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)**

PRE-TRIAL BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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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 March 10, 2005, order of the Chief Administrative Law Judge. This Pretrial Brief addresses the issues on which the ISO filed testimony in this proceeding and provides additional discussion on other issues identified in the Joint Stipulation of Issues.

The ISO reserves its rights to cross-examine on all matters listed in the Joint Stipulation of Issues, and to brief the entire evidentiary record when the hearing ends.

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

PROCEDURAL HISTORY

The participants in this proceeding have prepared a joint Procedural History, which will be filed by the Southern Cities ("SOC").

AMENDMENT NO. 60.

The ISO filed Amendment No. 60 with three goals: 1) to provide an identifiably more rational and efficient process for granting or denying waivers of the must offer obligation,[2] 2) to modify certain payment terms and the allocation of must-offer costs in a manner more consistent with cost causation, and 3) to set forth clear conditions in which Condition 2 Reliability Must-Run Units are subject to the must-offer obligation. May 11, 2004 Amendment No. 60 filing ("May 11 Filing") at 1. As noted in the Joint Procedural History, the Commission set the aspect of Amendment No. 60 dealing with the proper allocation of must-offer costs for hearing in this proceeding.

As described in the testimony of Brian Theaker (adopted for this proceeding by 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.
>
> . . .

[2] As noted in the May 11 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 Company, et al*., 95 FERC ¶ 61,115 at 61,354-56 (2001). *See also* Ex. No. ISO-22 at 8.

> The Scheduling Coordinator for a Generating Unit subject to the must-offer obligation also may request a waiver of the must-offer obligation when it wants to shut that Generating Unit off.

Ex. No. ISO-22 at 8-9. Prior to Amendment No. 60, the ISO Tariff did not include criteria by which the ISO would determine whether to grant waivers. Amendment No. 60 added Section 5.11.6.2 of the ISO Tariff, which provides:

> The ISO shall grant waivers so as to: 1) provide sufficient on-line generating capacity to meet operating reserve requirements; and 2) account for other physical operating constraints, including Generating Unit minimum up and down times. The ISO shall grant, deny or revoke waivers using a security-constrained unit commitment ["SCUC"] software application to minimize start-up and Minimum Load Costs.

As Mr. Theaker also described, if the ISO does not grant, *i.e.,* denies, the 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.* These must-offer costs associated with must-offer waiver denials ("MOWD") costs include Start-Up Costs, Emissions Costs, and Minimum Load Costs. Prior to the filing of Amendment No. 60, must-offer costs were allocated to metered Demand within the ISO Control Area, plus exports to other Control Areas within California. May 11 Transmittal Letter at 31.

As described in Ex. No. ISO-20, the ISO undertook a re-examination of its must-offer process in response to Market Participants' concerns and instituted a stakeholder process to enable it to understand the views of Market Participants. Ex. No. ISO-20 at 14-15. As a result of this re-examination, it became apparent that much of the must-offer costs was being incurred to combat reliability problems of something less than a system-wide nature. The ISO, therefore, proposed to change the allocation of these costs through Amendment No. 60. *Id*. at 13. The Amendment No. 60 proposal divides the costs of compensating Generating Units for the Minimum Load Cost compensation ("MLCC") associated with "MOWDs" into three categories: 1) those for costs incurred for Local reliability, 2) those for costs incurred for Zonal reliability, and 3) those for costs 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; 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.

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?

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 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 coming forward with 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 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 the ISO's Testimony 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.

Among the principles the Presiding Judge should consider at this juncture is that of cost causation. There may be arguments in this proceeding that consideration of cost causation does not include consideration of benefits received. The Commission has repeatedly and soundly rejected that argument. 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, *quoting Pacific Gas and Electric Co., et al*., 101 FERC 61,151 at P 23 and n. 39 (2002) (footnotes omitted). The same principles should govern this proceeding.

The history of Minimum Load Cost compensation may also provide guidance in this regard. The provision of compensation to must-offer Generators for their minimum load costs did not arise from an ISO initiative; rather, the Commission directed such compensation in response to concerns from the Generators. *See San Diego Gas & Electric Co. v. Sellers of Ancillary Services, et al.*, 97 FERC ¶ 61,293 at 62,263 (2001). The Commission directed that the costs be recovered in the same manner as Start-Up and Emissions Costs. *Id.* 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.[3] Although Amendment No. 60 attempts to assign MLCC at a more granular level, the fact has not changed that the must-offer requirement provides a reliability function that benefits users of the transmission grid.

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

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

[3] 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 Control Area grid, gross Load in the Control Area and exports from the Control Area to Load in California.

Amendment No. 60. *See* Ex. No. ISO-20 at 14-19. The three buckets rationally reflect reasons that MLCC costs may be incurred and accordingly assign those costs in a manner consistent with cost causation. The ISO currently operates on a three-tier basis. Certain matters are handled strictly within a Zone, such as Intra-Zonal Congestion (*see, inter alia*, ISO Tariff §§ 7.2.6.1 and 7.2.6.2). Others matters involve Inter-Zonal Interfaces, such as Inter-Zonal Congestion (*see, inter alia*, ISO Tariff § 7.2.1.2). A third category is handled purely on a system-wide basis, such as MLCC prior to Amendment No. 60. The three buckets are consistent with this structure.

Local MLCC costs are allocated to the Participating TO in whose Service Territory the Generating Units are located because Participating TOs are in the best position to reduce these costs by upgrading the power delivery network. Ex. No. 22 at 30. They are thus assigned to the entity that "causes" the problem. Similarly, to ensure that costs are allocated to the Demand that gives rise to overloads on paths between Congestion Zones, the ISO's proposal allocates Zonal MLCC costs to Zonal Demand. *Id*. at 33.

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. *Id*. at 28-29. 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.

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?

For the purpose of this section, the ISO will assume that the Presiding Judge will conclude the 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.

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 Ex. No. 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.

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 Ex. No. S-18 at 10. Resolution of these concerns benefits Demand within the Zone and it is therefore appropriate that the costs be categorized as Zonal and charged similarly

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 Ex. No. S-18 at 10. Because all Demand and Exports benefit from resolving such issues, it is appropriate to categorize these types of problems as System problems, although the ISO has proposed a “system-wide” cost allocation that focuses on those most responsible for the problems.

Although these criteria are thus *generally* just and reasonable, the ISO has concluded, after filing Amendment No. 60, that they may not be just and reasonable in two *specific* respects. As noted in the testimony of Brian Theaker (adopted by Jim McIntosh as Exhibit No. ISO-22), the ISO has reexamined its criteria and concluded that there are two cases in which constraints that would fall into the Local category under the criteria proposed in Attachment E should be classified as Zonal costs. The two constraints are the Miguel Substation transformer bank and the South of Lugo transmission path. Ex. No. ISO-22 at 23-24. 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.

A number of parties have advocated other criteria, and might suggest additional criteria or categories. The ISO may address these at hearing or in post-hearing briefs. Except as discussed under other issues below, the ISO has only addressed two of these other proposals in testimony. 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. Ex. No. SWP-1 at 20:1-7. From an operational standpoint, developing criteria for such allocations would be 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. This is described in the testimony of Jim McIntosh, Ex. No. ISO-21 at 16. For these reasons, the ISO does not believe this proposal would be just and reasonable.

Mr. Marcus also recommends that certain Zonal charges be allocated on a subzonal level to specific Loads on a geographic basis. *See, e.g.,* Ex. No. SWP-1 at 8:11-16, 9:8-10, 25:4-6, 38:14 – 39:10. According to ISO testimony, 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. The data points do not correlate with the geographic areas to which Mr. Marcus suggests the costs of what could otherwise be Zonal Minimum Load Cost compensation be allocated. *See* Ex. No. ISO-19 at 21.

Moreover, 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 repeated manual intervention. Accordingly, Mr. Marcus's proposals should be rejected. *Id*.

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

During the stakeholder process that led to the filing of Amendment No. 60, Southern California Edison Company ("SCE") suggested that in cases where the same Generating Unit was committed for both a Local and a System need, only the 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* Ex. No. ISO-20 at 18. The ISO supported this proposal and included it in the Amendment No. 60 filing. *Id*.

The mechanism by which this incremental cost is calculated is for the ISO to operate its SCUC application in two-passes. As described by Brian Theaker in his testimony (as adopted by Jim McIntosh),

> 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.

Ex. No. ISO-20 at 18.

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 positive, 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.

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. Ex. No. ISO-20 at 36.

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.

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,[[4]] particularly the failure of a major transmission line or Generating Unit. A Contingency may occur at any time." Ex. No. ISO-21 at 6. 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.

The ISO has acknowledged that its need to call upon must-offer units historically has arisen in on-peak periods, Ex. No. 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.

[4] 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.

Because non-peak users do receive benefits from MLCC, the failure of Amendment No. 60 to employ time-of-use pricing does not render it unjust or unreasonable.

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 definition of on-peak is most appropriate because it is consistent with the reliability nature of the must-offer requirement. *See* Ex. S-1 at 15.

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. Because Existing Contracts usually provide the Existing Rightsholder with scheduling rights, the Existing Rightsholder is exempt from Usage Charges (congestion charges in the Day-Ahead and Hour-Ahead Markets). Zonal MLCC costs incurred when a unit is committed because of the potential for real-time congestion, however, are not congestion charges. This is explained in the testimony of Catherine Bodine, Ex. No. 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. Because the holders of Existing Contracts benefit from the real-time reliability of the Inter-Zonal Interfaces, it is just and reasonable to include them in the allocation of Zonal MLCC.

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. 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. 97 FERC ¶ 61,293 at 62,263, 62,370. Nothing has occurred or been brought to light to change that determination. There is, therefore, the failure to exempt wheel-throughs does not render 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 to exempt certain pump loads from some MLCC costs. Amendment No. 60, however, does not attempt to examine the specific contribution of specific loads to MLCC costs. To do so would create a very complex system, which would require continual amendment as new constraints arise. For example, the nature of the South of Lugo constraint has changed with transmission enhancement, Ex. No. 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 LSEs 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 Bob Tang, Ex. Nos. 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. Ex. No. ISO-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." Ex. No. SOC-28 at 4.

There are 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. Ex. No. 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*.

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.

Moreover, as explained in the testimony of Catherine Bodine, Ex. No. ISO-19 at 22, "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[5]]." In addition, while 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. *Id*.

For these reasons, the ISO opposes SOC's proposal to institute a program providing for the self-provision of inertia.

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 David Marcus, during the timeframe between July 17, 2004 (the refund effective date for EL04-103) and August 26, 2004,

[5] MRTU is the ISO's Market Redesign and Technology Upgrade, formally known as MD02.

there were several instances of MOWDs being attributed to more than one cause. Ex. No. SWP-18 at 34. These dual categorizations are reflected in the February 18, 2005 version of Ex. No. 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. Ex. No. 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 incurred to 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. Ex. No. 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* Ex. No. 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).

The ISO takes no position on whether this proposal, presented in testimony supported by Powerex, might be just and reasonable. Powerex's arguments against the ISO's proposed allocation for System MLCC costs to Net Negative Uninstructed Deviations ("NNUD"), however, do not withstand scrutiny. Powerex first contends that the allocation would impose duplicate penalties on Generators and Scheduled Interchange, which are subject on Uninstructed Deviation Penalties. Ex. No. PWX-1 at 6. The development, approval, and implementation of penalties for uninstructed Schedule deviations, however, simply has no bearing on this proceeding, which addresses not penalties, but the allocation of costs. If Powerex believes that Generators and Scheduled Interchange are unfairly singled out for Uninstructed Deviation Penalties, its remedy is in proceedings regarding those penalties.

Powerex also argues that the ISO's proposal is inconsistent with cost causation because units are committed based on capacity committed in the Day-Ahead Market to meet projected peak Demand under Operating Procedure M-432C. Ex. Nos. PWX-1 at 7, PWX-3 at 8-10, not based on deviations from Final Schedules. As is apparent from

M-432-C and as Staff witness Patterson properly notes, Ex. No. S-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 between final Schedules and real-time deliveries. Although other allocations may well be reasonable, it cannot be said that allocating the costs according to these real time deviations is unjust or unreasonable. *See* Ex. No. S-18 at 17-18; Ex. No. PGE-5 at 5-6.

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 did 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 proposed 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 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. Ex. No. ISO-20 at 21-22. Nonetheless, should the Presiding Judge determine otherwise, the ISO does not oppose the alternative means of allocating Start-Up Costs advocated by PG&E (Ex. No. PGE-4 at5-6), SWP (Ex. No.

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. Ex. No. ISO-19 at 19.

With regard to the allocation of Emissions Costs, 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. Ex. No. ISO-19 at 20. That being the case, although the allocation alternatives suggested by PG&E, SWP, and the Commission Staff are not complicated (*id*. 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 the refund effective date of July 17, 2004.

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, Ex. No. ISO-19 at 7-8, 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, SCE 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.

TANC has presented testimony criticizing the proposed definition of Reliability Services Costs, both on the grounds that no such definition is necessary (Ex. No. 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. Ex. No. 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 69 (2004) (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," Ex. No. 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 5.11.1 of the ISO Tariff, 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 if its Operating Reserves are depleted by the need to provide Imbalance Energy.

Under 5.11.6 of the ISO Tariff, 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 Western Electric Coordinating Council Minimum Operating Reliability Criteria are the equivalent of the ISO’s Regulation, Spinning Reserves, and Non-Spinning Reserve Ancillary Services. 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, 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 self-providers of Ancillary Services are thus double-billed for Ancillary Services is a red herring. As explained in the testimony of Catherine Bodine, Ex. No. ISO-19, Ancillary Services procured through ISO markets are *capacity* services, whereas Minimum Load Cost compensation is a payment for *Energy*. Ex. No. ISO-19 at 13. 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 will stipulate 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.

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

As noted in the Testimony of Brian Theaker, adopted by Catherine Bodine, Exhibit No. ISO-20, the ISO does not oppose the refund effective date of July 17, 2004. Ex. No. ISO-20 at 40. As described in the testimony of Mr. McIntosh (adopting Mr. Theaker's testimony), however, 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. Ex. No. ISO-22 at 40. Instead, the ISO will 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.

CONCLUSION

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

Respectfully submitted,

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Dated: June 14, 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 14th day of June, 2005.

Stephen A.S. Morrison
Stephen A. S. Morrison