the Miguel Substation transformer bank and the South of Lugo transmission path. Exh. ISO-22 at 23, 25-26. Although these constraints do not arise at an Inter-Zonal Interface, as required under the Attachment E criteria, they involve transmission paths that provide a regional, rather than a strictly local, benefit, *id*. at 23, 26, the costs of which cannot fairly be assigned to a single Participating TO.

The ISO's proposal allocates Zonal MLCC costs to Zonal Demand. Exh. ISO-22 at 32-3. The allocation reflects the fact that all Demand within the Zone benefits from the maintenance of import capacity into the Zone and the maintenance of reliability of the Inter-Zonal Interfaces. Tr. 240:24 – 241:3 (McIntosh). Staff witness Gross, among others, supports the concept of assessing MLCC costs related to benefits accruing to the entire load in a Zone to all load in that Zone. Exh. S-6 at 20.

Under Attachment E, a unit is committed for System purposes when it is committed or operating to:

1. meet forecast Control-Area Demand; or

2. provide Ancillary Services, if the ISO is procuring Ancillary Services on a Control Area-wide basis.

See Exh. S-18 at 10.

The ISO incurs System MLCC costs in order to keep Supply and Demand in balance in the Control Area. Supply and Demand become out of balance when forward schedules do not match up with (*i.e.*, they deviate from) what appears in real time. For this reason, Amendment No. 60 allocates these costs to those Scheduling Coordinators that deviate from their forward schedules on a Net Negative Uninstructed Deviation

("NNUD") basis, up to a cap. Exh. ISO-22 at 27-29. This cap is important because there are times when the amount of System costs is disproportionate to the level of deviations on the part of Scheduling Coordinators, and an automatic assessment based on NNUD would be unfair. That System reliability costs above the cap are assessed to all Demand in the Control Area and in-state exports is appropriate, "because it proportionately passes those excess costs to all parties placing a demand on the Supply within the ISO Control Area." *Id*. at 29.

The ISO submits that these allocations are specifically within the zone of reasonableness because they rationally match the allocation of charges of the costs incurred with the benefits received. It is true that Local and Zonal waiver denials can provide benefits outside the local area and zone by avoiding cascading outages. It is also true that off-peak usage may be less responsible for cost incurrence than on-peak usage. Greater granularity could, therefore, be possible. As noted above, however, the application of the principles of cost causation is not a precise science, and there is no single just and reasonable rate.

Analogies may sometimes be helpful. A state may have interstates, county highways, and local roads. All of the roads are built to handle peak traffic. The benefits of the interstates are spread throughout the state. The county roads are used primarily in the county, but they do benefit other parts of the state by ensuring that goods from the county can reach the interstate. People in one part of the county may not use roads in another part of the county. The local roads are used primarily in the towns, but they, too, indirectly provide benefits to other parts of the state. Maintenance of the interstate is paid through a toll, with any shortfall covered by a state-wide tax without regard to time or amount of use. The state bills the residents of each county for the maintenance of the county roads, without regard to time or amount of use. The towns are responsible for the maintenance of their roads; how they collect the costs of such maintenance from users is up to them. Obviously, there could be many other ways of paying for road maintenance – but is there anything inherently unjust or unreasonable about the state scheme? So too with Amendment No. 60.

2. Alternative Proposals Are Deficient.

a. Local Category Proposals.

State Water Project witness David Marcus recommends charging Local Minimum Load Cost Compensation charges to the Participating TO in whose service territory the affected Load is located. He also describes this as allocating the charges to the Participating TOs whose transmission facilities are stressed. Exh. SWP-1 at 20:1-7.[9] The ISO's concerns with this approach are purely practical. From an operational standpoint, developing criteria for such allocations would be hugely impractical. Attachment E to Amendment No. 60 illustrates some such problems. One example is a unit located in Participating TO A's service area that is operating to manage overloads on a line between its service area and the service area of Participating TO B. Another example is when Participating TO B takes a line out of service in its service area that creates overloads on a line in Participating TO A's service area. *See* Exh. ISO-21 at 16. Even if this alternative were practical, its existence does not render the ISO's proposal unjust and unreasonable.

[9] Mr. Marcus points out that, under his proposal, Local costs would still be assessed to a Participating TO, but the specific Participating TO to be charged might be different than under the ISO's proposal. Tr. 1121:12-15. *See also* Exh. SWP-1 at 22:17-19: "The designation of the relevant PTO should be based on the location of the affected load, not the generator used to resolve the problem."

b. Zonal Category Proposals.

SWP witness Marcus recommends that certain Zonal charges be allocated on a subzonal level to specific Loads located in specific geographic areas. *See, e.g.,* Exh. SWP-1 at 8:11-16, 9:8-10, 25:4-6, 38:14 – 39:10. Mr. Marcus contends that this allocation is required because the areas outside these subzones do not “cause” the need for the MOWDs. As discussed above, Mr. Marcus’s distinction between causes and benefits is insupportable. His argument must therefore be evaluated as an argument for a greater degree of granularity.

In this case, the value of a greater degree of granularity is outweighed by the impracticality of the proposal. ISO witness Catherine Bodine testified that Mr. Marcus’s proposals could not be implemented without a wholesale revision of the ISO’s scheduling and metering procedures and protocols. Scheduling Coordinators submit Schedules and report Meter Data to the ISO according to Demand Zones, Load groups, and buses. These data points do not correlate with the geographic areas to which Mr. Marcus suggests the costs of Zonal Minimum Load Cost compensation be allocated. *See* Exh. ISO-19 at 21. Ms. Bodine also testified that, even if such a correlation existed, the ISO does not have the software available to make such allocations on an automated basis. Each such allocation would require manual intervention. *Id*.

In response to difficulties in identifying the specific loads responsible for a given constraint on a sub-zonal (yet more than Local) level described by the ISO, SWP and Mr. Marcus have somewhat modified their proposal. SWP has attempted to demonstrate that its pumps can be excluded from Zonal charges because they are in a specific Load group. Tr. 729-731. Mr. Marcus has stated that his proposal should be amended to read "exclude the loads Marcus proposes to exclude, *if* the ISO is aware that that load is in that geographical area." Tr. 1110:12-14 (emphasis added). He further acknowledged that "if the ISO doesn't have the data required to implement a proposal, then it can't implement it." Tr. 1117:16-17. He has suggested that Scheduling Coordinators can have their Loads excluded by submitting schedules that include data identifying the specific Load groups or Scheduling Points necessary to allow the exclusion. Tr. 1111-12. This proposal would introduce an intolerable complexity and inconsistency into the relevant ISO Tariff provisions.

Other parties have characterized Mr. Marcus's proposals in this area as self-interested "carve outs" (Tr. 1369 (Nolff); Pre-Hearing Brief of Southern Cities at 11, n. 5); and results driven (Southern California Edison Pre-Hearing Brief at 3), rather than being based on appropriate cost allocation principles. Mr. Marcus admits that his proposal would provide a free ride to certain load contributing to the congestion and would charge only the load that contributes most to the congestion. As such, he acknowledges that his allocation proposal is imperfect. Tr. 1060-62. Just as SWP does not claim to have a perfect allocation method, the ISO has acknowledged that Amendment 60 is simply one of a number of just and reasonable allocation methods. As discussed above, however, the standard the ISO must reach is not perfection – simply justness and reasonableness – and it is the ISO's proposal that is before the Commission.

The Southern Cities take issue with the ISO's Zonal category to the extent it contains any constraints other than the SCIT nomogram.[10] According to the Southern Cities' witness Mr. Nolff, the other constraints that the ISO categorizes as "Zonal" should be categorized as Local because the constraints in question are caused by "insufficient generation and inadequate transmission infrastructure," and require proximate generating units in order to be addressed. Exh. SOC-1 at 10. In addition, Southern Cities argue that the ISO flouts Commission precedent when it assesses costs on a Zonal basis when the problem being corrected is one of voltage support. *Id*. at 11. Finally, Mr. Nolff criticizes as vague the ISO's criteria for determining which constraints should be considered Zonal and which should be considered Local. *Id*.

Southern Cities examine the question of the proper cost allocation for resolving the constraints the ISO has designated as Zonal solely from the point of view of how to "incentivize"[11] behavior designed to relieve the constraint. The ISO is unaware of any instance in which the Commission has rejected a proposal that allocates costs to the entities that benefit from the services being provided on the basis that an alternative allocation would provide better incentive to resolve the problem. The ISO has assigned constraints to the Zonal bucket, as described in the testimony of Jim McIntosh, when the resolution of these constraints provides more of a regional benefit. Exh. ISO-22 at 23; 25-26. Simply put, this means that entities in addition to the relevant Participating

---

[10] If the Commission should find that the MOWDs associated with constraints that the ISO has categorized as Zonal do in fact benefit more than one entity, Southern Cities argue that their costs should be categorized as System costs, because it is not possible to determine precisely the entities that have transmitted energy over the interface in question. Tr. 1365-66 (Nolff).

[11] *See* Southern Cities Pre-Hearing Brief at 3.

TO both contribute to the need for the must-offer commitment and receive a significant benefit from the efficient resolution of the constraint. For example, the Southern Cities, among many others, benefit from reliable operation of the transmission constraints found in SP15, and it would be unfair for them to avoid any responsibility for the costs associated with these constraints. Exh. SCE-6 at 9. The criteria for distinguishing between Local and Zonal constraints laid out in Exh. ISO-22 at 26-27 are straightforward and do not present difficulties of interpretation.

While the question of whether "proximate units" can resolve certain constraints may have some relevance to incentives or cost incurrence, the relevance of this factor to benefits received is unclear. Moreover, generating units useful in resolving constraints are not always close to the constraint (Tr. 332-33 (McIntosh)); size, for example, is also a significant factor. *See* Tr. 330 (McIntosh); *also* Tr. 1127 (Marcus).

Southern Cities' arguments about Commission precedent with regard to the allocation of Voltage Support costs are inapposite. The case cited by Southern Cities discusses the proper allocation of direct Voltage Support costs. *Cities of Anaheim, et al. v. California Indep. Sys. Operator Corp*., 107 FERC ¶ 61,070 (2004) at P 34. Must offer waiver denials do not result in Voltage Support costs *per se* – they result in MLCC costs for keeping the unit in question online until it is dispatched to provide Voltage Support. Tr. 499-500 (McIntosh). As explained by ISO witness Catherine Bodine,

> A unit that is running at minimum load because of a must offer waiver denial, regardless of the reason of the denial, is not any more providing Voltage Support or being paid for Voltage Support than it is providing or being paid for Ancillary Services or Inter-Zonal Congestion Management. If the unit is indeed called upon to provide Voltage Support, it will be paid separately for that Voltage Support under entirely different portions of the ISO Tariff.

Exh. ISO-19 at 18. *See also* Tr. 824-25.[12] Moreover, denying waivers for purposes of making units available to provide Voltage Support with regard to a given Zonal constraint provides benefits to the system beyond a local area (Tr. 457-58), and therefore the costs related to such denials are appropriately assessed on a Zonal basis.

c. System Category Proposals

Powerex witness Lam argues that assessing System reliability costs based on NNUD is unjust and unreasonable because units are committed based on capacity committed in the Day-Ahead Market to meet projected peak Demand under ISO Operating Procedure M-432C, Exhs. PWX-1 at 7, PWX-3 at 8-10, and are not based on deviations from Final Schedules.[13] As is apparent from M-432C and as Staff witness Patterson properly notes, Exh. S-18 at 18, the ISO's Day-Ahead must-offer commitments are based on Day-Ahead estimates of the degree to which Demand will exceed Supply in *real time*. Although the information may be Day-Ahead, the relevant deviations are those between final Schedules and real-time deliveries. In fact, it is clear from the record that must-offer waiver denial decisions are based on estimated data of real-time loads (which are in turn based on historical experience) for the day on which the units will be required to be online, and not based on final Day-Ahead Schedules. Tr. 570-71. It is thus misleading to characterize the MOWD process as purely a "Day-Ahead" process. Nothing in Powerex's description supports a conclusion that the ISO's proposal is unjust or unreasonable.

---

12 Voltage Support is, of course, an Ancillary Service under the ISO Tariff. *See* Item by Reference 1 at sheet 303; Tr. 737-38 (Bodine). As such, the discussion of the difference between Ancillary Services costs and MLCC costs related to the provision of Ancillary Services in Section IV(B), below, is relevant here.

13 Powerex's specific alternative proposal is discussed in Section I(K), below.

Powerex also contends that the allocation would impose duplicate penalties on generators and scheduled interchanges, which are subject to Uninstructed Deviation Penalties ("UDPs"). Exh. PWX-1 at 6. In addition, Powerex attempts to draw a contrast between UDP, under which "faultless" Scheduling Coordinators do not receive penalties, and the Amendment No. 60 allocation, under which Scheduling Coordinators may be "penalized" for failing to perform schedules for reasons beyond their control. Tr. 811-13.[14] ISO witness Catherine Bodine explained that these mechanisms serve two different purposes:

> [I]t is a different circumstance with UDP than with this allocation. UDP is meant to penalize units for behavior that has a detrimental effect on the ISO and, to the extent that they're not in control of that behavior, we don't want to penalize them where the MLCC isn't necessarily meant to penalize deviators, its meant to allocate the costs needed to maintain grid reliability. So it's a different reason and the same reasoning wouldn't apply to both.

Tr. 812:16-24.

With regard to the question of "faultless" Scheduling Coordinators bearing a share of NNUD costs, ISO witness Jim McIntosh explained at the hearing that regardless of whether a Scheduling Coordinator deviates from an interchange schedule for reasons beyond its control, that Scheduling Coordinator is still causing the deviation, and the ISO still must, in real time, replace the energy that was expected to appear through the interchange transaction. Tr. 531:4-8; 534:15-20. In addition, Ms. Bodine explained that if "faultless" Scheduling Coordinators were excused from paying NNUD with regard to interchange failures over which they had no control, the costs of replacing

---

[14] Of course, since "faultless" Scheduling Coordinators do not receive a penalty under UDP, this group, at least, cannot be considered to have been "penalized" twice if they do, in fact, pay their share of NNUD.

the interchange energy would fall to other Scheduling Coordinators experiencing NNUD, or possibly to the System bucket, should the NNUD cap be exceeded. Tr. 817. Moreover, ascertaining whether a Scheduling Coordinator was or was not at "fault" for its deviation would burden the ISO with judgement calls and would, as explained by ISO witness Bodine, entail costs for the ISO, possibly including dispute resolution costs. Tr. 817-18. Ms. Bodine explained that the ISO does not have the data needed to render the Powerex proposal to exempt Scheduling Coordinators whose deviations are beyond their control "easily implementable." Tr. 813:20-21.

If Powerex believes that generators and scheduled interchange are unfairly singled out for Uninstructed Deviation Penalties, its remedy is in proceedings related to those penalties. The development, approval, and implementation of penalties for uninstructed Schedule deviations, however, has no bearing on this proceeding, which addresses not penalties, but the allocation of costs.

D. Whether the "incremental cost of Local" approach for determining the allocation of MLCC costs between "System" and "Local" categories is just and reasonable.

1. The "Incremental Cost of Local Approach" is Just and Reasonable.

The ISO has proposed that in cases where the same Generating Unit was committed for both a Local and a System need, only the additional cost of committing and operating that particular Generating Unit beyond the cost of operating the least expensive Generating Unit that could have been committed for the System need but for the additional Local need – *i.e.*, the "incremental cost" of that unit – should be allocated to the Participating TO. *See* Exh. ISO-20 at 18.

The mechanism by which this incremental cost is calculated is for the ISO to operate its Security Constrained Unit Commitment ("SCUC") application in two passes:

> The first pass will consider only system needs and commit Generating Units on a least-cost basis to meet those needs. The second pass will include those Generating Units needed for local reliability requirements as well as Control Area needs. The "incremental cost" between the second run and the first run represents the additional cost that must be incurred to commit particular Generating Units needed for local reliability instead of committing the least expensive Generating Unit available within the ISO Control Area.

Exh. ISO-20 at 18:9-16.

In other words, the system determines whether, in the absence of the Local problem, another Generating Unit would have to have been committed in order to address a System need. If the answer is in the affirmative, then it cannot reasonably be denied that the Generating Unit is serving a System as well as a Local purpose, and users of the entire transmission system are benefiting from the commitment of the Generating Unit. It is thus fully consistent with cost causation principles that only the incremental costs be assigned to the local Participating TO.

PG&E witness Goldbeck (testifying also on behalf of the California Public Utilities Commission and the Independent Energy Producers Association) objects to the local incremental cost approach because it mutes economic incentives (Exh. JNT-1 at 6) and harms PG&E rate payers economically. Tr. 973:19-23; 979:6-24. The ISO believes that in this case it is more important to maintain a consistent approach to cost causation. Consider the following hypothetical: On Day 1 the ISO has a System need for which it issues a MOWD for Unit X with a cost of $50. That cost is assessed to the System bucket. On Day 2, the System need persists. In addition, a local need arises. The ISO therefore issues a MOWD for Unit Y with a cost of $60, but because Unit Y is available, it can issue a waiver for Unit X. If the entire cost of Unit Y were placed in the Local bucket, the System bucket would get a free ride on Day 2, even though it was receiving the exact same benefits its received on Day 1. The Local bucket, however, would be paying $60 even though it imposed only $10 worth of additional costs (although it may be receiving more than $10 worth of benefits). Under the local incremental approach, of course, the local load would also be paying its share of the System bucket.

As noted above, the assignment of the Local bucket to the Participating TO in whose Service Territory the Generating Unit is located is consistent with the allocation of the costs of RMR Units under the ISO Tariff. So too is the local incremental approach. The Energy generated by RMR Units must be sold in the ISO's markets or in a bilateral transactions. Tr. 849-50 (Bodine). This is essentially its value as a system-wide resource – providing Imbalance Energy. The RMR Owner bills only the RMR Contract amount net of the Energy cost (essentially the incremental amount attributable to the local need) to the ISO to be invoiced to the Responsible Utility, *i.e.*, the Participating TO. *See* Tr. 856-57 (Bodine). These mechanisms, as part of the ISO Tariff and RMR Contracts, have been approved by the Commission as just and reasonable, *see, e.g.*, *California Indep. Sys. Operator Corp*., 90 FERC ¶ 61,345 (2000) and are no less so here.

2. The Local Incremental Approach Will Require Modification for Retroactive Application.

Should the Commission determine that the Amendment No. 60 allocation proposal be made effective as of July 17, 2004,[15] the incremental cost of local mechanism will require some modification for the period between July 17 and

15 This issue is discussed below in Docket No. EL04-103 Issue II.

September 3, 2004 (the date on which SCUC became operational). ISO witness Mr. McIntosh, explains that the ISO cannot apply the incremental cost methodology retroactively to the Local MLCC in the same manner as it is applied through SCUC contemporaneously with MOWD determination. Exh. ISO-22 at 40. Instead, the ISO proposes to use the process described below:

> 1. The ISO will first determine which units were committed through the must-offer waiver denial process on a given day by querying the operations records. This information will also indicate what specific reason the unit was committed and, therefore, whether the Minimum Load Costs should be classified as Local, Zonal, or System costs.
>
> 2. Next, the ISO will capture the operating conditions (generation schedules, Ancillary Service Schedules, intertie Schedules, Path 15 and Path 26 limits, Demand forecasts, and fuel prices) for that day, either by (a) retrieving the SCUC save case, which contains all that information, or by (b) retrieving the information from other databases, including the Scheduling Infrastructure ("SI") database. Because the SCUC was not put into service until September 2, 2004, for trade date September 3, 2004, the ISO will have to use method (b) to re-create operating conditions from July 17, 2004 through September 2, 2004.
>
> 3. The ISO will run the SCUC for that day with the units committed for System and Zonal reasons forced on, and with the units that were actually committed for Local reasons de-committed but available to be committed for the purposes of the SCUC run. If some of the units that were required for System and Zonal reasons had been committed for Local reasons, then SCUC will re-commit those units when it performs this run. This run will provide the Minimum Load Costs for those units that operated for System and Zonal reasons. For the period before SCUC was put in service on September 2, 2004, the calculation of System and Zonal Costs will reflect the ISO's "first come, first-served" process for committing Generating Units under the must-offer obligation. Consequently, the System and Zonal costs for those units expressly committed by the ISO for System and Zonal purposes and forced on in SCUC will not likely be the optimal level of costs to meet these classes of needs, but will reflect what actually occurred. After September 2, 2004, the SCUC commitment for System and Zonal reasons should be the optimal cost, so when SCUC is re-run to determine the net incremental cost, the System and Zonal costs determined for this period should be the same as those originally determined by SCUC when it initially determined which must-offer units to commit to meet the System and Zonal requirements.

Id. at 40-42.

The ISO has considered its interim (*i.e*., July 17-September 3, 2004) method of calculating the incremental cost of local carefully, and believes that while it is not as accurate as the fully-realized post-SCUC method, the results of this allocation would still be superior to the pre-Amendment 60 alternative.

E. Timing Issues

1. Whether non-Local MLCC costs should be allocated on a daily or monthly basis.

Although the ISO proposed allocating MLCC costs on a monthly basis, it has indicated that it would not oppose allocating them on a daily basis. Exh. ISO-20 at 36; Tr. 852:8-10 (Bodine).

2. Whether non-Local MLCC costs should be assessed only to loads occurring in the peak time periods for which Must Offer Waivers are denied.

a. Non-Local MLCC Costs May Be Just and Reasonable Without Being Limited to Peak Periods Because Off-Peak Loads Benefit from MOWDs.

The ISO has not proposed that non-Local MLCC costs be assessed according to time of use. As described in the testimony of Jim McIntosh, the must-offer obligation is designed "to ensure that the ISO has sufficient capacity reserves to deal with a Contingency,[[16]] particularly the failure of a major transmission line or Generating Unit. A Contingency may occur at any hour of the day, off or on peak." Exh. ISO-21 at 6:13-16. Moreover, a failure of the system during a peak period could have consequences extending into a non-peak period. Non-peak users thus benefit from non-Local MLCC.

[16] A Contingency is defined in the ISO Tariff as "Disconnection or separation, planned or forced, of one or more components from an electrical system." ISO Tariff Appendix A, Master Definitions Supplement (Item by Reference 1, Sheet 308).

The ISO has acknowledged that its need to call upon must-offer units historically has arisen in peak periods, Exh. ISO-22 at 35, and the ISO does not dispute that it looks to peak load in evaluating its need for must-offer units. An allocation of non-Local MLCC costs only to Loads occurring during certain peak periods may thus be just and reasonable. It does not follow, however, that a failure to so allocate non-Local MLCC costs is unjust or unreasonable. In a recent decision involving many of the same parties as this proceeding, the Commission firmly rejected arguments that Court and Commission precedent dictate "that a rate methodology is not reasonable if it fails to differentiate cost-causation and thus pricing between on-peak and off-peak users." *California Indep. System Oper. Corp.,* 111 FERC ¶ 61,337 at P 85 (2005). The Commission also considered it relevant to consider how many parties would benefit from the use of time-sensitive rates. *Id.* at 83. In this proceeding, the only party seeking time-of-use rates, and apparently the only party that would benefit therefrom, is SWP.

Mr. McIntosh explained at the hearing that off-peak loads benefit from the commitment of must-offer generation. Tr. 142. For example, certain planned outages occur during off-peak periods and require must-offer commitments. Tr. 182, 393. More generally, however, as noted above, if the ISO fails to address a constraint, and a contingency during a peak period causes a system failure, that system failure may interrupt service well into non-peak periods. Tr. 391-92. Because non-peak users receive significant benefits from MOWDs, the failure of Amendment No. 60 to employ time-of-use pricing does not render it unjust or unreasonable.

b. Time-of-Use Pricing for Must-Offer Charges Does Not Provide Significant Economic Incentives.

Among the arguments advanced by SWP witness Marcus in support of time-of-use pricing is the need to provide incentives for Load to switch to off-peak. Tr. 1056. With the exception of SWP and a few like-situated entities, however, must-offer charges are not assessed to end-use loads that can respond to such price signals. Time-of-use must-offer charges would have to be reflected in time-of-use retail rates in order to provide any sort of incentive to Load shifting and SWP has presented no evidence that the metering requisite equipment is in place or that the value of time-of-use MLCC charges would constitute a sufficient portion of rates to render the ISO's proposal unjust and unreasonable. As to SWP, it already operates its pumps off-peak due to time of use Energy savings. Tr. 1079:10 – 1081:11. There is thus no evidence that on-peak pricing would provide any beneficial economic incentives.

3. If non-Local MLCC costs should be allocated only to loads occurring in the peak time periods for which Must Offer Waivers are denied, how should the peak period be defined?

The ISO had not taken a position in testimony regarding the appropriate definition of a "peak period" in the context of non-Local MLCC costs allocated solely to loads occurring in peak periods. The ISO agrees with Staff witness Black, however, that the adoption of the Western Electric Coordinating Council ("WECC") definition of peak is appropriate because it is consistent with the reliability nature of the must-offer requirement. *See* Ex. S-1 at 15. Moreover, he evidence is too inconclusive to support any other definition. Indeed, seasonal variations of peak use would render the choice of a nonarbitrary definition difficult at best.

F. Whether ETC Schedules should be exempted from all or some Zonal MLCC costs.

Amendment No. 60 does not exempt Existing Contract Schedules from Zonal MLCC. As the holders of Existing Contracts benefit from the real-time reliability of the Inter-Zonal Interfaces, and there has been no evidence introduced to support a finding that it is not just and reasonable to include them in the allocation of Zonal MLCC, they are reallocated their share in the same manner as other demand within the Zone. It isbecause Existing Contracts usually provide the Existing Rightsholder with scheduling rights that the Existing Rightsholder is exempt from Usage Charges (congestion charges in the Day-Ahead and Hour-Ahead Markets). Existing Contracts are assured the right to schedule their transactions, up to the contracted capacity, without additional costs. Zonal MLCC costs, incurred when a unit is committed because of the potential for real-time congestion, are, however, not congestion charges; they are not costs for scheduling the transactions. This is explained in the testimony of Catherine Bodine, Exh. ISO-19 at 16-17. They are charges incurred to maintain the real-time reliability of the transmission grid, in particular at the Inter-Zonal Interfaces. If the ISO lacks adequate resources to resolve Inter-Zonal Congestion in real-time, the Existing Contract schedule may be subject to curtailment according to the terms of the contract, *see* ISO Tariff Dispatch Protocol § 8.3; Schedules and Bids Protocol § 3.3 (Item by Reference 1, Sheets 477, 549-51). If the Inter-Zonal Interface fails in real time, all users suffer, including those users with Existing Contract rights. Consequently, Must-Offer Waiver Denials provide a very real benefit to the Existing Rightsholders that is not provided by the Existing Contracts.

G. Whether Wheel-through schedules should be exempted from all or some System MLCC costs.

For the purpose of this discussion, wheel-through Schedules constitute transactions for which the source is outside of the ISO Control Area and the sink is also outside the ISO Control Area. For ISO operational purposes, therefore, a wheel-through comprises an import and an export. Under Amendment No. 60, exports may be billed a portion of system MLCC. Specifically, wheel-through Schedules would only be assessed MLCC costs if 1) the ISO is incurring Minimum Load Costs for System reasons, 2) there are excess Minimum Load Costs beyond those allocated to Net Negative Uninstructed Deviations, and 3) the wheel-through Schedules were for Energy exported to another Control Area in California. Ex. ISO-20 at 33-34.

As Mr. McIntosh testifies, wheel-throughs impose reliability requirements on the ISO. Moreover, the Commission, when it first determined the allocation of MLCC, determined that exports – as users of the transmission grid – benefited from the costs of maintaining reliability, including MLCC. *San Diego Gas & Electric*, 97 FERC ¶ 61,293 at 62,363, 62,370. Nothing has occurred or been brought to light to change that determination. There is, therefore, no evidence that the failure to exempt wheel-throughs renders the ISO's proposal unjust or unreasonable.

H. Whether Pump Loads should be exempted from all or some MLCC costs.

The ISO does not contend that it would be unjust or unreasonable specifically to exempt certain pump loads from some MLCC costs. Amendment No. 60, however, does not attempt to examine the specific contribution of any specific loads to MLCC costs. To do so would create a very complex system, which would require continual amendment as new constraints arose. For example, the nature of the South of Lugo constraint has changed with transmission enhancement, Exh. ISO-22 at 7; and the Sylmar constraint was the product of the construction of a system enhancement. *Id*. If a new transmission enhancement created a temporary constraint, the ISO would have to file a tariff amendment to assign the costs to the specific loads that might be said to receive benefits from the MLCC costs involved.

Pump loads, like all other loads, benefit from transmission reliability. Under Amendment No. 60, pump loads will be relieved of Local and many Zonal MLCC costs. In light of the reliability benefits received, it is just and reasonable to treat pump loads like other loads within the Zone.

I. Whether load serving entities ("LSEs") should be permitted to self-provide local generation (or inertia) and thereby avoid SCIT related MLCC costs.

Southern Cities have presented testimony in favor of creating a system for allowing Load Serving Entities to self-provide their load-ratio share of generation, or inertia, to avoid SCIT-related MLCC costs. "SCIT" is the Southern California Import Transmission nomogram. In the testimony of Mr. Tang, Exhs. SOC-28 and 64, Southern Cities argue that the ISO should allow LSEs to self-provide inertia in the place of paying their demand-based share of MLCC costs. Exh. SOC-28 at 4. Mr. Tang testifies that "[s]ince the SCIT nomogram is resolved by increasing generation levels in SP15 [the area south of Path 15], LSEs in SP15, consistent with cost causation principles, should have the option of paying their share of SCIT-related costs or self-supplying generation to relieve their share of the problem." Exh. SOC-28 at 4.

Southern Cities' self-provision of inertia proposal constitutes a somewhat self-serving carve-out from the over-all Amendment No. 60 allocation proposal similar to those to which Southern Cities themselves take exception in the proposals of other parties. *See, e.g.*, Tr. 1369 (Nolff);[17] Tr. 1450:18-20; 1452:8-11 (Tang); Southern Cities Pre-Hearing Brief at 11, n. 5. The immediate beneficiaries of this proposal would be generators capable of self-provision in the area covered by the SCIT nomogram – *i.e.*, those in SP-15. Southern Cities do not propose to apply the mechanism to any other constraint. Tr. 1447-48 (Tang). Indeed, as discussed above, Southern Cities argue that no other constraint should be categorized as Zonal in the first place. Ex. Nos. SOC-1 at 7, SOC-28 at 4; Tr. 1442-43 (Tang); Tr. 1364-65 (Nolff). The benefits of any such mechanism, therefore, would accrue to a limited number of entities. Tr. 1448:22-24. The costs of adopting this proposal would, however, and contrary the opinion of Mr. Tang, Exh. SOC-28 at 8, be substantial, and would be spread among entities for whom the proposal provides at best negligible benefit.

There are in any case serious obstacles to the implementation of an inertia self-provision mechanism. As described in the testimony of Jim McIntosh, the ISO does not have sufficient information to determine the appropriate share of inertia for each Load Serving Entity. Exh. ISO-21 at 11. The SCIT nomogram determines the ISO's Generation requirement through historic flows, not through current Load. Historic flows are not easily broken down into LSE increments. *Id*.

---

17 Mr. Nolff describes certain carve-outs he claims are proposed by SWP witness David Marcus as "difficult to administer and difficult to quantify." Tr. 1369:1-2. The same criticism could be applied to the self-provision of inertia proposal.

In addition, the SCIT Generation requirement is determined primarily on a Zonal basis, whereas MOWDs may also be made for Local reliability reasons. The ISO cannot know how much additional Generation is required by the SCIT nomogram until after it has made commitments for Local reliability requirements. By this time, it would "too late to implement in any feasible manner the type of self-provision program envisioned by [SOC witness] Mr. Tang." Ex. ISO-21 at 11. Fixing each LSE's share in advance (*i.e.*, before making the Local unit commitments), however, would lead to a likelihood of over-Generation. *Id*. at 12.

Mr. Tang opines that the new self-provision mechanism will be "fairly simple and . . . could be readily implemented by the ISO." Exh. SOC-28 at 8.[18] He also notes, however, that in developing such a mechanism, he would "defer to the ISO in formulating a mechanism consistent with its operating process," Exh. SOC-28 at 9, and that he "is obviously not as familiar with the ISO's operations as its employees are." Exh. SOC-64 at 5. Contrary to the optimism of Mr. Tang, Ms. Bodine, a key ISO employee involved in the ISO's settlement processes, has testified that "creating an entirely new process to address, essentially, one constraint would be burdensome and counter productive in the current environment where the ISO's settlements systems are being overhauled [as part of MRTU]." Exh. ISO-19 at 22. ISO witness Mr. McIntosh likewise explained that developing and implementing the Southern Cities' self-provision proposal would take a couple of months, and be followed by the necessary

[18] In spite of his expressed opinion that creating the new self-provision mechanism would not tax the ISO's resources, Mr. Tang acknowledged that "[o]bviously implementing a new procedure . . . will involve some resources," Tr. 1454:23-25; and that there is "understandable reluctance from the ISO's standpoint to implement anything new at this time." Tr. 1456:5-6.

development of software changes. Tr. 499:4-7. Moreover, Mr. McIntosh explained that the ISO personnel needed to develop the Southern Cities' proposal are the same individuals currently involved in the MRTU process, which would be "a detriment to getting that program here on time." Tr. 499:7-11.

In addition, while, as described above, the benefits of such a new process would inure to a few Market Participants, Ms. Bodine notes that the costs would be spread across all rate payers. Exh. ISO-19 at 22. Similarly, any delay in MRTU that resulted from the ISO having to devote resources to develop this proposal would constitute a delay in benefits to the entire market. Tr. 1459:20-24 (Tang).

For these reasons, the ISO opposes the Southern Cities' proposal for the self-provision of inertia as impractical and constituting a carve-out benefiting the few at the cost of the many.

J. How should the ISO treat MLCC costs related to must offer waivers denied for more than one reason?

As noted in the testimony of SWP witness Marcus, during the timeframe between July 17, 2004 (the refund effective date for EL04-103) and August 26, 2004, there were several instances of MOWDs being attributed to more than one cause. Exh. SWP-18 at 34. These dual categorizations are reflected in the February 18, 2005 version of Exh. ISO-18. The dual categorizations fall into three types: System/SCIT, SCIT/South of Lugo, and Sylmar/Victorville-Lugo. Such dual categorizations are only a problem to the extent costs must be retroactively reallocated pursuant to the July 17, 2004, refund effective date. As Ms. Bodine notes in her testimony, problems with the ISO's data and categorization have largely been resolved. Exh. ISO-19 at 11.

Under the ISO's MLCC allocation proposal, only dual categorizations that include more than one cost bucket are problematic. The System/SCIT example from above represents this type of record, where the System cost bucket and the Zonal (SP15) cost bucket are both implicated by the two reasons cited. In this instance, a method for apportioning the single MLCC value implicating the two cost buckets represented by this dual-reason waiver denial will have to be developed. The other two types of dual categorizations, SCIT/South of Lugo and Sylmar/Victorville-Lugo, consist of reasons that are both in the proposed Zonal cost bucket and are both in the SP15 zone, so they do not present any allocation difficulties – *i.e.*, both of the individual causes in each instance are to be allocated in the same manner. Thus, should the ISO's proposed allocation methodology be approved by the Presiding Judge and the Commission, no corrective measures need to be taken for these dual categorizations.

Under proposals of other participants, however, the individual causes for each of the three types of dual categorizations may be divided among different allocation methods. Exh. SWP-1 at 34. SWP presents two possible options for correcting the dual categorizations: to divide the MLCC costs associated with each of the dual categorizations equally between the two categories (a 50-50 split), and the re-categorization of each of the instances of dual categorization according to what SWP calls "cost causation principles." *See* Exh. SWP-1 at 39-40. The ISO takes no formal position on these options, but notes that the data it has available would make a precise re-categorization of these instances problematic.

K. Whether the ISO should allocate System Minimum Load Costs based on deviations between metered load and Day-Ahead scheduled load (where the total Day-Ahead scheduled load deviates from the total metered load by more than a 5 percent threshold).

Powerex witness Jeff Lam describes an alternative to the ISO's proposed allocation of System costs to net negative uninstructed deviations ("NNUD"). Mr. Lam suggests that a better approach would be to assess System MLCC costs based on the difference between the total Day-Ahead scheduled Load and the total metered Load, at times when the total Day-Ahead scheduled load is less than 95% of the total metered load. In those instances, an individual Scheduling Coordinator "should pay a portion of the System Minimum Load Costs based on a pro rata share of the shortfall."
Exh. PWX-1 at 10:5-6.

The ISO took no position in pre-filed testimony on whether the Powerex proposal might be just and reasonable. At the hearing, however, ISO witness Jim McIntosh indicated that implementing the Powerex proposal would expend ISO resources in terms of software development, and added that "any software work we do now, has the potential to impact the delivery of MRTU." Tr. 542:9-13. For this reason, the ISO believes the implementation problems of the Powerex proposal argue against its adoption.[19]

[19] As described above in Section I(C), Powerex's arguments against the ISO's proposed allocation for System MLCC costs to NNUD do not withstand scrutiny.

L. Whether Start-Up and Emissions costs of units denied must offer waivers should be allocated in the same manner as those associated with Minimum Load Cost Compensation ("MLCC") and whether a revision to the allocation of these costs even should be addressed in this proceeding.

Amendment No. 60 does not propose to allocate Start-Up and Emissions Costs associated with MOWDs in the same manner as it has proposed with regard to MLCC costs, and in fact proposes no change in the allocation of such costs. The only matter set for hearing was the ISO's cost allocation proposal. *See* 108 FERC ¶ 61,022 at P 63. Accordingly, issues concerning the allocation of Start-Up and Emission Costs are beyond the scope of the hearing.

If the Presiding Judge concludes this issue is within the scope of the hearing, he should find that the existing allocation of Start-Up and Emissions Costs remains just and reasonable. As explained in the testimony of Ms. Bodine, Start-Up and Emissions Costs are small in comparison to MLCC costs, and it would not be a worthwhile allocation of the ISO's limited resources to create and maintain a complex system to track and allocate these costs. Exh. ISO-20 at 21-22. Staff witness Patterson's argument that MLCC costs must be allocated in the same manner as Emissions and Start-Up Costs, Exh. S-18 at 23-27 does not bear scrutiny. The Commission order cited by Ms. Patterson as requiring that MLCC costs be allocated in the same manner as Emissions and Start-Up Costs, *San Diego Gas & Electric, et al.,* 97 FERC ¶ 61,293 can be interpreted to direct that the manner in which Emissions and Start-Up Costs were allocated *at that time* was appropriate for MLCC costs, as well. There is no reason to interpret this order to mean that the three types of costs should be allocated in the same manner *for all time*. It is by no means clear that the Commission, in light of the information in Ms. Bodine's testimony, would still consider it necessary to allocate the three types of costs in the same manner. Indeed, if the Commission had considered it necessary to do so, it would have stated as much in the order accepting Amendment No. 60 for filing. Instead, this order is silent on Emissions and Start-Up Costs related to must-offer, despite the fact that Amendment No. 60 proposes no change to such allocation.

Nonetheless, should the Presiding Judge determine that the method by which Emissions and Start-Up Costs are allocated is an appropriate subject matter for this proceeding, the ISO does not oppose the alternative means of allocating Start-Up Costs advocated by PG&E (Exh. PGE-4 at 5-6), SWP (Exh. SWP-1 at 40-41), and the Commission Staff (Ex. S-18 at 26-27), as they do not present any significant implementation difficulties for the ISO. Exh. ISO-19 at 19.

With regard to the allocation of Emissions Costs, however, the situation is not so simple. It is not possible for the ISO to separate out the Emissions Costs properly associated with MOWDs from those related to any other ISO Dispatch. Exh. ISO-19 at 20. Ms. Bodine further explained on the stand that although it might be possible for Scheduling Coordinators to submit Emissions Costs broken out between MOWDs costs and other Emissions Costs, there would be no way for the ISO to verify such figures. Tr. 756:14 – 757:12. That being the case, although the Emissions Costs allocation alternatives (*i.e.*, the same mechanisms suggested by PG&E, SWP, and the Commission Staff with regard to Start-Up Costs) are not complicated (Exh. ISO-19 at 19), the ISO simply cannot determine to which Emissions Costs these allocation methodologies should be applied. For this reason, the ISO believes Emission Costs associated with MOWDs should continue to be allocated in the same manner as all other Emissions Costs.

II. Attachment E Issues

A. Whether Attachment E as included in the ISO's original filing of May 11, 2004 should be deemed part of Amendment 60 to the ISO Tariff as filed.

As indicated above, the ISO would not object to "deeming" Attachment E as already a part of the tariff amendment filing, in order to facilitate including these criteria as part of what constitutes its proposal in this proceeding, and as subject to a refund effective date of July 17, 2004. Tr. 870:20-871:5 (Bodine).

B. Whether the criteria used by the ISO to classify units committed under the Must Offer Wavier Denial (MOWD) process should be included in the ISO Tariff.

As noted in its testimony, Exh. ISO-19 at 7-8; Tr. 867:23-25 (Bodine), the ISO does not object to including such criteria in its tariff in a filing in compliance with a Commission order at the conclusion of this proceeding.

III. Whether the proposed definition of Reliability Services Costs is just and reasonable.

During the stakeholder process, Southern California Edison requested that Minimum Load Costs allocated to a Participating TO due to a Local need in its service area be characterized as Reliability Services Costs. The ISO agreed, and included the following definition of Reliability Services Costs in its tariff:

> The costs associated with services provided by the ISO: 1) that are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff. Reliability Services Costs include costs charged by the ISO to a Participating TO associated with

> service provided under an RMR contract (Section 5.2.8), local out-of-market dispatch calls (Section 11.2.4.2.1) and Minimum Load Costs associated with units committed under the must-offer obligation for local reliability requirements (Section 5.11.6.1.4).

ISO Tariff Appendix A, Master Definition Supplement (Item by Reference 1 at Sheet 344).

TANC has presented testimony criticizing the proposed definition of Reliability Services Costs, both on the grounds that no such definition is necessary (Exh. TNC-1 at 6) and that the proposed definition is vague and overly-broad. *Id*. at 6-7. SMUD, as well, presents testimony opposing including the definition in the ISO Tariff. Exh. SMD-1 at 28.

The question of whether the term "Reliability Services Costs" should be defined in the ISO Tariff is beyond the scope of this proceeding. In the order setting this matter for hearing, the Commission stated:

> Generally, we find it reasonable for the CAISO to define costs incurred in order to maintain the reliability of the grid as reliability costs. However, because we have set for hearing the reasonableness of the CAISO's proposed cost allocation methodology, *this definition* will be subject to the outcome of that hearing.

California Indep. Sys. Operator Corp., 108 FERC ¶ 61,022 at P 68 (emphasis added). Only the content of the definition is at issue.

As to TANC's second point, that the definition is vague and overly broad, the definition provides two criteria for the costs to be included: they are "deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area" and are "billed by the ISO to the Participating TO pursuant to the ISO Tariff." TANC's only specific criticisms appear to be that "the ISO will have unfettered discretion to determine whether a cost is reliability related without the obligation to obtain Commission approval for its determination that the cost is reliability related or the allocation of such cost," Exh. TNC-1 at 11, and "[u]nder the proposed definition of 'Reliability Services Costs,' . . . the cost allocation to Participating TOs can be modified at the discretion of the ISO," *id.* at 12. If the second criticism is meant to suggest that the ISO has the discretion to create new charges to Participating TOs, it fundamentally misunderstands the provision. The definition is solely a definition; it does not create a charge or a formula rate. Before the ISO can bill any costs to the Participating TO through the Tariff, the ISO must obtain Commission approval.

It is the requirement to obtain Commission approval that provides the necessary limits on ISO discretion. During that process, the ISO will need to present its justification for any allocation of costs to the Participating TOs. If intervenors believe that the cost is not reasonably related to the reliability of the Control Area, they are free to make that argument to the Commission; the Commission will ultimately determine how, and why, the costs are allocated.

IV. Ancillary Services Issues

A. Does the ISO have the authority to commit a Generating Unit under the Must Offer Obligation to provide Ancillary Services?

Under Section 5.11.1 of the ISO Tariff (Item by Reference 1, Sheet 184A), all Generators subject to the Must-Offer requirement must bid their Generating Units into the ISO's real-time Energy market. As a result, those Generating Units will be online and available to provide Imbalance Energy to replace Operating Reserves (Ancillary Services) dispatched by the ISO pursuant to Section 2.5.22.9 of the ISO Tariff. Moreover, under Amendment No. 60, because Generators continue to recover Minimum Load Cost Compensation costs if providing Ancillary Services from such units, the

Generators have every incentive to bid those units into the ISO's Ancillary Service Markets. In addition, if necessary, the ISO may purchase Ancillary Services from such units under Section 2.5.22.1 of the ISO Tariff (Item by Reference 1, Sheet 99), if its Operating Reserves are depleted by the need to provide Imbalance Energy.

Under Section 5.11.6 of the ISO Tariff (Item by Reference 1, Sheet 184C), Generators may seek a waiver of the Must Offer requirement. Section 5.11.6.2 sets forth two primary criteria for the granting of such waivers, one of which is the need to meet Operating Reserve requirements. Operating Reserves under the WECC Minimum Operating Reliability Criteria are the equivalent of the ISO's Regulation, Spinning Reserves, and Non-Spinning Reserve Ancillary Services. Tr. 737 (Bodine). Operating Reserves are defined by the ISO Tariff as Spinning and Non-Spinning Reserves. In other words, under Section 5.11.6.2 of the ISO Tariff (Item by Reference 1, Sheet 184F.02), the ISO should not grant, *i.e.*, it should deny, a waiver if it believes if will have inadequate Ancillary Services.

Further, to the extent the ISO is operating within the criteria of Section 5.11.6.2 in granting waivers, there are no tariff limitations on the reliability concerns that the ISO may take into account in determining which specific waiver requests to grant and which to deny. An anticipated lack of Ancillary Services bids is such a reliability concern.

B. Should Scheduling Coordinators who self-provide Ancillary Services be allocated costs of MLCC for Ancillary Services?

As described above, ensuring that there are sufficient units available to provide adequate Operating Reserves is fundamental to the reliability of the transmission system. If there is no capacity available in the ISO's Ancillary Services markets to meet Operating Reserve requirements after accounting for self-provision of Ancillary

Services, the ISO could still face a System Emergency despite the self-provision. All users of the grid thus benefit from, and should share, the MLCC due to the commitment of units in order to ensure the availability of adequate Ancillary Services.

The contention that those self-providing of Ancillary Services are thus double-billed for Ancillary Services is erroneous. As explained in the testimony of Catherine Bodine, Exh. ISO-19, Ancillary Services procured through ISO markets are *capacity* services, whereas Minimum Load Cost compensation is a payment for *Energy*. Exh. ISO-19 at 13; Tr. 742. If the Ancillary Services bid of a MOW-denied unit is selected in the market, such that the MOW-denied unit actually provides Ancillary Services, it would be paid for them just like any other provider. Those costs would be billed, pursuant to ISO Tariff Section 2.5, only to Scheduling Coordinators that had not fully self-provided Ancillary Services. *Id*. at 14. Scheduling Coordinators that self-provide Ancillary Services would never bear the cost of Ancillary Services payments to an MOWD unit.

Docket No. EL04-103

I. Whether the manner in which the ISO allocated Must Offer Obligation related charges, including MLCC costs prior to October 1, 2004 was just, reasonable and not unduly discriminatory.

The ISO has stipulated that it was no longer just and reasonable as of July 17, 2004, to allocate the entirety of MLCC to Control Area Gross Load and Demand served by exports from the ISO Control Area to other Control Areas within California. *See* Stipulation No. 3, filed with the Commission on July 29, 2005.

II. Whether the refund effective date of July 17, 2004 should be conditioned in any way.

As noted in the Testimony of Catherine Bodine, Exhibit No. ISO-20, the ISO does not oppose the refund effective date of July 17, 2004. Exh. ISO-20 at 40.

CONCLUSION

Wherefore, the ISO respectfully requests that the Presiding Judge find Amendment No. 60 to be just and reasonable, as discussed above.

Respectfully submitted,

/s/ Michael E. Ward

Charles F. Robinson General Counsel Anthony J. Ivancovich Senior Regulatory Counsel Stephen A. S. Morrison Corporate Counsel The California Independent System Operator Corporation 151 Blue Ravine Road Folsom, CA 95630 Tel: (916) 608-7049 Fax: (916) 608-7296	J. Phillip Jordan Michael E. Ward Julia Moore Swidler Berlin LLP 3000 K Street, Suite 300 Washington, DC 20007 Tel: (202) 424-7500 Fax: (202) 424-7643

Dated: August 16, 2005

CERTIFICATE OF SERVICE

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

Dated at Folsom, California, on this 16th day of August, 2005.

/s/ Stephen A. S. Morrison
Stephen A. S. Morrison