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January 25, 2002

The Honorable Linwood A. Watson, Jr.
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

**Re: California Independent System Operator Corporation
Docket Nos. ER01-313-000, *et al*.**

Dear Secretary Watson:

Enclosed for filing are one original and 14 copies of the California Independent System Operator's Initial Brief in the above captioned proceeding. Two copies of this filing have also been provided to the Presiding Administrative Law Judge. Also enclosed are two extra copies of the filing to be time/date stamped and returned to us by the messenger.

Thank you for your assistance in this matter.

Respectfully submitted,

____
Theodore J. Paradise, Esq.

Counsel for the California Independent System Operator Corporation

CC: The Honorable Bobbie J. McCartney
Service List

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
California Independent System Operator Corporation	)	**Docket Nos. ER01-313-000**
	)	**ER01-313-001**
	)	
Pacific Gas and Electric Corporation	)	**Docket Nos. ER01-424-000**
	)	**ER01-424-001**
	)	

INITIAL BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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Dated January 25, 2002

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all parties on the official service list compiled by the Secretary in the above-captioned proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, DC this 25th Day of January, 2002.

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INITIAL BRIEF OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

To: The Honorable Bobbie J. McCartney

The California Independent System Operator Corporation ("ISO") hereby submits its Initial Brief in this proceeding.

I. PROCEDURAL HISTORY

Please see the Parties' Joint Procedural History .

II. INTRODUCTION AND SUMMARY

It is important initially to place this proceeding in context. As in all rate cases, two issues predominate: revenue requirements and rate design. As is typical, the filings have been voluminous and the hearing protracted. That, however, is where the similarities end; the ISO is not a typical regulated entity and the process that the ISO initiated long before the initial filing in this proceeding provided an unprecedented level of third-party input and scrutiny of both revenue requirements and rate design.

The process began as early as 34 months before the initial filing – with an intensive *and public* examination first of unbundling and then of budgeting, Exh. ISO-1 at 8:22 – 9:1, each with extensive stakeholder scrutiny. It culminated with approval by the Finance Committee and then by the full *stakeholder* Board.[1] Exh. ISO-16 at 7:2-8; ISO-20. Before both bodies, management's budget presentations set out in detail anticipated expenditures, both operating and capital, on a departmental basis, *see, e.g.,* Exh. ISO-19, and the public was free to comment on either revenue requirements or rate design. Exh. ISO-16 at 5:5-29, 7:6-7. Of course, this detailed stakeholder process does not replace Commission scrutiny; it should, however, inform the Presiding Judge's analysis. If the stakeholder process is to accomplish its goal and its use is to be encouraged, the results must be accorded a measure of deference.

That is particularly so here, where the hearing process, though lengthy and at times contentious, has failed to raise any serious challenge to either the revenue requirement or the rate design that emerged from the stakeholder-driven process. There are allegations that "costs are too high," but no one has contended that any capital expenditure is inappropriate, that the ISO is pursuing unnecessary activities, or that any function can be curtailed. Exh. ISO-21 at 19:16-20; Tr. 201:17-24.

California's electricity markets have been in crisis. This reality must inform review of the ISO's revenue request. The largest investor-owned utility ("IOU") is bankrupt and the PX itself is both in bankruptcy and defunct. These events, and the demise of the predominant forward markets, added enormous burdens to an already

[1] Comprising representatives, among others, of public power, investor-owned utilities, independent

pressed ISO staff as it struggled to keep the lights on. Exh. ISO-21 at 6:15-18. Essential tasks had to be deferred, including, most prominently, the Congestion Management Redesign that remains high on the agendas of both the Commission and the ISO. *See San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services, et al.*, 93 FERC ¶ 61,121 at 61,366 (2000) ("market redesign is crucial").

Normalcy is beginning to return and, with it, the ability of the ISO to begin the difficult job of market redesign that remains so essential to the achievement of true competition. Now is precisely the wrong time to constrain the ability of the ISO to move forward.

For example, one party noted the fact that the ISO will not be incurring anticipated interest expense on new debt, *see, e.g.,* Exh. TNC-1 at 12:15-22, because events have precluded access to capital markets. Exh. ISO-21 at 24:7-8. Yet that simply means that it will be more costly for the ISO to meet its responsibilities. The needed investments now will have to be supported by operating revenues to the extent they are available. *Id*. at 24:4-10, 25:11-15.

As to rate design, some have suggested very different methods of unbundling the GMC. *See, e.g.*, Exh. MID-1 at 5:15-18. "Unbundling" remains very much a work in progress, and the ISO remains committed to work with all in the stakeholder process to carry that evolution forward. Exh. ISO-21 at 51:5-8, 62:17-19. For now, no one has suggested that the steps proposed by the ISO are inappropriate, or that doing more at this time is even feasible.

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generators and marketers, and end-use consumers. *See generally* Exh. ISO-1 at 10:5-6.

Although one rate design issue, "gross vs. net," has been dealt with exhaustively, there has been no serious rebuttal to the unified position of the ISO and Commission staff: only the "gross" methodology avoids a cost-shift to those who already pay for the costs that they impose. *See* Issues I.E and I.F, *infra*.

Finally, the ISO is not opposed to a modified formula rate approach (*e.g.*, a filing "trigger") if it is structured to accommodate the range of cost uncertainty that is inevitable. *See* Issue I.M, *infra*.

III. DISCUSSION OF ISSUES

Issue I.A: Is the ISO's Proposed Revenue Requirement for the 2001 Grid Management Charge Just and Reasonable?

In evaluating the ISO's proposed revenue requirement, it is important to recognize both (1) the status of the ISO as a non-profit public benefit corporation and (2) the nature of rate case operating cost and capital expenditure projections.

The ISO's status is important in several respects. First, the ISO has limited discretion as to the timing and level of expenditures. *See*, *e.g.*, Exh. ISO-21 at 6:15 - 8:1. Both are a product of its responsibilities as the Control Area operator of one of the largest transmission grids in the nation. The ISO must meet the reliability requirements of the Western Systems Coordinating Council ("WSCC") and the National Energy Reliability Counsel ("NERC"), and the obligations imposed by the Commission. It must keep Generation and Demand balanced and electric service stable whatever the eventuality and however unforeseeable. Exh. ISO-10 at 4:11 - 14:7. Second, the ISO has but one source of revenues - its GMC. Tr. 218:13-14. If those revenues are deficient, there is no shareholder equity to dip into or, currently, access to capital markets. Exh. ISO-21 at 24:7-8. If the dollars are not there, responsibilities must be sacrificed notwithstanding the implications to the market and ultimately to consumers. Third, from the outset, ISO management has taken concrete steps to encourage the efficient discharge of ISO responsibilities. Exh. ISO-21 at 8:2-5, 9:6-10. Cost containment is a consideration in the application of the incentive compensation system to *every* ISO employee. Tr. 207:24 - 208:23. The ISO is atypical in another respect: in the event of revenue over-collections, consumers, not shareholders, are the ultimate beneficiaries. ISO Tariff (Exh. J-2) § 8.5; Exh. ISO-7 at 33:12 - 37:5.

Cost projections necessarily involve judgments. For a traditional utility, recent past experience typically is the best barometer of future expenses – hence, the logic of the Period I and II submissions. For the ISO, where no one historic period over its short operating life has been a faithful approximation of periods that followed, the past is at best a rough guide. In these circumstances, the rules that have always guided evaluation of rate case submissions are particularly apt: were the cost estimates reasonable *when made;*[2] did the proponent follow a process designed to produce *reasonable* projections?[3] Of that, here there can be no serious doubt. *See* Exh. ISO-7 at 20:22 - 24:7; ISO-16 at 5:5 - 9:23; Tr. 211:22 - 212:9.

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[2] *See Papago Tribal Util. Auth. v. FERC*, 773 F.2d 1056, 1059-1060 (9th Cir. 1985). (FERC need not adjust test year estimates to reflect actual data; standard is whether estimates reasonable when made).

[3] *See New England Power Co.*, 31 FERC ¶ 61,047 (1985), *reh'g denied*, 32 FERC ¶ 61,112 (1985) ("the appropriate test is whether they are costs that a reasonable utility management would have made, in good faith, under the same circumstances and at the relevant point in time"), *aff'd sub nom Violet v. FERC*, 800 F.2d 280 (1st Cir. 1986); *see also Southern California Edison*, 97 FERC ¶ 61,148 at fn. 10 (2001). A utility's good faith

The construction the 2001 revenue requirement began in June 2000 with the development of departmental operating budgets and proposed projects for the capital budget. Exh. ISO-7 at 21:4-22. Following several iterations, a proposed budget was presented to the Finance Committee of the Board with a range of alternatives assuming varied levels of activity. Exh. ISO-16 at 6:1-13. With Finance Committee guidance, the ISO posted a proposed budget on the ISO home page, and conducted a public workshop. *Id*. at 6:16-21. In late October, management presented stakeholder comments and its budget recommendations to the full Board. *Id.* at 6:21 - 7:1. Following public comment, the Board directed ISO management to consider a range of cost reduction options. *Id.* at 7:1-2. Management presented those options to the Finance Committee in a public session. *Id.* at 7:2-4. Ultimately, following yet another opportunity for public input and with the benefit of departmental budgets identifying anticipated expenditure changes between the years 2000 and 2001, *see*, *e.g.*, Exh. ISO-19 at 4, the Finance Committee decided against sacrificing the ability of the ISO to meet anticipated activity levels. Exh. ISO-16 at 7:4-6; ISO-21 at 22:4-15. The Board accepted the Finance Committee recommendation and that budget became the core of the ISO's rate request for 2001. Exh. ISO-21 at 22:15-16. Significantly, no one has challenged either the appropriateness or the thoroughness of the budgeting process. *Id.* at 5:11-13.

The revenue requirement projected for 2001 does represent a significant increase over 2000 levels, $225 vs. $178 million. Exh. ISO-16 at 7:13-14. It reflects

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is *presumed*. *See New England Power Co. 31 FERC at 61,082, citing West Ohio Gas Co. v. Pub. Util. Comm'n* the reality that the ISO's responsibilities have increased markedly.

Exh. ISO-21 at 6:1 - 7:30; ISO-22. The stakeholder Board, comprising representatives of entities that pay the GMC, no doubt would very much have wished a lower revenue requirement to be possible, but its affirmative vote signifies that, in the end, the Board felt obliged to go forward with the minimum request it considered reasonable in light of the ISO's responsibilities. ISO management has benchmarked its costs against peers, focused in detail on actual tasks performed, renegotiated vendor contracts,[4] and converted consultants to employee status where that is more cost-effective. Exh. ISO-21 at 8:2-5, 9:6-10. Significantly, no intervenor has recommended that the ISO cut any planned activities. *Id.* at 19:18-20.

The capital budget, a critical component of the expenditures of a technology-driven enterprise, was also subjected to rigorous review – both internal and public. Exh. ISO-7 at 21:19 - 23:17. Wherever the ISO could pare projects without prejudicing system reliability or market operations, it did so. *Id.* at 22:11-12. Only capital projects that survived a rigorous screening were included in the budget, and thereafter, capital projects are subjected to a detailed approval process including a cost-benefit analysis before proceeding. Tr. 485:21-24.

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of Ohio, 294 U.S. 63, 72 (1935).

[4] Not surprisingly, because the ISO is a technology-dependent entity, vendor costs account for a significant portion of the its revenue requirement. One vendor contract, as to which the ISO has virtually no discretion, predominates in that category of costs – the contract with MCI that the ISO's predecessor, the ISO Restructuring Trust, negotiated and executed in 1997. At that time, there was pressure to get the ISO operational as quickly as was possible, and to provide a technology platform that readily could accommodate expansion of the ISO, however that growth might develop. There were few, if any, alternatives to be had, and MCI was selected. Exh. ISO-21 at 46:17-21. Over the years, the ISO has sought to renegotiate the contract, but the net charges remain substantial -- $33.4 million per year – and beyond the discretion of the ISO at least until the expiration of the contract in 2003. *Id*. at 46:23 – 47:2.

Criticisms have been directed at two aspects of projected personnel costs: the assumed personnel level, Exh. TNC-1 at 8:1-5, and the employee incentive compensation system, Exh. SMD-1 at 10:12-15. As to the former, the 544 employees projected for 2001 would have proven inadequate even if that level could have been met. Although the unanticipated tasks that the ISO was called upon to discharge required even more personnel, Exh. ISO-21 at 20:17-19, the turmoil in California precluded reaching even the budgeted staffing level, requiring reliance on *more costly* contract employees and consultant resources. *Id*. at 20:10-11.

Criticisms of the employee incentive system could not be more misplaced at this crucial time. The incentive program was implemented to enhance efficiency. Tr. 207:24 - 208:23. Its elimination would be counterproductive. It is a key element of total staff compensation, part of the bargain made with employees to induce them to sign on and to remain notwithstanding exceedingly demanding working conditions. Exh. ISO-21 at 27:8-10. Its curtailment would be highly detrimental to morale and further complicate the ISO's difficult task of attracting and retaining personnel in the atmosphere of uncertainty that exists in California. *Id.* at 26:23 – 27:17. Neither would it be appropriate to reduce the revenue requirement because the ISO budget assumes a 100% payout of employee bonuses in 2001, instead of the 73% projection previously used. Tr. 260:2-14. The very object of an incentive compensation program is to encourage behavior requiring full payment. If the ISO ultimately pays less than 100% any savings will flow to the operating reserve, reducing the revenue requirement in future years.

In the final analysis, the ISO has fully supported its revenue requirement. It filed not only Period I and II cost statements, but also an analytical support document, including a Cost Allocation Matrix ("CAM"), Exh. ISO-18. The document sets forth the activities and budgeted costs (totaling net operating expenses of $169,396,000) of each of the ISO's cost centers, *id*. at 6, 37, 44-45, and the ISO's total debt service cost ($63,141,000), *id*. at 40-44. These costs, less the applicable prior year revenue credit ($7,230,000), constitute the ISO's 2001 revenue requirement of $225,307,000. *Id*. at 3.

Sub-Issue I.A.1 Should Forecasted O&M Expenses Be Reduced by Amounts Discussed in ISO Management's November 9, 2000 Memorandum?

Arguments to reduce O&M expenses to reflect potential cost reductions identified in an ISO management memorandum, *see, e.g.*, Exh. TNC-1 at 10:11 – 12:10; SMD-3 at 6:25 - 7:7, misconstrue the nature of that management exercise – to enable the ISO Board to review costs that the ISO management was less than absolutely certain would be incurred. *See* Exh. ISO-21 at 21:23 - 22:3. The Finance Committee considered the memorandum, but concluded that the reductions were inadvisable in light, in particular, of "the uncertainty of the market in California this year, and the inherent difficulty of predicting what costs will be incurred in such an environment." *Id*. at 22:4-7. There is no evidentiary basis for questioning the prudence of this judgment. Indeed, the Board was prescient. Many of the costs identified in the memorandum have been incurred and, while others have been incurred at a lower level, related activities have imposed additional costs. *Id.* at 22:17 - 23:19. In fact, the ISO has experienced substantial costs that were not foreseen at all.[5] Further, billing determinant volumes were well below anticipated levels. *Id*.

Sub-Issue I.A.2: Should Forecasted Costs Associated With the New ISO Debt the ISO Assumed It Would Issue in 2001 Be Eliminated?

Prior to 2001, the ISO financed capital expenditures through the issuance of debt. Exh. ISO-7 at 11:14-17; ISO-21 at 23:22- 24:3. In its 2001 revenue requirement, the ISO included the carrying cost on that previously-issued debt plus $10.62 million to service new issuances (with the required collection related to the operating reserve). Although a reduction in the ISO's credit rating precluded the issuance of bonds during 2001, Exh. ISO-21 at 24:7-8, the end result was to *increase* costs because it became necessary to finance capital expenditures on a "pay as you go" basis. *Id.* at 24:4-7.

Denied a line of credit, *id*. at 15:11-16, the ISO in 2001 had to use its operating reserve both to meet unanticipated expense levels and to cushion revenue shortfalls. *Id*. at 25:11 - 26:19. Although capital investment has decreased, to $23 million from the budgeted amount of $37.7 million, the need to fund capital projects directly from rates will cause the ISO to exceed the 2001 GMC revenue requirement ($10.62 million) budgeted for this purpose. *Id*. at 25:9-11. Making up the remainder will require $12 million of the operating reserve. *Id*. at 26:16-19. Thus, eliminating the budgeted amount for new debt is not practical given the events of 2001.

[5] For example, legal costs are anticipated to exceed the budget by $1 million or more, interest costs by $4 million, and debt service principal costs by $2 million. Exh. ISO-21 at 23:12-17.

Issue I.B: Is the ISO's Unbundling of the GMC Into the Three Proposed Service Categories Just and Reasonable?

For a rate design to be acceptable, it need be neither perfect nor even the most "desirable"; it need only be reasonable.[6] It is understandable that, viewed from their individual vantage points, intervenors would question whether this rate design is the most "desirable." Nonetheless, the GMC charge is being unbundled into three cost components reflective of three distinct service categories. This is a giant first step in an evolving process – grounded in a solid, analytic process, producing results that are eminently fair and a marked improvement over the past. The very absence of serious criticism speaks eloquently to the design's reasonableness. It should be accepted as filed.

Following the 1998 GMC settlement, a stakeholder steering committee was formed. Exh. ISO-1 at 5:9-14. It had the benefit of input from stakeholders and ISO staff, as well as of the varied views among committee members. *Id.* at 10:9-16; ISO-2(1)-(33). The committee offered a forum for the full consideration of each proposal. Debate was extensive. Exh. ISO-1 at 10:13-15. Market Participants and ISO management were kept apprised of the ongoing effort. *Id*. at 10:19 - 11:10.

A consultant chosen by the stakeholder steering committee initially identified two potential cost categories: (1) Control Area Operations and (2) Market Operations. *Id.* at 17:5-19. The committee further divided the two categories into five. *Id.* Upon

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6 *See New England Power Company*, 52 FERC ¶ 61,090 at 61,336 (1990), *reh'g denied*, 54 FERC ¶ 61,055, *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. 1984), *cert. denied*, 469 U.S. 917 (1984) (utility need 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.

further analysis, the ISO settled on three – Control Area Services ("CAS"), Market Operations ("MO"), and Inter-Zonal Scheduling[7] – based on several considerations: (1) better alignment of cost responsibility with cost incurrence, *id.* at 16:5-7; Exh. ISO-21 at 29:20-23; (2) minimization of complexity to avoid unnecessarily burdening Scheduling Coordinators ("SCs") and discouraging the participation of smaller entities, Exh. ISO-1 at 16: 22 - 17:3; ISO-21 at 29:20 – 30:1; (3) compatibility with the capability of accounting systems in place among stakeholders, Exh. ISO-21 at 30:2-4; and (4) creation of categories that each represent at least 5% of the ISO's costs, Exh. ISO-1 at 17:1-2. The Joint Audit/Finance Committee and the full Board approved the three service categories. *Id.* at 11:6-10.

Unbundling the GMC is a work in progress; the ISO remains committed to working with stakeholders to refine it. Exh. ISO-21 at 62:17-22. The current proposal, however, is a significant beginning and a reasonable design.

Sub-Issue I.B.1: Should the ISO's Proposed Service Categories for Recovering the GMC be Supplemented or Replaced by Other Methodologies or Service Categories?

The proposals advanced by intervenors, while deserving of consideration in a stakeholder process, are not now appropriate candidates for adoption – particularly as it cannot seriously be contended that the disaggregation proposed by the ISO is either unjust or unreasonable.

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.").

1. Dr. Kirsch / MID Proposal

While his testimony is cast primarily in terms of billing determinants, Dr. Lawrence Kirsch recommends, in effect, that the CAS charge be separated into four categories. Exh. MID-1 at 5:15-18. Dr. Kirsch's proposal should be rejected. First, Dr. Kirsch has not established that charging for CAS based on Control Area Gross Load is unreasonable; to the contrary, he acknowledged that "all load gets *some* benefit from the ISO's services," Exh. MID-4 at 3:5-6, 5:19-21, and that the ISO's costs are at least "indirectly" related to the amount of Load. Tr. 1674:4-6, 1716:15-17. Dr. Kirsch simply believes that his proposal would be "more efficient and equitable." Exh. MID-1 at 3:11. Dr. Kirsch's proposal is inappropriate, however, because CAS involve more than resolving Energy imbalances and managing transmission flows. Exh. ISO-29 at 20:1-17; S-1 at 16:21 - 18:7. Second, Dr. Kirsch's proposal had not undergone stakeholder review. Exh. ISO-21 at 55:12-14; Tr. 1676:20-22. Reasonable, extensively analyzed proposals should not be jettisoned for a new proposal that is far from fully developed, *see*, *e.g.* Tr. 1665:17 - 1666:6, 1676:12-16, and thus of uncertain merit. Third, the ISO set up its software, including that for billing and settlements, to accommodate a single CAS charge, and understands that parties paying the GMC did the same. Exh. ISO-21 at 55:19-23. The software cannot do the tracking required by Dr. Kirsch's proposal, *id.* at 55:23 - 56:2, and the necessary changes would be costly and time-consuming. *See* Exh. S-14.

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[7] The steering committee's categories "Scheduling" and "Control Area Operations" were combined into CAS and its categories "Billing and Settlements" into MO. The remaining committee category, "Congestion Management," was renamed "Inter-Zonal Scheduling." Exh. ISO-1 at 17:10-11, 18:12-13.

In sum, Dr. Kirsch's recommendation is a last-minute, partially formed, un-vetted proposal that would disrupt the orderly implementation of the unbundled GMC. Tr. 1676:23-24. Staff correctly concludes that it should be rejected without prejudice and considered in a 2003 stakeholder process. Exh. S-6 at 35:1-8; ISO-21 at 57:16-19.

2. <u>CPUC Proposal</u>

Mr. Ramirez suggests that behind-the-meter Load pay a lesser CAS charge, implying a further subdivision of that cost category. Exh. PUC-1 at 14:19 - 15:2. The ISO is willing to consider that suggestion as part of a stakeholder process in 2003. As explained below, the ISO's current proposal is just and reasonable.

Sub-Issue I.B.2: If Changes to the Service Categories are Ordered, Should the Changes be Effective Prospectively (*i.e.* From the Effective Date of the Decision), or Retroactively (*i.e.* From the Date of ISO Implementation)?

If the Presiding Judge concludes it is appropriate to modify any of the results of the lengthy stakeholder unbundling process, those modifications should be implemented prospectively. *See* Exh. ISO-21 at 53:5-6. It is common for rate design changes to be implemented prospectively;[8] in the case of the non-profit ISO, it is essential. Retrospective application would leave the ISO vulnerable to under-recovery. Unless the ISO could implement corresponding surcharges, its financial viability would be at risk. There are also practical impediments to retroactive application at this time. The ISO does not currently have the data necessary to allocate

[8] The Commission's policy that changes to the design of rates should be made prospectively recognizes that a utility would under-collect its actual costs if required to make refunds to parties without an ability to

2001 costs to more than the proposed categories; its billing and accounting systems are not configured to administer more categories, Exh. ISO-21 at 60:5-15; and the rates now in place use billing determinant volumes for the three-category structure. *Id.* at 60:7-10. If retroactive charges are ordered, however, the ISO's request for surcharge authority should be granted. *See* 2001 GMC November 1, 2000 Transmittal Letter at 11.

Issue I.C: Is the ISO's Proposed GMC Allocation Just and Reasonable?

The ultimate allocation of the GMC involves a three-step process: (1) adoption of logical service categories; (2) the allocation of costs among those categories; and (3) the assignment of responsibility based on billing determinants. The service categories are addressed *supra*. The discussion below concerns the division of costs among those categories and the billing determinants.

1. Allocation of Costs to Service Categories is Just and Reasonable

The GMC comprises two types of costs: (1) general operating and maintenance costs; and (2) debt service costs. Exh. ISO-7 at 9:13-14. ISO managers and directors, guided by task-specific allocation aids developed by Mr. Leiber's project team, assigned budgeted costs to the service categories. *Id.* at 14:19-23. Allocating costs necessitates judgments. Exh. ISO-21 at 37:15-21. Indeed, the informed experience of supervisors is critical input. *Id.* at 37:5-10. The task is to provide those called upon to exercise judgment with tools designed to further uniformity of approach and a reasoned overall result.

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charge others more than they had paid under the original rate design. *Second Taxing District of the City of*

While operational costs were directly assigned when possible, "overhead" costs were generally assigned using other allocation approaches, such as proportionally based on the results of the direct assignment. Exh. ISO-7 at 14:5-11. Costs related to the telecommunications system and to particular computer applications were allocated based on ISO headcount. *Id.* at13:13-21. Capital costs were assigned based on use of the funds. *Id.* at 15:9 - 16:21.

The ISO's initial submission included a CAM, Exh. ISO-9, that provides additional allocation details for operating and capital costs, and for applying those allocations to 1999 actual expenditures. Exh. ISO-7 at 18:4-6. In a supplemental submission, the ISO provided further and updated allocation details applied to 2001 data, Exh. ISO-16 at 3:21 – 4:8, 4:21 – 5:2, 10:3-13:23, a revised and updated analytical support document, and a CAM for 2001. Exh. ISO-18. The analytical support document details all 57 ISO cost centers, including the tasks and responsibility of each, and the specific allocation methodology used. *Id.* The CAM provides specific dollar figures and percentages for each cost center attributable to each service category. Exh. ISO-18; ISO-21 at 36:2-5.

Although some parties favor a greater level of granularity and advocate complicated cost-tracking systems, such as time slips, *see, e.g.*, SMD-1 at 11:15-23, the ISO's proposal represents a major step in the direction advanced by those intervenors.[9] Consideration of more complex record-keeping may be appropriate for the

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Norwalk v. FERC, 683 F.2d 477 at 490 (D.C. Cir. 1982); *Commonwealth Edison Co.*, 8 FERC ¶ 61,277 (1979).

[9] One intervenor advocates use of a detailed labor analysis instead of headcount. Exh. TNC-1 at 14:16-23. The ISO's analysis, provided to that intervenor in response to a data request, shows that the two methods

future. *Id*. at 58:17-22. Indeed, the ISO has refined its 2002 budgetary process to incorporate a much more rigorous process of direct assignment of costs to the three service categories. *Id.* at 58:5-15. Adding levels of detail before they are fully vetted, however, would be counterproductive, *id. at* 39:11 – 41:18, particularly as they might stifle the *esprit de corps* that has served the ISO and its constituency so well. *Id.* at 41:20 - 43:2. Additional detail should be adopted only if it can be accommodated and if the cost of doing so is justified. At this point, and on this record, that showing has been made only for the level of granularity incorporated in the ISO's filing.[10]

2. The ISO's Billing Determinants Are Just and Reasonable

Prior to unbundling, the GMC was allocated on the basis of usage of the ISO Controlled Grid in MWh. Exh. ISO-1 at 21:6-7. The stakeholder steering committee proposed several alternative determinants for each service category. *Id.* at 21:14-15. ISO management selected two for each of the categories for further extensive review with the committee. *Id*. at 21:15-17. In making a final selection for each category, the committee and the ISO agreed that the objectives were to allocate costs so as to best reflect cost causation, to maximize price certainty, to minimize adverse impacts on market behavior, to avoid the creation of barriers to market entry, and to be logistically practical. *Id*. at 21:20-23.

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produce essentially the same results for 2001. Exh. ISO-21 at 44:23 – 45:2; Tr. 280:5-10. Both the ISO and the California Public Utilities Commission believe that headcount is an appropriate methodology. Exh. ISO-21 at 43:8-14, 44:12-23; PUC-1 at 10:1-16. Nonetheless, the ISO has accepted the suggested change and used a labor analysis in allocating the 2002 GMC. Tr. 279:12-16.

[10] It should be noted that generalized criticisms of the ISO's allocations appear based on misunderstandings. Exh. ISO-21 at 45:6 – 46:9.

Those objectives have been achieved. The billing determinants selected for the allocation of costs of both Inter-Zonal Scheduling and MO have been noncontroversial. The billing determinant for CAS is shown to be just and reasonable under Issues I.E. and I.F. below.

Sub-Issue I.C.1: Does the ISO's Cost Allocation Matrix Provide a Reasonable Basis for Allocating Costs?

The ISO's basis for allocating costs, and the reasonableness of that allocation, is described above. The analytical support document and CAM, Exh. ISO-9, updated for 2001 by Exh. ISO-18, while providing significant detail, *see* Exh. ISO-21 at 35:19 – 16:18, explains the ISO's allocations. It is supplemented by Mr. Leiber's testimony. *See* Exh. ISO-7 at 4:12 - 20:17; ISO-16 at 10:3 - 10; ISO-21 at 31:15 - 33:18. This evidence fully sets forth the ISO's rationale for assigning costs.

Sub-Issue I.C.2: Is the ISO's Allocation of Cost Center 1424 Just and Reasonable?

Direct assignment of Cost Center 1424, "Information Technology Assets, Contracts and Change Management," to service categories based on the judgment of the cost center manager/director, Exh. ISO-18 at 60; S-10, was entirely appropriate. The costs at issue support the operations of the entire ISO, necessitating the exercise of judgment in their assignment. *See generally,* Exh. ISO-21 at 37:15-21.

Whenever judgment must be exercised, especially for the first time in a particular area, it can be expected that improvements might be identified. In preparing a response to a data request regarding Cost Center 1424, the ISO found that the allocation process could be improved by a detailed assignment of these costs to individual

ISO projects or service categories. *Id.* at 49:21 - 50:20. The ISO has done so for 2002. *Id.* at 50:7.[11]

Nonetheless, that improvements may be implemented in subsequent years provides no justification for rejecting the current proposal. Such a policy would discourage applicants from making suggested improvements. Moreover, the possibility of future refinements does not render the current proposal unjust or unreasonable.[12]

Sub-Issue I.C.3: Is the ISO's Allocation of MCI Contract Costs Just and Reasonable?

Allocation of MCI contract costs (the bulk of Cost Center 1441) presented a unique challenge and required the exercise of judgment by those knowledgeable about the capabilities of the ISO's telecommunications infrastructure and its use. *Id.* at 37:15-21, 48:7-18. Its use is pervasive across *all* cost centers, but not to the same level of intensity. *Id.* at 48:7 - 49:8.

Although the robust telecommunications infrastructure provided by the MCI contract was to some extent designed to facilitate electricity markets, it also enables the ISO to perform tasks that span all of the service categories.[13] *Id*. Based on the judgment of experienced hands-on operators, a modified headcount method was developed. A portion of the costs was allocated based on total ISO headcount, a

11 Indeed, the ISO stated its intention wherever possible to make greater use of a detailed assignment of costs in its 2002 GMC filing. Exh. ISO-21 at 50:17-20, 58:7-15. As such, the ISO will address the concerns raised by Mr. Cohen of TANC with respect to the allocation of 1424 costs. Exh. TNC-1 at 17:14 - 18:7.

12 Even if the refinements were incorporated in 2001, they would decrease the CAS charge by only 1.6%, and increase the MO charge by a like percentage. Exh. ISO-21 at 51:9-16. This minimal shift would be more than offset if other potential adjustments identified in 2001 were applied as well, *id.* at 51:19-22; this underscores the inappropriateness of piecemeal changes to allocation procedures, *id.* at 51:1 - 52:2.

13 For example, it is the essential platform between the ISO and Generating Units that are on Automatic Generation Control ("AGC"). Exh. ISO-21 at 48:9-16.

portion was allocated based on a headcount of only those departments that use the network significantly, and a portion was assigned directly to MO to account for that service category's near exclusive use of certain aspects of the ISO's telecommunication services. *Id*. at 47:11-16. The overriding objective was an assignment that reflected cost causation.[14] The allocation is just and reasonable.

Sub-Issue I.C.4: If Changes to Allocations are Ordered, Should the Changes be Effective Prospectively or Retrospectively?

For the reasons of policy and practicality already discussed – to avoid applicant hostility to allocation and cost assignment refinements and to protect the financial viability of the ISO – any changes deemed appropriate should be incorporated prospectively only. *See* Exh. ISO-21 at 50:22 - 52:21.

Issue I.D: Should the ISO Assess GMC Undercollections to Other Creditworthy GMC Customers?

Section 8.4 of the ISO Tariff provides for two types of adjustments. Annual adjustments can address, among other things, a variance between forecast and actual revenue attributable to the inability to recover from an SC. ISO Tariff (Exh. J-2) § 8.4. Tariff authority to recover such shortfalls is critical for a nonprofit entity such as the ISO.[15] The Commission has indicated that the use of a "charge-back" mechanism may not be appropriate in the circumstance of a major financial catastrophe, when its

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[14] While the ISO believes that this method of allocation is appropriate given the unusual nature of the cost center, *i.e.*, that it is used by all segments of the ISO but not precisely at the same level, Exh. ISO-21 at 47:11-19, it is not averse to a more precise allocation approach. The dilemma is that, to date, the ISO has been unable to obtain from MCI the data necessary for a more fine-tuned direct assignment. *Id*. at 49:10-15.

[15] The ISO has various other mechanisms to recover revenue shortfalls before making the annual adjustment under ISO Tariff § 8.4. *See* ISO Tariff (Exh. J-2) § 11.12 (enforce letters of credit guarantees); § 11.20.1 (bring legal proceedings against SCs who fail to pay); SABP § 6.3.1.3 (collect GMC shortfall from market obligations).

use would threaten the financial viability of other Market Participants. *Pacific Gas & Electric Co.*, 95 FERC ¶ 61,020 (2001). It is highly unlikely that any adjustment in the GMC based on a revenue shortfall would approach such a level. *See* Exh. ISO-21 at 67:9-13; fn. 15, *supra.* As discussed *infra*, however, the ISO does not oppose requiring Section 205 filings for increases in the revenue requirement in excess of reasonable "triggers." Because any major "charge-back" would thus require a Section 205 filing, any concerns about the adjustment to the revenue requirement could be addressed by the Commission.

The other adjustment, made in accordance with Part B of Schedule 1 of the ISO Tariff, allows the ISO to modify on a quarterly basis, without a Section 205 filing, only the projected volumes for GMC service categories (*i.e.*, the billing determinants) when the projected volumes are off by 5 percent or more. ISO Tariff (Exh. J-2) at Schedule 1, Part B. Such adjustments could not be used to compensate for the ISO's inability to recover from an SC, which inability does not affect volumes. Accordingly, the Presiding Judge should find that, with the Section 205 filing requirements described above, adjusting the revenue requirement to recover costs attributable to SC default is just and reasonable.

Issue I.E: Is the Assessment of the Control Area Services Charge Based on Control Area Gross Load Just and Reasonable and Not Unduly Discriminatory as to Load Not Served by On-Site Generation?

Mr. Deane Lyon describes in detail the CAS that the ISO provides on behalf of all Load within the ISO Control Area. Exh. ISO-10 at 18:15 - 29:4, ISO-29 at 12:11 -

20:19. These are the services essential to ensure the safe and reliable operation of the transmission system within the Control Area.[16]

No party seriously questions the ISO's provision of CAS, the necessity that it does so, or the reliability benefits that ensue therefrom. Some parties assert, however, that behind-the-meter[17] Loads benefit from these services only during such times as they are served by Energy transmitted through the ISO Controlled Grid, [18] *See, e.g.*, Tr. 1710:19 - 1711:17; 2763:19-25, and therefore should not be charged for CAS, or should be charged a lesser amount, when they are not using power transmitted over the ISO Controlled Grid.

In evaluating these arguments, it is important to keep in mind that the ISO is not seeking to charge behind-the-meter Load served by behind-the-meter Generation for the *use* of the ISO Controlled Grid. Such Loads do not have to be scheduled as if they used the ISO Controlled Grid and they are not assessed the transmission Access

[16] Among the included functions are the necessary analyses of system security; the establishment of transmission maintenance standards; system planning to ensure overall reliability; integration with other Control Areas; emergency management; outage coordination; the scheduling of Generation, imports, exports, and Wheeling in the Day-Ahead and Hour-Ahead of actual operations and after-the-fact reconciliation activities; annual and multi-year studies to determine the need for Reliability Must-Run generator contracts; operational studies, real time monitoring and dispatching; and the dispatch and monitoring of Ancillary Services. *See* Exh. ISO-29 at 14:4-24, 31:6-9.

[17] "Behind-the-meter" in this context may refer to circumstances in which retail Loads of an entity and the Generation from which that entity serves the Loads are located on the same side of the meter at the inter-connection between the ISO Controlled Grid and the transmission or distribution facilities of the entity. Tr. 1145:24 - 1147:12. Parties have denominated these circumstances as "wholesale behind-the-meter." *Id.* It may also refer to circumstances in which a Load is served by a Generator located on the side of the retail meter between the Load and the ISO Controlled Grid or between the Load and the distribution system of a UDC. Parties have denominated these circumstances as "retail behind-the-meter." To the extent that retail behind-the-meter Loads present circumstances different from wholesale behind-the-meter Loads, they are discussed in the next section.

[18] Transmission on the ISO Controlled Grid and "use" of the grid is employed here in the sense of a contract path. The ISO uses the term contract path to describe the transfer of Energy from Generator A to Load B when Generator A has agreed to sell or otherwise provide Energy to Load B, Generator A indeed generates the agreed upon amount of Energy, and Load B actually consumes that amount. The ISO recognizes that

Charges. Tr. 2743:9-12; 2743:23 - 2744:1. The charges at issue are solely the ISO's costs for CAS, which ensure the reliability of service to those Loads.

Contrary to these arguments, behind-the-meter Loads, by virtue of interconnection with the ISO Controlled Grid, benefit from the ISO's CAS at all times. *See* Exh. ISO-10 at 15:1 – 18:9. For example, if a Generator serving Load behind-the-meter fails, the ISO's area control error ("ACE") immediately changes by the amount of the lost Generation (plus the changes in system losses). *Id.* at 16-18; Exh. ISO-29 at 15:11-15. Generators providing Regulation to the ISO and on AGC are issued control signals to adjust their output for the deficiency. Exh. ISO-10 at 15:18-21; ISO-29 at 15:11-15. To return the Regulation units to their preferred operating points, the ISO then calls on resources from the real time balancing Energy market. Exh. ISO-10 at 15:21-23; *see also* ISO Tariff (Exh. J-2), §§ 2.5.22.2, 2.5.22.3. The Load would thus continue to be served.

In order to ensure this continued service of behind-the-meter Load, the ISO's monitoring systems must be operating 24 hours a day; ISO personnel must be prepared to dispatch units 24 hours a day; and both the ISO Controlled Grid and the remainder of the transmission system in the Control Area must be planned, scheduled, and maintained so that those facilities can transmit the necessary Energy at any time, 24 hours a day. *See* Exh. S-1 at 7:15-17;. ISO-10 at 19:10 – 20:1, 21:11-15, 26:6-13, 28:15 – 29:4; ISO-29 at 13:1 – 2; Tr. 2046:11 - 2047:24, 2058:4-9.

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electricity does not always follow a direct path from Generation to Load, and that behind-the-meter transactions may to some degree flow over the ISO Controlled Grid. Tr. 1146:18-22.

Moreover, potential Generation failure is not the only concern. A transmission failure can have similar consequences. Tr. 2058:4-9. Further, the Generation and Load behind-the-meter are in a continuous state of flux. Tr. 1204:3-23; 2037:5-8. These fluctuations contribute to constant deviations in the ACE, which the ISO must likewise correct on a constant basis. Tr. 1320:14-23. The ISO's systems and personnel in fact respond to these deviations continuously. In addition, the ISO must ensure at all times the maintenance of voltage levels if the behind-the-meter Generation is to be able to serve the behind-the-meter Load. *See* Tr. 1002:13-17. All of these services require adequate, properly planned, and well-maintained transmission capacity. *See*, *e.g.*, Exh. ISO-10 at 19:10 - 20:1; 21:14-15, 26:6-13.

These practical considerations are themselves sufficient evidence of the benefits that behind-the-meter Load receives from the ISO's performance of CAS. It is worth noting, however, that these benefits are also reflected in the WSCC definition of the ISO's Control Area "load responsibility": the "Control Area firm load demand."[19] That responsibility is not limited to the Demand of Load served from the ISO Controlled Grid; it includes *all* firm load in the Control Area, regardless of by

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19 CAC/EPUC has attempted, through testimony, *see* Exh. CAC-4A at 14:11 - 16:12, and cross-examination, *see* Tr. at 1273:17 - 1275:14, to show that the definition of "load" and "system" used in the NERC Operating Manual limits load responsibility to load measured at certain points under the operational control of the ISO. On its face, this argument fails. One cannot apply definitions created for one specific set of procedures to another set of procedures that are created by a different organization and do not even refer to the definitions in the first set. *See* Exh. ISO-43; Tr. 2062:10 - 2064:21. The CAC/EPUC interpretation would lead to absurd results: it would exclude from the ISO's load responsibility all Load connected to distribution systems (which constitutes the vast majority of Load) because those systems are under the control of a different utility. *See* Tr. 1268:24 - 1269:8, 1341:17-22. It also ignores NERC's own "Glossary of Terms," which was issued to establish uniform definitions in the electric industry, and which includes the combined systems of electric utilities and Independent Power Producers in the definition of "System." *See* Exh. ISO-38. Even more to the point, it would require disregard of WSCC's own definition of "System," which parallels that in the Glossary. *See* Exh. ISO-43. Most importantly, this semantic argument obscures the real issue: whether as a practical

whom it is served and from what portion of the grid. *See* Exh. ISO-10 at 13:6-11;. ISO-30 at 11:11-17. The Commission-approved ISO Tariff requires the ISO to establish a WSCC approved Control Area, ISO Tariff (Exh. J-2) § 2.3.1.1.1, and to operate the ISO Controlled Grid according to criteria no less stringent than those of the WSCC, ISO Tariff (Exh. J-2) § 2.3.1.3.1. Although the latter provision only refers specifically to the ISO Controlled Grid, the ISO's responsibilities under its Tariff are more pervasive. The ISO Tariff requires the ISO to become a Control Area operator, ISO Tariff (Exh. J-2) § 2.3.1.1.1, and the WSCC criteria require the Control Area operator to maintain the reliability of the Control Area. Exh. ISO-11 at 29. If the ISO does not fulfill its Control Area responsibilities, it is thus operating the ISO Controlled Grid in violation of WSCC criteria and in violation of its Tariff.

That certain governmental entities ("GEs") with behind-the-meter Load may self-provide Ancillary Services, (*e.g*., Operating Reserves or Regulation), Tr. 1047:18-21, 2746:10-24, does not diminish their reliance on the CAS provided by the ISO. CAS is *not* a charge for Ancillary Services. Exh. ISO-29 at 12:11-14; Tr. 1984:2-8. If an entity self-provides Ancillary Services, it avoids the cost of procuring those Ancillary Services from the ISO. Tr. 2746:13-15. Regardless of how the Ancillary Services are procured or self-provided, however, it is the ISO that bears the expense of employing those services. The ISO must monitor the Ancillary Services. Tr. 1984:12-25. If the behind-the-meter Load contributes to an Energy imbalance, it is the ISO's ACE that shows the imbalance. Tr. 1349:15. All the units with AGC

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matter the ISO must take behind-the-meter Load into account in ensuring the reliability of the Control Area providing Regulation service to the ISO respond, not just the GE's Regulation units. Tr. 1349:18. The Imbalance Energy from those units will flow over the ISO Controlled Grid and other Control Area facilities, Tr. 1349:21, whose reliability the ISO assured through scheduling, analysis, planning, and maintenance coordination. Exh. ISO-29 at 13:1 – 14:22. It is the ISO that will identify and dispatch the Imbalance Energy bids that will be used to bring the Regulation units back to their preferred operating points. Tr. 1349:23 - 1350:1; ISO Tariff (Exh. J-2) § 2.5.22.2. That Energy, too, will flow over the ISO Controlled Grid and other Control Area facilities. *See, e.g.*, Tr. at 1354:13.

The ISO acknowledges that CAS may benefit different entities to different degrees. Tr. 1955:5 - 1957:18. Behind-the-meter Loads that admit they benefit from CAS, but contend that they should be charged less because they benefit less, are in reality asking for the more service categories. Additional service categories may well be appropriate in the future. *See, e.g.*, Tr. 1537:21 - 1538:2. As previously noted, however, the ISO need not show that the current proposal is the best of all possible unbundling proposals; it need only show that *this* proposal is just and reasonable. This is a good first step and a significant improvement from the bundled GMC. *See*, *e.g.*, Exh. ISO-1 at 21:4-7 and 20-23, 22:1 - 23:13. It provides a just and reasonable allocation of the costs among *all* parties, including behind-the-meter Load, that benefit from the ISO's services, and it avoids the prejudice that intervenors' sugges-

grid.

tions would make inevitable: a cost-shift to entities that already bear their fair allocation of CAS charges.

Issue I.F: Retail Customer-Owned Generation Issues.

Sub-Issue I.F.1: Is the Assessment of (I) the Control Area Services Charge and/or (ii) the Market Operations Charge on the Basis of a Retail Customer's Load Served by Generation Located Behind the Site Boundary Meter Just and Reasonable and Not Unduly Discriminatory?

For the most part, behind-the-meter Load served by qualifying facilities ("QFs") and other distributed generation[20] benefit from CAS in the same manner as other behind-the-meter Load. The efforts of various parties to distinguish behind-the-meter Loads served by QFs either fail or do not justify disparate treatment.

Although Mr. James A. Ross, witness for the Cogeneration Association of California and Energy Producers and Users Coalition ("CAC/EPUC"), alluded to the high reliability of QFs, Exh. CAC-2 at 30:11-15, he acknowledged that he had no empirical evidence that QFs were more reliable and did not rely upon such reliability in his recommendations. Tr. 2073:20 - 2074:12; 2102:15 - 2103:11. Similarly, although he asserted that the ISO's policies would discourage QF Generation and cause existing QFs to "island," *i.e.*, disconnect from the electrical grid, Tr. 2012: 4-12, he offered no supporting evidence. Mr. Ross has conducted no studies using the financial data of real QFs to support his assertions regarding the discouragement of QF Generation. Tr. 2015:1 - 2018:6. His more generalized analysis omitted *entirely* the cost of Energy. Tr. 2018:7-15. The Energy costs that can be avoided by self-generation overwhelm the costs evaluated by Mr. Ross. *See* Exh. ISO-42. It is impossible to evaluate the benefits of self-generating without considering those costs. Mr. Ross' testimony that existing QFs would island is the anecdotal evidence that one very small QF islanded *prior to* the allocation of ISO charges to behind-the-meter Load.[21] Tr. 2021:1-13. Such evidence proves almost nothing.

It is true that, absent a Generating Unit failure and discounting imbalances attributable to Generation and Demand fluctuation, Energy flows from the ISO-Controlled Grid to behind-the-meter Load are likely to be negligible. Tr. at 1287:8-13. This, however, does not significantly affect the benefit to behind-the-meter Load receives from CAS. That the Energy from the behind-the-meter Generation serving the behind-the-meter Load does not ordinarily flow on the ISO Controlled Grid does not change the fact that the ISO must at all times be prepared to serve the behind-the-meter Load in the case of Generation failure, that the ISO must continuously address imbalances between the Generation and Load, and that the ISO must ensure reliable transmission facilities in order to accomplish these tasks. *See* ISO-29 at 13:1 - 15:1.

This is not the first time that a party has argued to the Commission that it should be excused from transmission grid-related costs because the actual flow of Energy did not entail use of the ISO Controlled Grid. Docket Nos. ER97-2358-002,

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[20] For the purposes of this discussion, the ISO will use the term QF to refer to QFs and other forms of distributed generation in which the contract path between the Generator and Load does not involve the transmission grid or the distribution system of a UDC.

[21] Mr. Ross relies in this regard on testimony of Mr. Mark Minick, Tr. 2021:5-9, filed in November, 2000, before the Commission had even accepted the unbundled GMC for filing. Even today, the ISO is not enforcing the metering of behind-the-meter Load pending a Commission decision in the QF-PGA proceeding (Docket No. ER98-997-000). Tr. 1842:4-13. Accordingly, behind-the-meter Load is not allocated costs that are determined by metered Demand, such as Ancillary Services. ISO Tariff (Exh. J-2) at § 2.5.20.1.

et al., involved the Transmission Owner Tariffs ("TOTs") and the Wholesale Distribution Access Tariffs ("WDATs") of Southern California Edison Company ("Edison"), Pacific Gas and Electric Company ("PG&E"), and San Diego Gas & Electric Company ("SDG&E"). The TOTs established the rates for the use of the ISO Controlled Grid. The WDATs provided service from a Generating Unit to the ISO Controlled Grid or from the ISO Controlled Grid to a Load for wholesale customers. Enron asked the Commission to direct the IOUs to offer service on the distribution system directly from a Generating Unit to a Load, without use of the ISO Controlled Grid, if the Generating Unit and Load were located on the same radial arm of the distribution system. *See Pacific Gas and Electric Co., et al.,* 88 FERC ¶ 63,007 (1999) (exceptions pending).

Like parties here, Enron objected to being charged the GMC in connection with transactions that (based on the flow of electrons) did not use the ISO Controlled Grid. 88 FERC at 65,072-73. It too argued that distribution-only Generating Units were often extremely small. *Id*. It contended that 100 percent of the Generating Unit output flowed directly to Load without even entering the ISO Controlled Grid. It asserted that "distribution-only" service presented net reliability benefits, not added problems, to the ISO Controlled Grid. *Id*.

The comments of Administrative Law Judge Stephen Grossman in response to the arguments advanced by Enron are particularly instructive:

> . . . Provision of wholesale distribution-only service would unjustly permit a customer . . . to avoid its share of the costs associated with the construction, maintenance, and operation of the ISO Grid. The

> ISO-controlled Grid is the very backbone of the service that Enron proposes to implement . . . . [D]istribution-only service would have numerous effects on the ISO grid, and can not be performed in isolation from the ISO grid.
>
> The ISO is responsible for ensuring that there are adequate resources to serve the loads located on both the transmission and distribution systems. The ISO is also responsible for all reliability needs and Ancillary Services for the distribution system; even those that are completely radial in nature. To fulfill these responsibilities, among others, the ISO must use the ISO Grid in acquiring capacity and energy to balance loads and satisfy reliability requirements, regardless of whether the load is served off of the transmission facilities or off the Companies' distribution facilities. Even if a very small generator trips, the problem would be instantaneously resolved by the ISO's automated generation control. In light of this, Enron asserts that the ISO does not need to know about the hypothetical distribution-only transactions which Enron proposes. The technical fallacy of such an argument is self-evident.

(*Id*.) (Citations omitted.) In every regard, this reasoning is applicable to behind-the-meter Load served by QFs.

The Commission recently reached a similar conclusion regarding the ISO's proposal to charge on a total *gross* Load basis for emissions and start-up costs incurred by Generating Units dispatched by the ISO under a must-offer obligation. *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, et al.*, 97 FERC ¶ 61,293 (2001). Although parties argued that the ISO's proposal violated the principle of cost-causation by allocating charges to customers who do not benefit from ISO-dispatched generation, and pointed to the ISO's inability to measure the Control Area *Gross* Load of behind-the-meter Loads, *id*. at 62,369, the Commission nonetheless concluded:

> [T]otal gross load is the most appropriate method to assess these costs. … [T]he ISO provides imbalance service needed for reliable transmis-

> sion service. Additionally, … the Commission issued an order which stated that ISO market purchases are made in order to procure the resources necessary to reliably operate the grid. We have previously found that the use of gross load is the appropriate billing unit for the ISO's open access transmission access charge. Accordingly, the use of gross load as the basis for the assessment of emissions and start-up fuel costs is 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 62,320.

Finally, CAC/EPUC assert that behind-the-meter Load served by QFs already pays the charges that are appropriate through their acquisition of Standby Service. *See* Exh. CAC-2-A at 12:9 - 13:29. Under Standby Service, Utility Distribution Companies ("UDCs") sell Energy to QFs in the case of Generation failure or imbalances between Load and Generation. Exh. CAC -2A at 12:14-15; Tr. 2182:5 - 2183:13. Standby Service rates (and accompanying Energy rates) are the vehicles by which the UDC that is the SC for behind-the-meter Loads served by QFs recovers (in addition to other charges) costs assessed by the ISO, including GMC. Tr. 2183:2-21; Exh. ISO-34 at 9:12-22. Those recovered costs include a portion of GMC, but only an amount that reflects the amount of Energy delivered by the UDC (*i.e*., with a contract path on the ISO Controlled Grid). Tr. 2183:14-21.

This argument misses the point. The issue here has nothing to do with whether or how an SC recovers costs billed by the ISO. Rather, the issue involves the costs to be assigned to an SC on account of behind-the-meter Load. If the Commission ultimately decides – as the ISO believes it should – that CAS should be based on

Control Area Gross Load and billed to UDCs as SC, then it is the UDC's responsibility to seek to pass those costs on. Indeed, Edison has already done so. Tr. 2184:8-13.

Moreover, by providing Standby Service, UDCs are not reducing in any manner the need for CAS. Edison, for example, schedules an amount of Generation to meet a predicted standby Load. Tr. 2181:11 - 2182:4. If, however, Edison's real-time Generation and Load are not in balance – including when the portion representing QF Load varies from the predicted level – the ISO's systems respond as described in Section I.F. [22] Tr. 2045:3 - 2046:6, 2182:5 – 2183:1. That the UDC may schedule a predicted amount of standby Load thus does not relieve the ISO of the need to monitor imbalances from whatever cause and use the ISO Controlled Grid to respond to them.

Sub-Issue I.F.2: Is the ISO's Proposal to Estimate a Retail Customer's Load Served by Generation Located Behind the Site Boundary Meter Just and Reasonable?

Because the ISO does not have meter data on behind-the-meter-Load served by QF Generation, and because neither the QFs themselves nor the UDCs providing the Standby Service have provided the necessary Load information, some method of estimation is necessary to determine the portion of Control Area Gross Load that is served by on-site generation. Exh. No. ISO-1 at 12:11 - 13:19; Tr. 816:11-19. The use of an estimate is provided for in the Scheduling and Billing Protocol ("SABP") of the ISO Tariff , (Exh. J-2) SABP § 3.1, *See also* Tr. 774:14 - 775:24.

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[22] Even if the QF is generating sufficient Energy to serve an increase in the behind-the-meter Load, the increased Energy consumed behind-the-meter will reduce the Energy delivered to the ISO Controlled Grid,

The specific estimation method proposed by the ISO, the contract demand method, uses the billing determinants for the Demand component of the UDC Standby Rate tariffs. Exh. No. ISO-12 at 8:6 - 12:16. This data was selected as a basis for the ISO's estimate because it is publicly available. *Id.* at 8:7-10. The ISO applies a load factor to the contract demand to obtain the billing determinant volume. *Id*. at 9:6-7. The load factor is based on the Load of the UDC's comparable class of full service customers. *Id.* at 9:7-15. In no manner is the particular performance of on-site Generation an element of the ISO's estimation method. As Mr. Price noted, whether Generating Units are on or off would not affect the ISO's estimate of on-site Load. Tr. 853:20 - 854:8.

Basing the load factor on the comparable customer class results in a conservative estimate of the Control Area Gross Load served by on-site Generation for those customers whose on-site Generation is less than their on-site Load, because while such customers would be supplying as much Energy as they are capable of supplying (that is, nearly 100 percent), the load factors of the comparable customer class tend to be less than 70 percent. Exh. ISO-12 at 10:16-22. For customers whose on-site Generation is greater than their on-site Load, the load factor of the comparable customer class is based on peak load – a reasonable analogy. *Id.* at 10:22 - 11:3.[23]

The ISO would prefer to have meter data to calculate Control Area Gross Load. Tr. 826:23-24, 845:16-17. Absent such data, or data provided by the UDC or

causing an overall imbalance and requiring the ISO to procure Imbalance Energy. Tr. 2039:12 - 2042:14, 2043:19 – 2044:3, 2045:3 – 2046:1.

[23] The comparable load factors used in the estimation process are found in Exh. ISO-13.

QF itself, an estimate is necessary, Exh. ISO-12 at 6:14-16, 12:4-10; Tr. 513:14-18, 519:14-17, and the ISO's estimation method is reasonable. No party presented evidence proposing any alternative methodology.

Issue I.G: Is it Just and Reasonable to Assess Components of the GMC on Mohave Participant Energy?

1. <u>Mohave Participant Energy Benefits from Control Area Services Performed by the ISO.</u>

The Mohave Power Plant and the Eldorado Transmission System are jointly owned by Edison, the Los Angeles Department of Water and Power, Nevada Power, and the Salt River Project. Exh. ISO-29 at 41:21 - 42:8, 44:7-10. Mohave Participant Energy ("MPE") is energy that originates at the Mohave Power Plant and is transmitted over the Eldorado Transmission System, but is associated with the share of the facilities owned other than by Edison. The Mohave Power Plant and the Eldorado Transmission System are within the ISO Control Area. *Id.* at 44:2-4.

The CAS charge recovers the ISO's costs of performing services that, as described *supra*, benefit the entire Control Area. The billing determinant of Control Area Gross Load and exports, *see* ISO Tariff (Exh. J-2) Proposed § 8.3.1, is based on the fact that all Control Area Gross Load and exports benefit from CAS and cause CAS costs to be incurred. *See* I.E., *supra*.

The ISO's responsibility as Control Area operator allows no exception for MPE. Edison turned over Operational Control of the Eldorado Transmission System to the ISO, as evidenced by Appendix A of the Transmission Control Agreement, Exh. ISO-36 at 3:17 – 4:14, and the Transmission Registry, Exh. ISO-29 at 56:1 -

57:21; ISO-33. The ISO cannot maintain control over only part of a given facility. It must concern itself with the entire facility, or with none of it. Exh. ISO-36 at 5:7-16. Edison witness Mr. Mark R. Minick acknowledged as much. *See* Exh. SCE-19 at 8:7-11.

Because MPE originates in the ISO Control Area and is transmitted over transmission facilities that are under the Operational Control of the ISO, *see* Exh. ISO-32; ISO-36 at 4:19-5:2; Tr. 1231:23-24, MPE benefits from the CAS performed by the ISO in the same manner as does any other export. For example, MPE benefits from, *inter alia*, outage coordination; scheduling; the performance of operational studies; and the monitoring of the entire grid – all activities required of the ISO. Exh. ISO-29 at 46:16 – 52:25; Tr. 1205:9-12. It is the presence of MPE, along with the other users of the grid, that necessitates CAS and it is thus appropriate that MPE pay its fair share.[24]

2. <u>It is Not Discriminatory To Assess the Control Area Services Charge on Mohave Participant Energy</u>

Discrimination under the Federal Power Act requires 1) two entities or classes of customer that are similarly situated, and 2) disparate treatment for the same service. *See, e.g., City of Vernon v. FERC*, 845 F.2d 1042, 1045-46 (D.C. Cir. 1988). In the case of MPE and Southwest Power Link ("SWPL") Energy, neither prong of the test is satisfied.

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[24] In the discharge of its reliability responsibilities, it is important for the ISO to have information on all Load in, and exports from, the Control Area, including those related to MPE. The ISO must consider the entire output of the Mohave Plant, not just that element owned by SCE, in performing operational studies and outage planning. Exh. ISO-29 at 45:13-22. Of course, the reliability of the ISO system is of benefit to all Control Area Gross Load and exports, including MPE.

MPE and SWPL Energy are not similarly situated. Exh. ISO-36 at 6:1 - 7:15. SWPL Energy is Energy that is owned by joint participants in the Southwest Power Link other than SDG&E and is transmitted through the ISO Control Area.[25] As discussed above, MPE originates in the ISO Control Area, is dynamically scheduled to other Control Areas, and requires significant work by the ISO's systems and operators. SWPL Energy is known as a "Wheel Through", which consists of one part import and one part export. A "Wheel Through" transaction is deemed delivered by the ISO, and is considered the responsibility of the originating Control Area and the destination Control Area. The amount of workload that the two transactions place on the ISO is significantly different and warrants different treatment. Exh. ISO-36 at 7:14-15.

Because MPE and SWPL Energy are not similarly situated, and the services provided by the ISO for MPE and SWPL Energy are not identical, assessing the CAS charge on MPE but not on SWPL Energy is not discriminatory.

Issue I.H: Is it Just and Reasonable to Assess Components of the GMC on SWPL Energy?

The MO charge is intended to recover the ISO's market and settlement-related costs. *See* ISO Tariff (Exh. J-2) First Revised Sheet No. 333. That includes the administrative costs of providing Imbalance Energy. Imbalance Energy is necessary when an entity's schedule is not perfectly balanced, such as where transmission line losses occur between where the Energy enters the ISO Control Area and where the

[25] SWPL Energy does not originate nor serve Load in the ISO Control Area. *See* Exh. ISO-36 at 6:22 – 7:4.

Energy leaves the ISO Control Area.[26] To the extent SWPL Energy schedules require the ISO to procure Imbalance Energy because the SC for the transactions did not provide for losses, that is not covered in any other manner.[27] The provision of losses, in and of itself, is outside the scope of this proceeding. The real issue is whether procurement of Imbalance Energy should be treated differently depending on the use of the Energy. SDG&E is assessed the administrative costs of providing this Imbalance Energy for losses associated with SWPL Energy as part of the MO charge. *See* Exh. No. ISO-34 at 15:15 - 16:2. This is based upon the billing determinant for the MO charge: "…total purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy (both instructed and uninstructed)." *See* ISO Tariff (Exh. J-2) Proposed Section 8.3.3.

Other entities whose schedules result in Imbalance Energy costs associated with losses are also assessed the MO charge. The use of Imbalance Energy to meet losses is not different than the use of Imbalance Energy to meet Load. That SWPL is a joint ownership facility has no bearing on this issue. It is thus just and reasonable for SWPL Energy schedules to be assessed a share of the MO charge when Imbalance Energy is procured to cover losses.

[26] If 100 MW is put into the system at A, and there are 13 MW lost between point A and B, then only 87 MW exit at B. Thus for the Wheel Through transaction to be balanced, an additional 13 MW of Energy must be provided. Exh. ISO-36 at 15:17-20; Tr. 1903:2-17. This can be self provided or procured through the ISO's Imbalance Energy market.

[27] The ISO has an arrangement with SDG&E whereby SDG&E estimates the amount of Imbalance Energy necessary to cover the SWPL Energy losses, and thereby self-provides the Imbalance Energy for SWPL Energy losses. Exh. SDO-10. To the extent these estimates are not precisely accurate, however, certain additional Imbalance Energy may be necessary from time to time. It is for this additional Imbalance Energy that SDG&E is assessed the MO charge for SWPL Energy. Tr. 1902:4 - 1904:15.

Issue I.I: Is it Just and Reasonable for the ISO to Assess the GMC on "Other Appropriate Parties"?

The ISO proposed to charge "other appropriate parties" in connection with both CAS and MO costs. *See* Exh. ISO-27 at 8:12 - 9:23. The ISO has shown in section I.F that it is appropriate to assess CAS charges to GEs in connection with Loads that are served by internal Generation, *i.e.*, behind-the-meter. In addition, as shown in section I.J.3, the SC that is responsible under the Responsible Participating Transmission Owner Agreement ("RPTO Agreement") for an Existing Contract with a GE is ultimately responsible for the payment of the CAS in connection with the behind-the-meter Load. Nonetheless, the ISO has proposed, as a convenience to the parties, to charge CAS to the GE directly if, and only if, the GE agrees to such charges. *See id.* at 5:4-8; 9:2-11. Because this arrangement is voluntary on the part of the GE, relieves the SC of the burden of payment, and does not affect any Market Participant other than the SC and the GE, it should be considered just and reasonable.

There appears to be no controversy about the assessment of the MO charge based on sales and purchases in the ISO's markets. Certain entities that participate in the ISO's markets, however, are not SCs and have not signed Participating Generator Agreements. *See* Exh. ISO-27 at 9:14-23. Absent authority to charge "other appropriate parties," the ISO would have no mechanism for charging such entities their appropriate share of MO costs.[28] Section 8.3 of the proposed revisions to the ISO

[28] The alternative would be to require all entities participating in the markets to sign agreements. Exh. ISO-27 at 9:20-23. Unless the ISO were able to impose such a condition throughout the Western Interconnection, however, such a requirement would severely limit the ISO's ability to purchase Energy outside of its markets as necessary.

Tariff provides such authority. Entities transacting in the markets operated by the ISO presumptively are aware of the provisions of the ISO Tariff governing sales and purchases, including section 8.3, and thus are consenting to such charges.

Sub-Issue I.I.1: If So, Should the ISO be Required to Make a Compliance Filing to Allow it to Assess the GMC on "Other Appropriate Parties"?

As discussed above, the ISO believes that proposed section 8.3 of the ISO Tariff provides adequate authority for the ISO to charge "other appropriate parties." If the Commission concludes otherwise, however, the ISO believes a compliance filing would be appropriate to provide such authority.

Sub-Issues I.I.2: If Not, Should the Phrase "Other Appropriate Party" Be Deleted From the ISO's Tariff?

Not applicable.

Issue I.J: Is it Just and Reasonable to Assess a Scheduling Coordinator the GMC for Loads Not Scheduled Pursuant to the ISO Tariff By any Scheduling Coordinator?

This issue comprises two aspects of billing the CAS component: (1) whether a UDC should be billed the CAS charge for Load served by QFs within its service territory (Issue I.J.1), and (2) whether an entity that schedules transactions on the ISO Controlled Grid pursuant to an Existing Contract with a GE is responsible for CAS charges in connection with the portion of that GE's behind-the-meter Load that is not scheduled on the ISO Controlled Grid (Issue I.J.3).

Sub-Issue I.J.1: Is it Just and Reasonable for the ISO to Allocate in Any Hour the Control Area Services Charge to a Utility Distribution Company That Provides Standby Service to a Retail Customer (Including the Readiness to Provide Energy to the Customer Upon Demand), to the Extent Such Customer's Load is Fully Self-Served During That Hour?

The ISO has shown in Issue I.F.1, *supra*, that it is just and reasonable to allocate CAS to retail behind-the-meter Load. The issue here is the entity responsible in the first instance for paying those costs.

The ISO Tariff defines End-Use Customer (or End-User) as "A purchaser of electric power who purchases such power to satisfy a Load directly connected to the ISO Controlled Grid or to a Distribution System and who does not resell the power." ISO Tariff (Exh. J-2), Appendix A. Behind-the-meter Loads that take Standby Service from a UDC are thus End Users.

A UDC that provides Standby Service to a retail customer is the SC for that retail customer. Although some parties have suggested that the responsibility to serve as an SC does not apply during any hour in which the retail customer is served entirely by behind-the-meter Generation, Tr. 1846:7 - 1847:15, that limitation is contemplated neither by the ISO Tariff nor by the SC Agreement. As described in section I.J.3, the responsibilities of a SC are not limited to scheduling Load and Generation. Indeed, much of the standby Energy delivered by a UDC is not scheduled, Tr. 2182:5-24, but no UDC party has disclaimed responsibility for the CAS costs associated with unidentified, but delivered standby Energy, *see, e.g., id.*, (stating Edison would be billed for Imbalance Energy to meet QF Load in excess of scheduled Standby Service, and would pass the cost on). Rather, the responsibilities of a SC extend to paying charges in accordance with the ISO Tariff, ISO Tariff (Ex. J-2) § 2.2.6.1, ensuring compliance by each of the Market Participants which it represents with all applicable provisions of the ISO Protocols, *id.* § 2.2.6.9, and abiding by and performing all the obligations imposed by the ISO Tariff on SCs in respect to all matters set forth therein, *id.* at Original Sheet No.359 .

Under the terms of the ISO Tariff, Loads receiving Standby Service from a UDC are SC Metered Entities. ISO Tariff (Exh. J-2) Appendix A.[29] An SC is responsible for collecting revenue quality meter data from the SC Metered Entities that it represents. ISO Tariff (Exh. J-2) Metering Protocol § 1.3.2. The Commission-approved Metering Protocol also prohibits the netting of Generation and Load. (*Id.* Metering Protocol § 2.3.5). Because the billing determinant of CAS – Control Area Gross Load – is ordinarily measured by metered Demand, ISO Tariff (Exh. J-2) Settlement and Billing Protocol § 3.1, which must be gross Demand, it follows that the SC will be billed for, and is responsible for, the entire Load of a SC Metered Entity for which it is responsible, not simply for the net Load.

It thus further follows that a UDC that serves as a SC for End-Use Customers cannot limit its responsibility just to those hours during which the customer actually purchases Energy from the UDC. This is, of course, entirely consistent with a UDC's responsibilities as a regulated public utility[30] provide reliable service to entities within its service territory that require service, *see, e.g., Pinney & Boyle Co. v. Los Angeles*

[29] An End-User is only an ISO Metered Entity if directly connected to the ISO Controlled Grid and purchasing Energy from other than a UDC. *See* ISO Tariff (Exh. J-2) at Original Sheet No. 328.

Gas & Elec. Corp., 141 P. 620 (1914), including behind-the-meter Loads. CAS are part of the cost that the UDC pays to obtain the reliability that it must provide.

That the ISO has provided a temporary exemption from the gross metering requirements of the ISO Tariff, Tr. 1852:13-14, does not alter the responsibilities of UDCs that are SCs for entities taking Standby Service. The exemption is from the metering requirements, *not* cost responsibility.

Sub-Issue I.J.2: Is it Just and Reasonable for the ISO to Allocate the Control Area Services Charge (for Metered and/or Estimated Behind-the-Meter Retail Loads) to a UDC That Provides for Standby Service to a Customer if Such Customer Does not Procure Energy From a UDC, But Rather Procures its Energy From a Direct Access Energy Service Provider (i.e., an Entity Other Than the UDC) for Which the UDC is Not the Scheduling Coordinator?

It is not clear that the hypothetical upon which the issue is based is ripe for decision or that an actual case or controversy exists. No party has established the existence or likelihood of this practice within the ISO Control Area. Nevertheless, as noted above, a UDC that schedules Energy for a behind-the-meter Load is the SC for that Load. If a different entity acts as SC for the behind-the-meter Load by scheduling Energy or Ancillary Services, that SC, not the UDC, should be assessed the CAS charge on behalf of that behind-the-meter Load.

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[30] The ISO Tariff defines a UDC as an entity that owns a Distribution System and, *inter alia*, "provides

Sub-Issues I.J.3: Is it Just and Reasonable for the ISO to Assess the GMC to a UDC, When the UDC is Acting as a Scheduling Coordinator for a Wholesale Entity's Existing Transmission Contract, and All or a Portion of the Load of That Wholesale Entity Is Being Met by Means Other Than Transmission Service Provided Under the Terms of the Existing Transmission Contract?

Entities, such as PG&E and Edison, that schedule on the ISO Controlled Grid in accordance with existing transmission contracts or Interconnection Agreements have entered into a RPTO Agreement with the ISO. *See* Exh. SMD-17. For example, under Section 2.3 of its RPTO Agreement, PG&E agreed to be the SC for certain GEs with which it has Existing Contracts. *See, e.g.,* Ex. SMD-17 at unnumbered 11. Those GEs (along with the Existing Contracts) are identified in Appendix A to the RPTO Agreement and include all of the GEs that are parties to this proceeding. Exh. ISO-27 at 5:10-22, 7:1.

Although some have argued that an RPTO is only a SC to the extent that it actually schedules Energy for a Load with Generation behind a meter, *no such limitation appears in the RPTO Agreement.* Moreover, such a limitation would make little sense. As repeatedly demonstrated in this proceeding, the Existing Contracts that are identified in the RPTO Agreement may require the GE and the RPTO to perform various tasks that assist, or are necessary for, the Control Area operator's fulfillment of its reliability functions, and may also establish the cost responsibility for those tasks. *See, e.g.,* Exh. SMD-24 § 4.12.2. Because the ISO has assumed the functions of the Control Area operator, but not the assignment of these Existing Contracts, it must rely upon the former Control Area operator (*i.e*., the RPTO) to fulfill its respon-

regulated retail electric service." ISO Tariff (Exh. J-2) at Appendix A.

sibilities under the Existing Contracts and to ensure the GEs' fulfill theirs. These responsibilities pertain to the entire Load of the GE, not just the portion scheduled. *See*, *e.g.*, *id.* § 4.12.2; Exh. MID-12 § 4.1.

Further, nothing inherent in the role of a SC suggests that the RPTO's responsibility extends only to scheduled Load. Under the ISO Tariff, the first identified responsibility of a SC is to pay the ISO's charges in accordance with the Tariff. ISO Tariff (Ex. J-2) § 2.2.6.1. The SC must ensure compliance by each of the Market Participants that it represents with all applicable provisions of the ISO Protocols. *Id.* § 2.2.6.9. Similarly, the SC Agreement requires that SCs abide by and perform *all* the obligations placed on SCs by the ISO Tariff, without exception. *Id*. at Original Sheet 359.

The syllogism is simple: The RPTO Agreement requires the RPTO to act as SC for the GE, without limitation. The SC Agreement requires the SC to abide by the ISO Tariff. The proposed ISO Tariff provisions require certain payments by the SC associated with behind-the-meter Load. Thus, the Presiding Judge should find that the SC that has an Existing Contract with a GE that is identified in the RPTO Agreement is responsible for the CAS assigned to the GE's behind-the-meter Load.

Issue I.K: BART Issues

Sub-Issue I.K.1: Is the ISO's Market Operations Function Necessary and Beneficial to BART?

The Bay Area Rapid Transit District ("BART") takes service under an Existing Contract from PG&E *over the ISO Controlled Grid.* Exh. BRT-1 at 5:14-17. PG&E

could not schedule service for BART if it did not pay for any necessary Ancillary Services that are not self-provided and for Imbalance Energy associated with those schedules. ISO Tariff (Exh. J-2) at § 2.5.20.1, 11.2.4. *A fortiori*, BART benefits from MO because its energy could not be scheduled without MO. Whether BART has contracted with PG&E to provide scheduling services may be relevant to PG&E's ability to recover from BART, but does not affect the benefits BART receives.

Sub-Issue I.K.2: Are the ISO Activities and Costs Accounted for Under the ISO's GMC Function "Control Area Services" Essential or Beneficial to BART's Network Transmission Service?

Because PG&E provides transmission service to BART *over the ISO Controlled Grid*, Exh. BRT-1 at 5:14-17, BART necessarily benefits from CAS. Without the reliability that CAS provide on the ISO Controlled Grid, BART could not have reliable transmission service. Whether BART has contracted with PG&E to provide scheduling services may be relevant to PG&E's ability to recover from BART, but does not affect the benefits BART receives from the ISO.

Issue I.L: What Measures are Appropriate to Track and Control the ISO's GMC Costs?

Even though it is a non-profit entity, the ISO has incentives to keep its costs low. Exh. ISO-21 at 8:9 - 10:10; Tr. at 195:19 - 196:20, 200:8-18. For example, the ISO is subject to regulatory oversight and has a mandate to operate the system efficiently under state law,[31] ISO-21 at 8:9-18; Tr. at 196:1-9, and employee compensation is tied to meeting performance goals, which include cost-effective operation of

[31] Further, during 2001 budget preparation, the ISO was governed by stakeholder representatives of entities that will shoulder the responsibility for payment of the GMC.

the grid, Tr. at 207:24 - 208-23. Accordingly, the ISO has in place appropriate mechanisms to control and track costs.

All capital projects are subjected to a cost/benefit analysis before commencement, notwithstanding their previous inclusion in the capital budget by the Board. Exh. ISO-16 at 9:15-21; Tr. 485:21-24. Exhibit ISO-21 identifies other management mechanisms to discipline costs, including benchmarking ISO costs against peers, contract renegotiations, converting contract employees to permanent employees where a cost savings will result, and documenting alternatives to major initiatives to be approved by the ISO Board. Exh. ISO-21 at 9:6-10; 20:10-14. These efforts have included "top to bottom" reviews of all aspects of the ISO's operations during the ISO budgeting process. *Id*. at 8:2-5. Further, the ISO budgeting process is an open process, one with built-in opportunities for stakeholder input and review. *Id.* at 9:21 – 10:10; *see* discussion under I.A., *supra*.

The ISO has tracked costs to the extent feasible, directly assigning costs where possible. *See* Exh. ISO-7 at 13:17 - 17:22. Other than use of time-cards, no witness has offered any concrete example of what more should be done, and time slips could well prove counterproductive. Exh. ISO-21 at 39:9 - 43:2. The ISO has undertaken to investigate the costs and benefits of time-cards and has taken steps to put the framework for a time keeping system in place if it is determined to be beneficial. *See* Tr. 463:14-23.

Issue I.M: How Often Should the ISO be Required to Make a Section 205 Filing?

The ISO supports, in general, establishment of revenue "triggers" at 10 percent of the ISO's total revenue requirement and the greater of $5 million or 10% for individual categories. PUC-1 at 4:13 - 5:8; ISO-21 at 15:13 – 16:6; 16:8 - 18:8. Without that type of flexibility, the ISO's ability to respond to the uncertainties that will continue until the restructured California market is far more mature would be severely hampered, with prejudicial consequences for SCs and their ultimate consumers. Exh. ISO-21 at 17:1-13. The ISO does not oppose requiring Section 205 filings for changes to the structure of the GMC including, *e.g.*, to the service categories, Tr. at 443:15-24, or to increases in the revenue requirement in excess of reasonable "triggers." The ISO, however, must and should have the flexibility, without need of a rate filing, to make adjustments to the revenue requirements for the service categories that are certain to occur due to minor changes in budgeted amounts and cost allocations from year to year.

Additionally, the ISO requires the ability to change rates quarterly to deal with revenue shortfalls (or over-collections) attributable to lower (or higher) than anticipated billing volumes for each service category. Accordingly, Schedule 1, Part B of the ISO Tariff would allow prospective changes on a quarterly basis to the ISO's billing determinant volumes under certain conditions without a Section 205 filing. Tr. at 445:9-12, 446:10-15. Such an adjustment based on actual experience is analogous to a fuel adjustment clause, and thus appropriate in an otherwise fixed rate. *See* *generally Public Serv. of New Hampshire, et al. v. FERC*, 600 F.2d 944, 948 (D.C. Cir. 1979). Similarly, the ISO, supported by Staff, Tr. 2701:3-6, believes that no Section 205 filing is required from one year to the next if only the anticipated volumes of one or more billing determinants change.

Sub-Issue I.M.1: Should Additional Cost Control Measures be Implemented by the ISO to Avoid Section 205 Filings?

The ISO's cost control measures, reviewed under Issue I.L., *supra*, should allow it to remain under the overall and per-category revenue requirement trigger proposed by Mr. Ramirez.

Sub-Issue I.M.2: Should any modifications to the GMC methodologies, allocations, and structure be allowed without prior FERC review and approval?

The ISO does not oppose requiring Section 205 filings for changes to the structure of the GMC including, *e.g.*, to the service categories, Tr. at 443:11-14. Because the ISO's organizational structure continues to evolve in response to changing needs, however, it is important that the ISO retain the flexibility to modify the methodology for the allocation of cost centers (as described in the CAM) and the allocations to the three categories, so long as the 'triggers' are not exceeded, without a Section 205 filing. *See* Exh. ISO-21 at 63:8 - 64:18.

Issue I.N: Should the ISO be required to undertake a comprehensive re-evaluation of the GMC structure in 2003?

The ISO agrees with recommendations for a comprehensive stakeholder review of the GMC structure during 2003. Exh. ISO-21 at 62:9-11, 19-22. By that time, California markets may be sufficiently stable for the ISO to establish its allocations and methodologies in a formula rate that satisfies the criteria set out by Mr. Pointer in his testimony. Exh. S-6 at 12:24-28. That review would be an appropriate forum to explore many of the suggestions made by intervenors in this proceeding.

Sub-Issue I.N.1: What procedures and time frames should be followed for GMC re-evaluation?

See Issue I.N.

Sub-Issue I.N.2: How should customer input be solicited and incorporated?

As in the stakeholder process for the unbundling of the GMC, customers should provide input through meetings and comments on reports.

Sub-Issue I.N.3: Should the ISO be required to file the results of future evaluations of the GMC with the FERC for review and approval?

The ISO does not oppose requiring filings under Section 205 of the FPA for changes to the GMC revenue requirement above the trigger discussed above, service categories, or billing determinants.

Issue I.O: Is the ISO's formula rate specific enough to operate as a formula under the Commission's regulations?

See discussion of proposed "trigger" under Issue I.M, *supra*.

Sub-Issue I.O.1: Should the ISO be required to make a Section 205 filing if the results of its formula exceed the revenue requirement caps for each GMC component?

See discussion of proposed "trigger" under Issue I.M, *supra*.

Sub-Issue I.O.2: Should the ISO's GMC components have revenue requirement ceilings and if so, what is the appropriate level of such ceilings?

See discussion of proposed "trigger" under Issue I.M, *supra*.

Sub-Issue I.O.3:Should the ISO's formula rate be replaced by either of the options proposed by Mr. Pointer in his testimony or the option presented by Mr. Ramirez in his testimony?

See discussion of proposed "trigger" under Issue I.M, *supra*.

Issues II.A Through II.C

The ISO takes no position at this time on issues II.A through II.C.

IV. CONCLUSION

WHEREFORE, for the reasons discussed above, the Presiding Judge should find that the ISO's GMC filing is just and reasonable.

Respectfully Submitted,

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Date: January 25, 2002

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all parties on the official service list compiled by the Secretary in the above-captioned proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, DC this 25th Day of January, 2002.

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