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July 1, 2002

VIA COURIER

The Honorable Magalie R. Salas
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 Salas:

Enclosed for filing are one original and 14 copies of the California Independent System Operator's Brief Opposing Exceptions in the above captioned proceeding. Also enclosed are two extra copies of the filing to be time/date stamped and returned to us by our messenger.

Thank you for your assistance with this matter.

Respectfully submitted,

Theodore J. Paradise

Theodore J. Paradise

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**

BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION OPPOSING EXCEPTIONS

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Dated: July 1, 2002

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BRIEF OF THE
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OPPOSING EXCEPTIONS

I. INTRODUCTION

Pursuant to Rule 711 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.711 (2001), the California Independent System Operator Corporation ("ISO") submits this Brief Opposing Exceptions.

II. SUMMARY

In this brief, the ISO will demonstrate that the exceptions to the Initial Decision[1] in this proceeding of the other parties are without merit. In section A.1, the ISO explains that the Initial Decision properly determined that the ISO's revenue requirement is just and reasonable and this determination is fully supported by the evidence. The ISO demonstrates that the Initial Decision did not shift the burden of proof from the ISO, but in fact found that the ISO had met its burden of proving the Grid Management Charge ("GMC") is just and reasonable. The Initial Decision was correct in finding the ISO's estimates of its costs were reasonable when made.

In section A.2, the ISO explains that the Initial Decision correctly refrained from ordering the ISO to refund over-collected incentive compensation, because amounts collected in excess of the ISO's actual costs were returned via a credit to the 2002 GMC revenue requirement. In section A.3, the ISO demonstrates that the Initial Decision properly found that the ISO's estimated staffing levels were just and reasonable. The ISO explains that the fact that the ISO utilized temporary and contract employees rather than full-time employees in certain instances does not render its staffing estimates unreasonable.

In section A.4, the ISO discusses how the Initial Decision properly found that ISO's Operating and Maintenance budget should not be reduced by the amounts discussed in ISO management's November 9, 2000 Memorandum, because the ISO prudently determined that such reductions were inadvisable.

In section A.5, the ISO describes how the Initial Decision properly found that the ISO's forecast of costs associated with new debt to fund capital expenditures were just and reasonable, because despite the inability of the ISO to make a section 204 filing to secure financing through a bond issuance, the ISO intended to make such a filing at the time its rate case was filed.

In section B, the ISO explains that the Initial Decision properly found that the ISO's unbundling of the GMC into three service categories is just and reasonable, in light of the extensive stakeholder process the ISO undertook with the assistance and contributions of many of the parties to this proceeding. The ISO further explains that the Initial Decision correctly determined that the alternative unbundling proposal of Dr. Kirsch was insufficiently explained to be considered as a viable alternative.

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1 *California Independent System Operator Corporation*, 99 FERC ¶ 63,020 (2002) ("Initial Decision").

In section C, the ISO demonstrates that the Initial Decision properly concluded that any changes to the service categories, if necessary, are ordered, such changes should be prospective only, based on Commission precedent and on practical considerations as to the current structure of the ISO's accounting system.

The ISO supports the Initial Decision's finding that, based on record evidence, the ISO's cost allocations were just and reasonable in section D.1. In section D.2, the ISO demonstrates that the Initial Decision properly found that the ISO's use of headcount in 2001 was just and reasonable, based on the fact that a labor cost analysis produced by the ISO did not demonstrate a significant difference in allocations as compared to the headcount, and because the Commission has approved the use of the headcount methodology.

The ISO discusses how the Initial Decision was correct to find that the ISO's allocation of cost center 1424 (Information Technology Assets, Contracts and Change Management) was just and reasonable in section D.3. The ISO explains that direct allocation of this cost center was appropriate because the costs at issue support the operations of the entire ISO, necessitating the exercise of judgment in their assignment.

In section D.4, the ISO demonstrates that the Initial Decision properly found that the ISO's allocation of MCI contract costs was just and reasonable, because MCI has not provided the ISO with sufficient data to make a more direct assignment of the costs involved.

The ISO explains that the Initial Decision was correct to find that if changes to the ISO allocations are ordered, such changes should be prospective only in section E. The Initial Decision was correct in this regard because cost allocation is an element of rate design.

In section F, the ISO demonstrates that the Initial Decision properly concluded that the allocation of the Control Area Services ("CAS") Charge based on Control Area Gross

Load is just and reasonable, because 1) the Commission's order on Amendment 2 does not foreclose such an allocation; 2) cost causation principles justify such an assessment; and 3) the ISO is not contractually barred from allocating the CAS Charge to behind-the-meter load.

In section G, the ISO demonstrates that the Initial Decision properly found that it is just and reasonable to allocate CAS Charges to retail behind-the-meter load, based on the evidence that 1) the ISO's proposal does not violate Public Utility Regulatory Policies Reform Act ("PURPA"); 2) the ISO's proposal does not discriminate against Qualifying Facilities (QFs); and 3) such allocation is consistent with cost causation principles. Moreover, the ISO further demonstrates the Initial Decision in Docket No. ER98-997 does not control the outcome of this proceeding, and that the Initial Decision's ruling on this issue is consistent with public policy.

In section H, the ISO explains that the Initial Decision properly found that the ISO's methodology for allocating Control Area Services Charges to retail behind-the-meter loads is just and reasonable, because, absent the meter data necessary to assess QFs for their appropriate share of the CAS Charge, some form of estimate is necessary. Moreover, the ISO explains that there is no conflict between the use of the estimate and the terms of power purchase agreements.

In section I, the ISO demonstrates that Initial Decision was correct in finding it just and reasonable to apply the Control Area Services Charge to Mohave Participant Energy, as Mohave Participant Energy constitutes an export. In the same manner, in section J, the ISO explains that the Initial Decision was correct in finding it just and reasonable to assess the Grid Management Charge on schedule over the non-San Diego Gas & Electric Company elements of the South West Powerlink, as it constitutes an export and utilizes the ISO's Imbalance Energy market.

In section K, the ISO explains that the Initial Decision was correct in allowing the GMC to be charged to "other appropriate parties", and that concerns expressed by certain parties about uncertainty in how the term would be applied were unwarranted in light of the Initial Decision's finding that the ISO make a compliance filing providing detail on how the term would be used.

In section L, the ISO describes that, if the Commission agrees with the Initial Decision that the behind-the-meter Loads served by QFs are taking CAS from the ISO in connection with their internal loads, but also agrees with the Initial Decision that the ISO should not bill the Utility Distribution Companies for those CAS, then the Commission should direct the ISO to develop appropriate agreements to provide the necessary contractual privity. In the same manner, in section M the ISO explains that if the Commission agrees with the Initial Decision that the Governmental Entities ("GE") are taking CAS from the ISO in connection with their internal loads, but also agrees with the Initial Decision that the ISO should not bill the SCs for those CAS, then the Commission should direct the ISO to develop appropriate agreements to provide the necessary contractual privity.

In section N.1, the ISO demonstrates that the Initial Decision was correct to find that of San Francisco Bay Area Rapid Transit ("BART) benefits from the ISO's Market Operations, because BART's energy could not be scheduled without Market Operations. In section N.2, the ISO explains that the Initial Decision correctly found that the ISO's activities and costs accounted for under the Control Area Services Charge are essential and beneficial to

BART, because all Load in the Control area benefits from the ISO's Control Area Services, including that of BART.

Finally, in section O, the ISO explains that the Initial Decision was correct to determine that the issue of cost control measures is moot, since the ISO has made a section 205 filing for 2002, and that in any event the additional cost control measures proposed by other parties have not been supported.

III. STATEMENT OF THE CASE

A. The California ISO

The ISO is a California non-profit public benefit corporation, organized pursuant to the Nonprofit Public Benefit Corporation Law for the charitable purposes set forth in Chapter 2.3, Part 1, Division 1 of the Public Utilities Code of the State of California. The ISO, created at the direction of the California Legislature, is organized specifically to ensure efficient use and reliable operation of the electric transmission grid in the State of California. *See* Cal. Pub. Util. Code § 300, *et seq.* (West Supp. 1998); CPUC Decision No. 95-12-063 (Dec. 20, 1995), *as modified by* Decision No. 96-01-009 (1996), 166 PUR4th 1 (1996). The ISO is a "public utility" as that term is defined in Section 201 of the Federal Power Act ("FPA"), 16 U.S.C. § 824(e) (2000). The ISO has no stockholders and no rate-base on which to earn a return. As a result, the ISO has only one source of revenues – its Grid Management Charge ("GMC"). 99 FERC at 65,193; Tr. 218:13-14.

B. Procedural History

The ISO originally filed a GMC on October 17, 1997, as a bundled formula rate. The GMC was, and is, designed to collect the costs of operating the ISO, which include meeting the ISO's start-up and development costs, its ongoing capital expenditure costs, and its operation and maintenance costs. Exh. ISO-1 at 3:11-14. The GMC was designed to be a monthly charge assessed to all Scheduling Coordinators ("SC"s). *Id.* at 3:14-15. The filing of the original bundled GMC resulted in an uncontested settlement.[2]

The process of unbundling the GMC in concert with stakeholders began in early 1998, a few months after the filing of the original GMC. *Id.* at 8:22-23. That process assumed the form of a Stakeholder Steering Committee which selected a consultant to conduct the unbundling study required by the GMC Settlement, *id.* at 5:5-16, 9:1-21, and then worked with the ISO to develop the separate service categories and billing determinants for each, which were approved by the ISO's stakeholder-composed Governing Board on June 22, 2000. *Id.* at 8:22 – 11:18.

The instant case commenced with the filing of the unbundled GMC on November 1, 2000 in Docket No. ER01-313-000. The filing was noticed by the Commission on November 6, 2000. Multiple parties intervened in response to the ISO's filing.[3] On November 13, 2000, Pacific Gas and Electric Company ("PG&E") submitted for filing a proposed GMC

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2 *California Independent System Operator Corp.*, 83 FERC ¶ 61,247 (1998) ("GMC Settlement").

3 California Electricity Oversight Board ("EOB"), California Power Exchange Corporation ("CAL PX"), California Municipal Utilities Association, Calpine Corporation, Calpine Power, City of Anaheim, City of Azusa, City of Banning, City of Colton, City of Redding, City of Riverside, City and County of San Francisco ("CCSF"), City of Santa Clara, City of Vernon, Cogeneration Association of California ("CAC"), Dynegy Power Marketing, Energy Producer and Users Coalition ("EPUC"), Independent Energy Producers Association, Metropolitan Water District of Southern California, Modesto Irrigation District ("MID"), M-S-R Public Power Agency, Northern California Power Agency ("NCPA"), Pacific Gas and Electric Company ("PG&E"), Public Utilities Commission of the State of California ("CPUC"), Sacramento Municipal Utility District ("SMUD"), San Diego Gas & Electric ("SDG&E"), San Francisco Bay Area Rapid Transit District ("BART"), Southern California Edison Company ("SCE"), Southern Energy California, LLC, Southern Energy Delta, LLC, Southern Energy Potrero, LLC, Transmission Agency of Northern California ("TANC"), Trinity Public Utility District, Turlock Irrigation District ("TID"), Western Area Power Administration ("WAPA"), Western Power Trading Forum. The following parties moved to intervene out-of-time after the Initial Decision was issued: the California Cogeneration Council ("CCC"), Electricity Consumers Resource Council ("ELCON"), the United States Combined Heat and Power Association, the American Iron and Steel Institute, the American Forest & Paper Association, the American Petroleum Institute ("API"), the National Petrochemical & Refiners Association ("NPRA"), the Fertilizer Institute, and the Chemical Industry Council of California (collectively, "Industrial Associations"). The ISO has opposed these late interventions.

pass-through tariff designed to allowed PG&E to pass through the GMC to wholesale contract customers. PG&E's pass-through filing was docketed in ER01-424-000 and noticed on November 17, 2001. On December 15, 2000 the ISO submitted updated cost support. The ISO's December 15th filing was assigned to Docket No. ER01-313-001. PG&E subsequently amended its pass-through filing. PG&E's amendment was docketed in ER01-414-001. On December 29, 2000, the Commission accepted the ISO's unbundled GMC filing, the December 15th filing, and PG&E's pass-through tariff filings to be effective January 1, 2001, consolidated the dockets and set them for hearing. *California Independent System Operator Corp.*, 93 FERC ¶ 61,337 (2000).

The procedural history of the case up through the Initial Decision, issued on May 10, 2002, is included as part of the Initial Decision at pages 65,071- 65,073. In response to the Initial Decision, several parties filed briefs on exceptions.[4] In the instant brief, the ISO responds to the exceptions of other parties directed towards the portion of the Initial Decision that addresses the issues in ER01-313. Exceptions to the Initial Decision related to the PG&E pass-through tariff portion of the Initial Decision are not addressed.

IV. EXCEPTIONS OPPOSED

Because reciting the often repetitious narrative exceptions of the parties would consume several pages of this filing, we are listing the exceptions opposed by number. The ISO opposes the following numbered exceptions (including subparts to the numbers listed):

BART: 1-2

CAC/EPUC: 1-15

[4] BART, CAC/EPUC, CCC, CCSF, IA, MID, NCPA, PG&E, SCE, SDG&E, SMUD, Commission Staff, SVP, TANC, TID, WAPA.

CCC:	A-E[5]
IA:	1-5
MID:	1-4
SCE:	1-3
SDG&E:	1-5
SMUD:	1-2
TANC:	1-18

V. REBUTTAL TO POLICY CONSIDERATIONS WARRANTING REVIEW

Many of the policy arguments made in the various briefs on exceptions are simply distillations of a given party's exceptions. As such, they are addressed in the substantive argument opposing exceptions below. Only a few policy arguments constitute arguments that substantively vary from the parties' exceptions. These policy arguments are set out and addressed in the context of the issue arguments below.

VI. ARGUMENT

A. The Initial Decision Properly Determined That The ISO's Revenue Requirement Is Just And Reasonable [Section I.A of the Initial Decision]

The ISO's rate case is unusual in that, as a non-profit, public benefit corporation with no shareholders and no rate base on which to earn a return, the ISO seeks only to recover its *costs* and not the usual, and often contentious, return on equity. Exh. ISO-21 at 6. TANC is the only party that has excepted to the Initial Decision's finding that the ISO's 2001 revenue requirement is just and reasonable.

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5 CCC's Brief on Exceptions did not include a numbered list of exceptions. CCC's argument outline is being used in lieu of a numbered list.

1. The Initial Decision's Conclusion That The ISO's Revenue Requirement Is Just And Reasonable Is Fully Supported By The Evidence

a. The Initial Decision Did Not Shift The Burden Of Proof From The ISO

TANC alleges that the Initial Decision erroneously employed an incorrect legal standard that shifted the burden of proof to intervening parties. TANC BOE at 7. As discussed below, TANC's arguments regarding the burden of proof are misplaced. Nonetheless, whether the Initial Decision was mistaken about the applicable burdens does not affect the validity of its finding the ISO had met its burden of showing that its revenue requirement is just and reasonable.

TANC contends that the Initial Decision erroneously concluded that intervenors bore the burden of raising a substantial doubt about the validity of the ISO's revenue requirement. TANC BOE at 11-12. TANC ignores the Initial Decision's finding that "even assuming that 'serious doubts' have been raised by [various parties'] generalized challenge, the ISO has made a persuasive showing that although its revenue requirement has increased significantly, this was due in large part to the volatility of California's electricity markets and the increased number of tasks the ISO is expected to perform." 99 FERC at 65,079. In other words, the Initial Decision found that the ISO met its ultimate burden of proof, regardless of whether intervenors had a burden to raise a substantial doubt. The Initial Decision cites, as an example, the testimony of Mr. Leiber, Ex. ISO-21 at 6-8. Additional record testimony documents both the history of increasing ISO tasks and responsibilities – providing a reasonable basis for extrapolation of costs – and the specific projects and new tasks for 2001. Exh. ISO-22.

This evidence outweighs any generalized discussion of cost increases or any comparisons with other ISOs,[6] and supports the Initial Decision's conclusions.

Nonetheless, the error of TANC's legal analysis should be noted. In determining whether the ISO may recover its contractually committed and estimated costs for 2001, the Initial Decision correctly relied on Commission and judicial precedent establishing that when an entity is requesting a rate increase under Section 205 of the FPA, 16 U.S.C. § 824(d), its decisions to incur costs are presumed to be prudent and therefore may be recovered, 99 FERC at 65,075, and that revenue requirement estimates are to be upheld if they were reasonable when made, *Id.* at 65,076-77.

In this regard, the Initial Decision properly relied on the Commission's holding in cases like *Minnesota Power & Light Co.,* 11 FERC ¶ 61,312 (1980). *See* 99 FERC at 65,075. In *Minnesota Power*, the utility filed for a new rate under Section 205 of the FPA. In the course of reviewing whether a specifically challenged cost could be recovered, the Commission reviewed its standard regarding utility cost recovery. The Commission began this review by noting that:

> The burden of proof to show the increased rate or charge is just and reasonable shall be upon the public utility.

11 FERC at 61,644-45, citing Section 205 of the FPA. The Commission continued:

> As a matter of practice, utilities *seeking a rate increase* are not required to demonstrate in their cases-in-chief that all expenditures were prudent unless the Commission's filing requirements, policy or precedent otherwise require. However, where some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent.

11 FERC at 61,445 (footnotes omitted)(emphasis added).

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6 The Initial Decision accepted the ISO's explanation of why the attempted comparison to other ISOs

TANC also contends that the Initial Decision's reliance on *Minnesota Power* and similar cases is misplaced because their holding is limited to 1) "expended costs" or 2) "proposed changes to an approved rate filing." TANC BOE at 11. Although most prudence disputes have arisen in those contexts, prudence disputes are not limited to such circumstances. Prudence concerns the reasonableness of a management decision to incur expenses. *See generally New England Power Co.*, 31 FERC ¶ 61,047 (1985), *reh'g denied,* 32 FERC ¶ 61,112 (1985), *petition for review denied sub nom., Violet v. FERC,* 800 F.2d 280 (1st Cir. 1986). Whether the cost has been incurred, or is to be incurred, is not relevant. In *Williston Basin Interstate Pipeline Company*, 72 FERC ¶ 61,074 (1995), for example, the issue concerned the prudence, at the time the rate was filed, of a decision not to refinance in the test period – which followed the rate filing. The costs attributable to the failure to refinance had not yet been incurred when included in the rate, but the decision had been made.

A limitation under which the good faith of a utility may be presumed only with respect to costs it already has incurred would present a nonsensical distinction. Under TANC's position, a prudence evaluation would not have been appropriate before the ISO actually made, for example, an installment payment on its MCI contract, but the day after the payment, this standard *would* apply. There is no basis for this distinction, and TANC has cited no precedent for it.

In sum, the case law cited by TANC would not undermine the Initial Decision's holding that "generalized challenges" to the ISO's *costs* are insufficient to render any of

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was not persuasive. 99 FERC at 65,075, n. 11.

those costs unreasonable, 99 FERC at 65,075, regardless of whether the Initial Decision relied on a presumption of prudence.[7]

b. Estimated Costs Are Recoverable If Estimates Were Reasonable When Made

TANC argues that the standard to be applied in the present case is whether the cost estimates were reasonable when made. TANC BOE at 12. The ISO does not disagree.[8] Indeed, far from assuming that the ISO's estimates were reasonable, see TANC BOE at 5, the Initial Decision clearly states the standard relied on in determining whether the ISO's cost estimates were just and reasonable:

> Like other regulated utilities, the ISO must prove that its revenue requirement forecast was reasonable when made, "either by explaining the chain of reasoning that it employed to arrive at its projections, or by comparing the estimates with actual data and so establishing their accuracy." See *Delmarva Power and Light Co. v. FERC*, 770 F.2d 1131, 1139 (D.C. Cir. 1985) (quoting *Villiage of Chatham v. FERC*, 662 F.2d 23, 29-30 (D.C. Cir. 1981)).

99 FERC at 65,076-77. *See also id.* at 65,079 ("As previously indicated, the analytical framework which governs my review of this issue is not what costs were ultimately incurred, but what cost projections were reasonable when made"); *id.* at 65,080 ("The first issue that must be addressed is whether the ISO's inclusion of these costs ... was reasonable at the time of the filing"). TANC's allegation that this standard was not applied does not accurately reflect the substance of the Initial Decision.

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7 TANC's second postulated limitation on the prudence standard does not actually concern prudence cases. *Southern Company Services, Inc.*, 48 FERC ¶ 63,007 (1989), simply makes the point that in a Section 205 filing, a utility does not bear the burden of proof on those portions of the rate that have previously been approved and are not being changed. *See, e.g. Public Serv. Comm. of N.Y. v. FERC,* 642 F.2d 1335 (D.C. Cir. 1980). This means nothing more than that a utility need not litigate twice the same rate.

8 TANC notes that because it is only challenging the ISO's costs that were estimates at the time of its filing, it is not challenging any of the "expenditures on the ISO's books" *Id.*

Rather than shifting the burden regarding the ISO's estimates, as TANC alleges, the Initial Decision examined each of the challenges to the ISO's estimated costs, in all but one case finding that the ISO had met its burden of proof. *See, e.g.*, 99 FERC at 65,076-78. Several examples of the Initial Decision's review of the ISO meeting its burden of proof are presented immediately below.

With regard to the ISO's estimation of the number of employees the ISO would need to meet its workload in 2001, the Initial Decision reviewed the extensive record support for the number of employees the ISO projected it would need and found that the estimate was just and reasonable under the *Delmarva* standard, even though the number of permanent employees actually hired in 2001 not meet the ISO's projection. 99 FERC at 65,077-78. +The Initial Decision next reviewed the extensive record evidence regarding the reasonableness of the decision of the ISO's Finance Committee to include certain costs in the ISO's revenue requirement. In reviewing the Finance Committee's decision to include possible cost reductions outlined in a November 2000 memorandum, the Initial Decision noted that "the analytical framework which governs my review of this is not what costs were ultimately incurred, but what cost projections were reasonable when made." 99 FERC at 65,079. The Initial Decision concludes that the Finance Committee's determination to include the costs was reasonable when made. *Id.* The Initial Decision then reviewed the ISO's inclusion of funds to cover the cost of its debt service if a bond issuance were to be made in 2001. *Id.* at 65,079-80. Again, the Initial Decision addressed the issue by examining whether the estimation of debt service costs "was reasonable at the time of the filing." *Id.* at 65,080. The Initial Decision noted that "The record supports a finding that [the estimation of debt service costs] was [reasonable]." *Id.* In reviewing whether the ISO had met its burden with regard to an estimate of 100% incentive compensation, the Initial Decision reviewed the record evidence that the ISO had admitted a programming mistake that over-budgeted this amount. The Initial Decision thus found that the ISO had not met its burden of proof. 99 FERC at 65,076. The Initial Decision, therefore, applies the "reasonable when made" standard, as set out in *Delmarva,* to the ISO's various estimated costs and requires that the ISO meet its burden of proof under that standard. TANC's contention that this standard is not used and that the burden of proof was shifted from the ISO is, therefore, simply inaccurate and its arguments should be rejected.

2. The Initial Decision Correctly Refrained From Ordering The ISO To Refund Over-Collected Incentive Compensation, Because Amounts Collected In Excess Of The ISO's Actual Costs Were Returned Via A Credit To The 2002 GMC Revenue Requirement.

The Initial Decision determined that the ISO's budgeting for 100% employee incentive compensation, when it intended to budget for 73%, was not reasonable when made, in that it was over-stated by $1,834,267. *Id.* at 65,076-77. The Initial Decision deferred to the Commission on the question of whether a refund should be required. Only TANC contends that the Initial Decision should have recommended a refund.[9] TANC BOE at 13-15.

In considering the proper remedy for this over-statement, the Initial Decision had to take into account that the ISO's financial operating reserve mechanism credits all over-collected sums in one year back to market participants through use of a revenue requirement credit in the following year. 99 FERC at 65,077. Indeed, by November 2, 2001 – several months prior to the issuance of the Initial Decision – the ISO had already estimated actual 2001 spending in the 2002 rate filing, crediting any over-collected funds back to market par-

[9] The ISO has taken exception, as well, contending that the Initial Decision should have recommended that no refund be ordered. *See* ISO BOE at 5-7.

ticipants by reducing the 2002 revenue requirement. *See* Tr. 505:5-17, 507:12 - 508:3. Ordering of a traditional refund in addition to this credit would result in returning such over-collection *twice* and would result in the ISO's failure to recover its costs. 99 FERC at 65,194. Moreover, Commission Staff witness Stephen Pointer testified that use of the financial operating reserve to credit over-collections against the next year's revenue requirement would not result in problematic "generational shifting" (i.e., those who paid too much might not match exactly those who received the subsequent credit), because overpaid funds from one year are immediately returned in the next. Tr. at 2686:2-11.

In light of the above, the ISO submits that the Initial Decision was correct in not recommending a refund. Contrary to TANC's contention, *see* TANC BOE at 14, the Initial Decision did not suggest that the operating reserve mechanism might somehow "substitute" for the requirement of just and reasonable rates, or justify an "exemption" from Commission refund policy. The Initial Decision simply recognized the reality that the ISO is a non-profit public benefit corporation with a GMC that is designed only to recover the ISO's costs.

Further, while the ISO has demonstrated that it returns all over-collected funds to ratepayers, TANC has offered nothing to support its bald assertions that the ISO's operating reserve is insufficient to meet the Commission's ratemaking goals. TANC BOE at 14. TANC's arguments that "exempting" the ISO from "refunds" will result in "mischief" and "add momentum to the ISO's out of control budget process" are unsupported. TANC BOE at 15.

TANC's insistence on a traditional refund elevates form over substance and fails to recognize the import of the ISO's non-profit structure. The ISO presented testimony that the GMC is the ISO's only source of revenue, Tr. 218:13-14, and the Initial Decision so found, 99 FERC at 65,193. The real-world importance of this fact is that if a traditional refund were to be ordered, the refund would ultimately have to be funded by the very ratepayers receiving the refund. This is true even if a refund were to come from the ISO's financial operating reserve, as that account is also funded by the same GMC collections.

Given the ISO's non-traditional structure, and the facts that the ISO has already credited any overpaid amounts back to ratepayers, that a refund on top of that crediting would cause the ISO to under-recover its costs, and that any refund would ultimately be paid by ratepayers, TANC's arguments for a traditional refund are not logical. Whether to order refunds is always within the Commission's discretion[10] and the ISO submits that this is certainly a circumstance in which the Commission should exercise that discretion against refunds. If, however, the Commission does require the ISO to make a traditional refund in addition to the operating reserve credit, the ISO requests that the Commission allow the ISO to recover the operating reserve credit via a surcharge to ensure that the ISO does not under-recover its costs.[11]

3. The Initial Decision Properly Found That The ISO's Estimated Staffing Levels Were Just And Reasonable

TANC is the only party to take issue with the Initial Decision's finding that the ISO's estimate of its 2001 staffing needs was reasonable when made. 99 FERC at 65,077-78.

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10 *See, e.g., San Diego Gas and Electric Co. v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, et al.*, 97 FERC ¶ 61,275, at 62,185 (2001); *Consumer Advocate Division of the Public Service Commission of West Virginia, Maryland People's Council, and Pennsylvania Office of Consumer Advocate v. Allegheny Generating Company*, 68 FERC ¶ 61,207 at 61,997 (1994).

11 The Market Participants had notice that refunds would be problematic for the ISO, as evidenced by the November 1, 2000 transmittal letter for the Section 205 filing giving rise to this proceeding.

TANC's arguments are a reiteration of its arguments in pre-filed testimony and on briefs, which were carefully considered and rejected in the Initial Decision. *Id.*[12]

TANC focuses entirely on the ISO's estimate of 544 full-time employees – attaching dispositive significance to the number of *full-time employees* and apparently not realizing, as the Initial Decision did, that the estimate reflects an estimate of the *level of effort* needed to meet the ISO's workload in 2001. Tr. at 503:25 - 504:17; 99 FERC at 65,077. TANC's error is reflected in TANC's seemingly naïve argument that the ISO's labor estimate was not supported because the ISO did not state in its November filing that it might use contract labor in lieu of salaried employees. TANC BOE at 17. The assumption in TANC's argument is that the need for labor would disappear if full-time employees could not be found. In fact, as the Initial Decision found, that the ISO was unable to meet its workload with a particular type of employee does not render the ISO's estimate of staffing needed to meet the workload unreasonable.[13] Significantly, TANC has not challenged the reasonableness of the ISO's estimate of its workload for 2001, upon which the estimate of employees needed was based. *See* Tr. 503:22 – 504:17; Exh. ISO-23 at 14-15, 23, 25-27.[14] Nor did TANC dispute that the ISO's workload increased significantly in 2001 or present any evidence that the ISO could meet its workload more efficiently.

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12 TANC argues that the Initial Decision misconstrued TANC's arguments regarding the ISO's staffing level as limited to the effect on employee incentive compensation. TANC BOE at 16. While the Initial Decision begins its discussion of TANC's staffing level arguments with a discussion of incentive compensation, the Initial Decision goes on to address TANC's staffing arguments directly and on their merits. 99 FERC at 65,077-78.

13 To the contrary, TANC only argued that the proposed staffing level was too high because it represented an increase over the 2000 staffing level. TANC BOE at 16. TANC's argument does nothing to undermine the ISO's estimate of workload required to in a much higher stakes year. Moreover, the Initial Decision expressly noted TANC's argument regarding the significantly lower staffing level in 2000. 99 FERC at 65,077.

14 In fact, the ISO *under*-estimated its workload for 2001. *See* Exh. ISO-21 at 20:17 - 21:4.

The remainder of TANC's argument addresses the Initial Decision's finding that the ISO, in fact, required more costly contract employees. TANC argues, in essence, that the ISO should have presented evidence in addition to the testimony of the ISO's Treasurer, Philip Leiber. The Initial Decision found Mr.Leiber both knowledgeable and credible, and his testimony is sufficient evidentiary support; the Initial Decision, however, also found additional evidentiary support. Exh. ISO-19 at 10. TANC tosses out the argumentative chaff that the ISO did not submit with its filing any "ISO Governing Board directive to substitute contract employees for permanent employees." TANC BOE 18. TANC offers no explanation as to why such board action would be required. The Initial Decision recited the identical arguments that TANC now makes on the record, and found that:

> Mr. Leiber, the ISO Treasurer, and the individual most familiar with the relative costs of employees and contractors, testified credibly that "the budget was prepared with the assumption that more costly contracted resources would be converted to full-time ISO staff to save money."

99 FERC at 65,077, citing Exh. ISO-21 at 20:12-14, Exh. ISO-19 at 10.[15]

TANC's arguments were therefore fully considered by the Initial Decision, which – in light of the record evidence presented – found that the ISO's budget estimate of a labor need for 544 employees was just and reasonable. TANC offers no support for its argument that the Initial Decision erred in reaching its decision regarding the ISO's 2001 staffing estimate. TANC's argument should accordingly be rejected.

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[15] Contrary to TANC's suggestion, TANC BOE at 17, Mr. Leiber's testimony was highly probative (as found by the Initial Decision) and did address the ISO's reasoning at the time estimates for workload and employees were made.

4. The Initial Decision Properly Found That ISO's O&M Budget Should Not Be Reduced By The Amounts Discussed In ISO Management's November 9, 2000 Memorandum [Section I.A.1 of the Initial Decision]

TANC argues that the Initial Decision erred by casting this question in terms of a prudence review of the ISO's costs and therefore shifted the burden of proof to TANC. TANC BOE at 19-20. Whether this issue is one of "prudence" is irrelevant, because the Initial Decision determined the ISO had met its ultimate burden of proof. 99 FERC at 65,079. The Initial Decision reviewed at length the record evidence that established that the ISO had met its burden of proof in including these costs, and concluded:

> The record is clear that the Finance Committee and the Board 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., quoting Exh. ISO-21 at 22:4-7.

The Initial Decision expressly examined this issue under the "reasonable when made" standard, which TANC agrees is correct. TANC BOE at 20. The Initial Decision's reference to there being "no evidentiary basis for questioning the prudence of this judgement," 99 FERC at 65,079, was simply another way of saying that TANC had presented no evidence to overcome the ISO's extensive showing that its decision to incur these costs was prudent, *i.e.*, reasonable when made.[16] There is therefore no basis for TANC's exception, which should be rejected.

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[16] TANC inexplicably argues that "the ISO Board provided no basis for its failure to implement the cost reductions reflected in the referenced memorandum." TANC BOE at 21. In fact, as the Initial Decision noted, the Board decided against the reductions "because of the potential negative effects on ISO performance (in some cases affecting transmission-system reliability) from many of the reductions, and because severe problems had already appeared in the California markets and it was difficult to foresee the extent of additional demands that might be placed on the ISO in 2001." Initial Decision at 24, citing exhibits.

5. The Initial Decision Properly Found That The ISO's Forecasted Costs Associated With New Debt To Fund Capital Expenditures Were Just And Reasonable. [Section I.A.2 of the Initial Decision]

Only TANC alleges error in the Initial Decision's finding that the ISO's estimate of costs for the debt service on a bond issuance to fund the ISO's capital budget was just and reasonable. 99 FERC at 65,080.

TANC raises no new arguments in addition to those raised in its brief, TANC Br. 18-20, which were considered and rejected by the Initial Decision. *See* 99 FERC at 65,080. TANC continues to insist that because of notice periods and potential protest, the ISO would have filed under Section 204 of the FPA, 16 U.S.C. § 824c (2000), before the end of 2000 if it *really* had intended to issue bonds in the first quarter. TANC BOE 22-23. TANC insists that because the Initial Decision did not specifically address this presumption, it "erroneously concluded that it was appropriate to include these costs in the revenue requirement." *Id.* at 23.

The Initial Decision, however, found completely unpersuasive TANC's manufactured timeline of what the ISO knew and when it knew it. 99 FERC at 65,080. There was simply no reason to address, explicitly, TANC's speculations regarding the ISO's true intent based on a lack of a Section 204 filing by the end of 2000. TANC's speculation has no basis. The ISO could well have intended to file under Section 204 before the end of 2000 or shortly after the beginning of 2001, but delayed the filing when it learned its debt rating was under review, pending the outcome of that review. Moreover, preparation of a Section 204 filing does not take long, the notice period is only 20 days, and the ISO had no reason to anticipate protests TANC's estimation of the necessary lead time is thus simply unfounded.

While the reported Initial Decision is 125 pages in length, and deals in detail with the various positions raised by the parties, it could not specifically respond to each and every argument. The Initial Decision notes that "[a]ll arguments made by the participants, which have not been discussed and/or adopted by this decision have been considered and are rejected." 95 FERC at 65,197. TANC's assertion of "error" in the Initial Decision's failure to specifically address its conjecture that a Section 204 filing had to be made in December 2000 should, in light of its lack of evidence and logic, therefore be rejected.

TANC also reprises its argument – considered and rejected by the Initial Decision, 99 FERC at 65,080 – that the ISO's use of the debt service to fund capital projects directly was unsupported. TANC BOE at 23. That the post-rate filing downgrade of the ISO's debt in fact made issuance of new debt impossible says nothing about the reasonableness of having included this item at the time of budgeting and filing; thus it provides no basis for disallowance. Moreover, the budgeted amount was used to fund capital projects directly, on a "pay-as-you-go" basis. Exh. ISO-21 at 24:7-10. TANC's point that the revenue requirement filing did not include a proposal to, in effect, expense capital items is irrelevant. TANC BOE at 23. At the time of filing, the intent – reasonable at the time – was to fund capital projects through new debt, so there would have been no reason to propose expensing them.

Finally, TANC characterizes as a "bare unsupported post hoc explanation" Mr. Leiber's statement that funds earmarked for new debt would be spent on capital projects, and also suggests that the ISO should be required to identify the projects on which the funds were spent. TANC BOE at 23. Both of TANC's positions are nonsensical. A sworn statement by the ISO's Treasurer as to the manner in which specific funds will be spent is certainly more than an "unsupported" assertion – it is a fact, undisputed by any party. Indeed, Mr. Leiber testified at length on this subject, far beyond a simple statement that the funds would be spent to expense capital projects. *See* Exh. ISO-21 at 23:21 – 26:19. There simply is no requirement that the ISO identify specific capital projects on which the funds will be spent.[17] The Initial Decision recited and considered this argument, found it unpersuasive, and rejected it. 99 FERC at 65,079-80. TANC has not shown any way in which the Initial Decision erred rejecting its arguments on this issue.

B. The Initial Decision Properly Found That The ISO's GMC Structure Of Three Service Categories Is Just And Reasonable [Section I.B of the Initial Decision]

MID is the only party opposing the Initial Decision's finding that the GMC's structure of three service categories is just and reasonable. The crux of MID's exception to the Initial Decision's finding is that 1) the ISO's three-service-category rate structure is unjust and unreasonable, 2) that by relying on future events, the Initial Decision did not require the ISO to meet its burden of proof, and 3) the Initial Decision should have replaced the ISO's proposal with MID's own proposal developed by Lawrence Kirsch. MID BOE at 8-9.

Contrary to MID's argument that the Initial Decision "emphasizes" that the ISO's proposal is "imperfect," MID BOE at 8, the Initial Decision rather recites:

> Cost causation principles require only that rates match costs to serve classes of customers and individual customers "as closely as practicable," not that they do so perfectly. *See Alabama Elec. Coop., Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982).

99 FERC at 65,086. The Initial Decision notes that while the ISO's proposal is not "perfect," it is just and reasonable. *Id.* The Initial Decision's language serves to emphasize, not the

[17] Nonetheless, the projects are largely identifiable from the record. Mr. Leiber noted that due to the inability to issue debt the ISO was reducing capital spending from the budgeted $37.7 million to $23 million, mainly through deferral of the Comprehensive Market Reform/Congestion Management Reform efforts. Exh. ISO-21 at 24:16-18; 25:2-4. From the table of budgeted capital for 2001, Exh. ISO-18 at 42, one can readily deduce where the amount budgeted for new debt service (along with a portion of the operating reserve, *see* Exh. ISO-21 at 25:11-15) was spent.

perfection or imperfection of the ISO's rate, but rather the legal standard that a rate need not be perfect, but only reasonable.[18]

MID asserts that the ISO has not met its burden of proof in establishing the reasonableness of the GMC's three-service-category structure, and that the design of the GMC was a "token effort" that will "encourage further poorly supported filings in the future." MID BOE at 9. MID's assertions are completely belied by the record. The record is dense with testimony concerning the development of the ISO's GMC rate structure, and establishes that the GMC's design was a lengthy and comprehensive process. *See* 99 FERC at 65,083-84. 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 further analysis, the ISO settled on three – Control Area Services ("CAS"), Market Operations

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18 *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. 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.").

("MO"), and Inter-Zonal Scheduling[19] – 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 16:22-17:2. The Joint Audit/Finance Committee and the full stakeholder Board approved the three service categories. *Id.* at 11:4-10.

MID's allegations that the ISO has not supported the GMC's structure on the record or met its burden of proof with regard to the reasonableness of the rate is thus clearly unsupported.

MID also argues that the Initial Decision only found the ISO proposal to be just and reasonable because it was the "last proposal standing" rather than it being just and reasonable on its own merits. MID BOE at 9. This is simply not accurate. The Initial Decision clearly finds that the ISO's rate design involving three service categories *is* just and reasonable – not when compared to less developed proposals, but on its own merits. 99 FERC at 65,090.

Even if the ISO's proposal had not been found to be just and reasonable, however, the Initial Decision would have still rejected the proposal put forward by Dr. Kirsch on behalf of MID. The Initial Decision notes with approval Staff's lengthy recitation of deficiencies with the Kirsch proposal and concludes:

> The record fully supports Staff's position that Dr. Kirsch's proposal lacks sufficient clarity for implementation, lacks sufficient information for market participants to de-

[19] 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.

> termine cost responsibility, lacks sufficient information for market participants to determine how much it will cost to implement, and may very well be inconsistent with Commission policy as currently presented.

Id. (footnote omitted).

The Initial Decision does adopt the ISO's suggestion to have this proposal – in a more fully developed form – re-introduced in the 2003 stakeholder re-evaluation process. *Id.* MID interprets the Initial Decision's suggestion as evidence that the Initial Decision is putting off the implementation of a just and reasonable structure in the hopes that one might be developed during the 2003 re-evaluation process. MID BOE at 9. Again, in its allegation of error, MID chooses to ignore the extensive review of the GMC structure by the Initial Decision at pages 65,083 through 65,090 and the Initial Decision's conclusion in light of that review that the GMC structure *as currently proposed is just and reasonable.* 99 FERC at 65,090.

MID's Brief on Exceptions proceeds with a number of permutations of the argument that the Initial Decision failed to take into account that different Loads benefit from CAS to different degrees. MID BOE at 13-18. MID suggests that the Initial Decision's analogy to incurance fails because vertically integrated entities "self-insure" in part and involve risks that differ from other Loads. MID BOE at 14-15. MID also argues that different Market Participants need different amounts of ISO-procured resources and impose differing burdens than other Market Participants. MID BOE at 15-18.[20] This is a variation on the arguments for "net" load billing instead of "gross" load billing, and much of the discussion in Sections G and H of this Brief is applicable in response to MID's argument as well. As discussed there, the ISO has to plan and otherwise be prepared to accommodate transmission flows and energy imbalances caused by *all* Load in the Control Area, not just the Load that most often causes flows and imbalances, and therefore *all* load both causes CAS costs and benefits from

CAS to some extent. As the Initial Decision pointed out, Market Participants who use more of the ISO's services than others do pay more of the ISO's Grid Management Charge: under the IZS bucket, which includes the ISO's costs of administering congestion management, the firm transmission right ("FTR") auction, FTR monitoring, and FTR secondary market monitoring and scheduling, where the billing determinants are equal to the absolute value of the net scheduled intra-zonal flow (excluding existing transmission customers) per path for a given Scheduling Coordinator; and, under the MO bucket, which includes the ISO's costs of market- and settlement-related services (e.g., the cost of operating an Ancillary Service market as well as the cost of billing), where the billing determinants are equal to a given Scheduling Coordinator's total purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy. 99 FERC at 65,085-86. In addition, Market Participants may avoid other charges by reducing reliance on the ISO. For example, entities that self-provide reserves will avoid the costs of those reserves. *See* Exh. J-8 at § 2.5.20.2. As the Initial Decision found, however, the Control Area Services are caused by and provided for the benefit of all load utilizing the grid. *Id.*

The Initial Decision recognized that, while the CAS category may well be refined later into more "granulated" service categories, or analyses may be done to support charging less than the full CAS rate to some load, *at this stage of the unbundling process* charging CAS to all load equally is not unreasonable; it was not *practicable* to refine CAS charges further. *Id.* Cost causation principles require only that rates match costs to serve classes of customers and individual customers "as closely as practicable," not that they do so perfectly. *Id.*; *see Alabama Elec. Coop., Inc. v. FERC,* 684 F.2d 20, 27 (D.C. Cir. 1982). In sum,

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[20] CCC makes similar arguments. *See* CCC BOE at 21-22, 23.24.

MID's arguments alleging error in the Initial Decision's adoption of the ISO's rate design are unsupported and should be rejected.

C. The Initial Decision Properly Found That If Changes To The Service Categories Are Ordered, Such Changes Should Be Prospective Only [Section I.B.2 of the Initial Decision]

The Initial Decision did not order any changes to the ISO's rate structure. It did conclude, however, that if changes were ordered by the Commission, such changes should be prospective only. 99 FERC at 65,091. MID is the only party opposing the Initial Decision's conclusion. MID BOE at 19.

If the Commission 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,[21] and in the case of the non-profit ISO, it is essential. Retrospective application would leave the ISO vulnerable to underrecovery. 99 FERC at 65,194; *see generally*, Exh. ISO-21 at 50-53. 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 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. MID's argument for retroactive implementation of any changes disregards the impacts of such a decision and presents arguments that are contrary to the Commission's precedent. MID BOE at 19.

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[21] 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 charge others more than they had paid under the original rate design. *Second Taxing District of the City of Norwalk v. FERC,* 683 F.2d 477 at 490 (D.C. Cir. 1982); *Commonwealth Edison Co.*, 8 FERC ¶ 61,277 (1979).

In addition, MID has failed to demonstrate any error by the Initial Decision in applying the Commission's precedent. For these reasons, MID's exception to the Initial Decision's recommendation on this issue should be rejected.

If retroactive charges are ordered, however, the ISO renews its request that surcharge authority should be granted to ensure that the ISO does not under-recover its costs. *See* 2001 GMC November 1, 2000 Transmittal Letter at 11.

D. The Initial Decision Properly Found That The ISO's Cost Allocations Were Just And Reasonable [Section I.C of the Initial Decision]

TANC excepts to the Initial Decision's determination that the ISO's cost allocations are just and reasonable. TANC BOE at 32.

1. The Initial Decision Properly Found That, Based On The Record Evidence, The ISO's Cost Allocations Are Currently Just And Reasonable

TANC argues that the Initial Decision errs by relying on future changes to approve the ISO's 2001 allocations. *Id.* This assertion is belied, however, by the language of the Initial Decision. The Initial Decision notes that the ISO has adequately supported its allocation of costs in the present. The Initial Decision states:

> I am persuaded that the record establishes no compelling basis for a change to the ISO's 2001 GMC allocations. ... The documentation presented by the ISO, Exh. ISO-9 and Exh. ISO-18, provides adequate support, as explained by Witness Leiber's testimony (Exh. ISO-7 at 4-20; Exh. ISO-16 at 10; Exh. ISO-21 at 31-33), to demonstrate that the ISO's allocations are just and reasonable *for the present stage of unbundling*.

99 FERC at 65,093 (emphasis in original). The Initial Decision thus finds that the ISO's allocations are just and reasonable based on the current GMC structure. It goes without saying that if the service categories were further unbundled, the allocations that would accompany such additional unbundling would have to be reviewed by the Commission. The Initial Deci-

sion also makes clear that the ISO's Cost Allocation Matrix is a just and reasonable means of allocating the ISO's costs. The Initial Decision states:

> It is my determination that the ISO's analytical support documentation and CAM, Exh. ISO-9, updated for 2001 by Exh. ISO-18, (Exh. ISO-21 at 35:19 – 16:18), and supplemented by Mr. Leiber's testimony, (Exh. ISO-7 at 4:12 – 20:17: ISO-16 at 10:3 – 10, ISO-21 at 31:15 – 33:18), demonstrate that the ISO's Cost Allocation Matrix provides a reasonable basis for allocating costs for the present stage of unbundling.

Id.

TANC's contention that the Initial Decision errs by deferring a finding on the justness and reasonableness of the current ISO allocations in favor of future proceedings is completely unsupported and should be rejected.

2. The Initial Decision Properly Found That The ISO's Use Of Headcount In 2001 Was Just And Reasonable

TANC is the only party that takes exception to the Initial Decision's finding that the ISO's use of a head count method was just and reasonable for the allocation of some costs. TANC BOE at 34.

TANC contends that the ISO's allocation is unjust and unreasonable because it uses headcount as an allocator in some instances and relies on the judgment of managers. TANC BOE at 34-36. The ISO's Treasurer, Mr. Leiber, testified that the ISO has used a labor cost analysis, not headcount, in allocating the GMC for 2002. Tr. at 279:12-16. Thus, TANC's concern with headcount as an allocator is not an ongoing issue. While TANC insists that the ISO's move to a labor cost analysis in 2002 is an admission that its 2001 methodology was flawed, this is not the case. TANC BOE at 34. The ISO moved to a labor cost analysis *not* because it thought allocations using headcount were flawed, as TANC suggests, but as part of the continuing evolution and refinement of the unbundling process. Exh. ISO-21 at 44:23 –

45:2; Tr. 280:5-10. Use of headcount for 2001 was properly supported in the 2001 filing and was just and reasonable.

At page 32 of its BOE, TANC takes a quotation from the Initial Decision out of context and, moreover, provides only a partial quotation. TANC uses that partial quote to create the erroneous impression that the Initial Decision did not find that the use of headcount in 2001 was just and reasonable, an implication rebutted by the unquoted portion of the paragraph. The entire quotation reads as follows:

> While TANC Witness Cohen's recommendations may improve the process, *they do not show the ISO's approach to be unreasonable at this time*. The documentation presented by the ISO, Exh. ISO-9 and Exh. ISO-18, provides adequate support, as explained by Witness Leiber's testimony (Exh. ISO-7 at 4-20; Exh. ISO-16 at 10; Exh. ISO-21 at 31-33), to demonstrate that the ISO's allocations are just and reasonable *for the present stage of unbundling*.

99 FERC at 65,093 (emphasis added).

TANC's concern that headcount does not reflect the late-2000 ISO reorganization, BOE at 35, is irrelevant; a labor cost analysis would not have reflected the reorganization, either. The concern that using headcount produces skewed results because of differences in ISO salaries, TANC BOE at 35, is misplaced; Mr. Leiber testified that he prepared a labor cost analysis for the 2001 budget as a check on the headcount method (and produced it to TANC in discovery), which showed that the two methods yielded virtually identical results. Tr. 280:5-10. TANC attempts to characterize the ISO labor study as "unreliable," stating that it is not in the record. TANC BOE 39-40. The Presiding ALJ need not have the actual study before her to determine that the record testimony evidence of a witness is credible and reliable. The Presiding Judge certainly can judge the credibility of a witness and determine the proper weight to give to his or her testimony. The Presiding Judge can also take into account the fact that the labor cost analysis underlying the witness's testimony was provided to TANC through discovery, and yet TANC itself did not cross-examine Mr. Leiber on it. TANC's arguments are therefore unsupported and should be rejected.

Finally, the Commission has approved the use of headcount as a methodology. *See* 99 FERC at 65,093 (citing *California Power Exchange Corporation*, 89 FERC ¶ 61,279, at 61,905-06 (1999). TANC attempts to distinguish *Power Exchange* from the ISO's use of headcount by arguing that headcount was acceptable in that case only because the groups of employees involved were performing similar tasks. TANC BOE at 35. But the problem with TANC's unsupported assertion that different service categories will lead to inequitable allocation in the instant case is the same addressed by the Commission ruling in the *Power Exchange* case. In that case, the Commission stated:

> In any event, we have not been presented with any basis to conclude that CalPX and CTS would have any different mix of employees given that they are each involved in the same basic activity, *i.e.*, operating an electricity market.

89 FERC at 61,906.

Similarly, while TANC has submitted testimony supporting the obvious -- that "ISO employees do not all have the same salary," TANC BOE at 35 -- TANC has presented no evidence in the instant case that headcount as applied in the GMC would be spread amongst a different "mix" of these differently paid employees. TANC's attempted distinction of the *Power Exchange* case simply does not hold up.

TANC's arguments fail to demonstrate that the Initial Decision erred in law or fact in finding that the ISO's use of headcount in 2001 was just and reasonable, and should be rejected.

3. The Initial Decision Properly Found That The ISO's Allocation Of Cost Center 1424 Was Just And Reasonable [Section I.C.2 of the Initial Decision]

TANC excepts to the Initial Decision's rejection of the allocation process proposed by TANC for Cost Center 1424 "Information Technology Assets, Contracts and Change Management." TANC BOE at 36. The Initial Decision found that *all* of the ISO's allocations were just and reasonable. 99 FERC at 65,093. Direct assignment of Cost Center 1424, 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. TANC's argument that "only by chance" might employees' time be allocated correctly is baseless. TANC BOE at 37. The ISO, however, has utilized the judgment of the management most familiar with various ISO operations. ISO managers and directors, guided by task-specific allocation aids developed by Mr. Leiber's project team, assigned budgeted costs to the service categories. Exh. ISO-7 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. The scenario presented by TANC, of costs being assigned at random and with no basis in cost causation, is completely hypothetical, and bears no relation to what actually happened at the ISO. TANC's challenge to the Initial Decision's conclusion with respect to the allocation of Cost Center 1424 should be rejected.

Because the current proposal was found to be just and reasonable, 99 FERC at 65,093, TANC's argument that not altering the ISO's allocation of this cost center will leave an unreasonable allocation in place, TANC BOE at 37, is without merit or support and should be rejected.

4. The Initial Decision Properly Found That The ISO's Allocation Of MCI Contract Costs Was Just And Reasonable [Section I.C.3 of Initial Decision]

TANC is the only party that challenges the Initial Decision's treatment of the ISO's MCI contract cost allocation. TANC BOE at 37. The basis of TANC's allegation of error is the contention that in finding that the MCI contract allocation is to be revisited the appropriate forum is the 2003 reevaluation, the Initial Decision has left an unjust and unreasonable rate in place. TANC BOE at 37-38. TANC's allegation of error is unsupported. The Initial Decision found that *all* of the ISO's allocations were just and reasonable, 99 FERC at 65,093, including the MCI contract cost, on the basis of the record evidence reviewed briefly below.

TANC's view continues to be that the ISO should directly assign the costs of the MCI contract to the three GMC categories. For example, TANC argues that to the "extent that these costs were incurred for reasons related to markets, they should be allocated to Market Operations and not [CAS]." TANC BOE at 39. TANC is well aware that MCI has not provided the ISO with the data necessary to make such a direct allocation of costs. Exh. ISO-21 at 49:10-15. Efforts by the ISO employees most knowledgeable about this contract have also failed to arrive at any approach to assigning the MCI contract costs superior to that used in the filing. Exh. ISO-21 at 47:2-8.

Absent the information needed to directly assign the ISO's MCI contract costs, several of the ISO's telecommunications experts devoted attention to the issue of how best to assign these costs. *Id.* The ISO used a modified headcount method, with a portion of the costs assigned using total ISO headcount, another portion using the headcount of the departments that use the MCI network significantly, and a third portion assigned directly to Market

Operations. *Id.* at 47:11-19. The care with which the ISO approached the assignment based on the information available to it indicates that it gave appropriate attention to this important cost center. The cost center is used by all segments of the ISO and it under-girds the entire ISO operations – not just Market Operations. *Id.* at 48:7 – 49:8.

TANC has done no more in its challenge to the Initial Decision on this issue than to restate its arguments previously considered and rejected on their merits in light of the record evidence. TANC has demonstrated no legal or factual error. TANC's allegations of error should accordingly be rejected.

E. The Initial Decision Properly Found That If Changes To The ISO Allocations Are Ordered, Such Changes Should Be Prospective Only [Section I.C.4 of the Initial Decision]

While the Initial Decision finds that the ISO's allocations are just and reasonable, 99 FERC at 65,093, and that no changes should be made to the ISO's allocations, *Id.* at 65,096, the Initial Decision also concludes that if changes are ordered, they should be ordered on a prospective basis only. *See id.* at 65,092-93. TANC is the only party that challenges this conclusion. TANC BOE at 41.

The basic premise of TANC's argument – that cost allocation is not a matter of rate design, TANC BOE at 41-43 – is invalid. The manner in which the ISO's costs are allocated to the service charges – through the ISO's cost allocation matrix – determines the percentage of the ISO's costs that will be charged to each of the three service categories and therefore is a basic element of the ISO's rate design. The ISO's cost allocation matrix is an integral component of the ISO's rate design and a change in it would result in a change in the relative portions of the ISO's revenue requirement that would be charged to each of the three service categories. TANC's contention that the Initial Decision erred in ordering that any changes to the ISO's rate allocation formulas should be made on a prospective basis should be rejected.

For reasons similar to those stated under Section VI.C., above, the Initial Decision correctly found that any changes to the ISO's 2001 cost allocation formulas should be made prospectively.

If retroactive charges are ordered, however, the ISO's renews its request that surcharge authority should be granted to ensure that the ISO does not under-recover its costs. *See* 2001 GMC November 1, 2000 Transmittal Letter at 11.

F. The Initial Decision Properly Found That The Assessment Of The Control Area Services Charge Based On Control Area Gross Load Is Just And Reasonable [Section I.E of the Initial Decision]

The exceptions to the Initial Decision's conclusion that the allocation of CAS charges to behind-the-meter Load is just and reasonable fall into the same categories that the Initial Decision identifies in discussing this issue: that such allocation is inconsistent with the Commission's order on Amendment No. 2 to the ISO Tariff, *California Independent System Operator Corp.*, 82 FERC ¶ 61,312 (1998); that the Initial Decision has violated or misapplied cost-causation principles; and that the ISO's proposed allocation violates contractual agreements.

1. The Initial Decision's Conclusion That The Commission's Order On Amendment No. 2 Does Not Foreclose The Proposed Allocation Of CAS Charges Is Reasonable And Supported By The Evidence

The Initial Decision rejected arguments that the Commission's Order on Amendment No. 2 to the ISO Tariff barred the allocation of CAS to Loads that are not served over the ISO Controlled Grid. In their Briefs on Exceptions, various parties reassert these arguments.

SMUD and TANC argue that, in light of the Commission's decision on Amendment No. 2, the allocation of CAS charges to Load that is not served over the ISO Controlled Grid must be rejected because it is contrary to the ISO Tariff.[22] SMUD BOE at 12-24, TANC BOE at 24-30. They contend that the Commission's decision limited the ISO's authority to the ISO Controlled Grid. *Id.* TANC simply asserts that the ISO's proposed allocation of CAS therefore violates the filed rate doctrine. TANC BOE at 24. SMUD's variation of the argument is that the CAS charge cannot apply to non-ISO Controlled Grid transactions without a change to the existing definition of the ISO Controlled Grid. SMUD BOE at 24.

TANC first asserts that the Initial Decision failed to recognize or include its argument, TANC BOE at 25, and then incorrectly concludes that the Initial Decision failed to consider it. Regardless of the accuracy of TANC's premise, the Initial Decision did explicitly identify SMUD's virtually identical argument, and therefore did evaluate TANC's reasoning. 99 FERC at 65,101. The Initial Decision notes that the Initial Decision considered and rejected all arguments that were not explicitly rejected in the Initial Decision; accordingly, the Initial Decision did not find TANC's and SMUD's tariff argument sound. *Id.* at 65,197.

The Initial Decision's rejection of these tariff arguments is dictated by simple logic. This proceeding concerns a tariff *amendment.* The amendment provides the necessary authority, regardless of the current language and definitions in the ISO Tariff. The ISO's proposed allocation, absent the amendment, would be of course contrary to the ISO Tariff;

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22 SDG&E and TANC also cite the Arbitrator's decision in *Pacific Gas & Electric Company v. California Independent System Operator Corporation*, Case No. 711980071100 (December 13, 2001) for a similar proposition. SDG&E BOE at 24 n.25; TANC BOE at 30. The Presiding Judge has ruled that this decision is irrelevant and will not be considered. Neither SMUD nor TANC appealed or took exception to that ruling, but nonetheless make the same arguments. As the Commission has recognized, the Arbitration, which is under appeal in Docket No. EL02-45, involves only the costs of Ancillary Services – which are not involved in this case. *California Independent System Operator Corp.*, 95 FERC ¶ 61,047 (2002). Moreover, the ISO does not assert that the ISO Tariff, prior to the GMC filing, authorized the ISO to charge the GMC to in connection with transactions that did not use the ISO Controlled Grid. The GMC filing, if approved by the Commission, explicitly provides that authority, notwithstanding anything in the arbitration award, even if that award is affirmed by the Commission.

otherwise, there would be no reason to file the amendment. If the Commission approves the amendment, the allocation will not be contrary to the ISO Tariff. Nothing in the Commission's order on Amendment No. 2 prohibits the ISO from seeking further amendments regarding the GMC.

TANC also contends that the Commission's order on Amendment No. 2 prevented the ISO from providing services related to transactions that do not occur on the ISO Controlled Grid and that the ISO's proposal violates the filed rate doctrine for that reason. TANC BOE at 27-29. SMUD and SDG&E similarly argue that the Amendment No. 2 order refused to allow the ISO to allocate GMC to Load that is not served over the ISO Controlled Grid; they contend that there is no reason to modify that precedent. SMUD BOE at 21-24; SDGE BOE at 23-25. The Initial Decision recognized that such arguments distort the Commission's order and rewrite history and cited the Commission's *explicit* reservation of the GMC issue:

> We also note that the issue of whether the GMC should apply to entities that deliver energy over facilities that are not part of the ISO Controlled Grid, but which are within the ISO Control Area, is within the scope of the proceeding in Docket No. ER98-211-000, *et al.*

California Ind. System. Oper. Corp., 82 FERC ¶ 61,312 at 62,241 (1998). 99 FERC at 65,108-109.[23] If, as TANC, SMUD, and SDG&E contend, the Commission's decision pre-

[23] The Initial Decision's interpretation is fully consistent with the remainder of the order on Amendment No. 2. The Commission noted that the requirement that all Load in the Control Area be scheduled would result in allocation of the GMC to those Loads. In rejecting Amendment No. 2, however, the Commission did not address the issue of financial responsibility for those services that the ISO must, as Control Area operator, perform or conclude that such financial responsibility would be inappropriate. Rather, its rejection of Amendment No. 2 was based exclusively on operational issues and burdens place on the Participating Transmission Owners:

> [W]e find that these changes are unjust and unreasonable because they would broadly expand ISO control over non-jurisdictional facilities which are not being transferred to the ISO's control. As drafted, proposed Amendment No. 2 is also inconsistent with our prior orders and would improperly impose additional obligations on Participating Transmission Owners. We also share intervenor concerns about the lack of time to determine the full impact of Amendment No. 2 at this late date. Because of these problems, we do not consider acceptance of the proposed Amendment No. 2 subject to

cluded such an allocation of the charges, there would have been no reason to reserve the issue. The Commission's specific decision not to rule on the GMC demonstrates that its order cannot be read to preclude the allocation of GMC on all load within the Control Area.

Attempting to avoid this roadblock to its argument, SDG&E asserts that the Commission did not reserve the GMC issue, but was giving "guidance" to its resolution in Docket No. ER98-211-000. SDG&E BOE at 24-25. Of course, if the Commission were resolving the issue, as SDG&E argues, "guidance" would not be necessary; the Commission would simply have noted that the matter is no longer at issue. SDG&E's reading not only distorts the plain meaning of the Commission's statement, but – as the ISO pointed out in its Reply Brief but SDG&E fails to address – it also ignores subsequent Commission action in this regard. On March 31, 1998 – four days after the Amendment No. 2 order that SDG&E asserts resolved the GMC issue – the Commission issued an order clarifying the scope of Docket No. ER98-211-000. The Commission stated, again *explicitly*:

> We hereby clarify that the scope of the hearing established in the December 17 order includes the issue of whether the GMC should apply to all loads in the ISO control area, or only to the loads served by the ISO Controlled Grid.

California Ind. Sys. Oper. Corp., 82 FERC ¶ 61,348 at 62,357 (1997). Obviously, the Commission did not consider the issue resolved. TANC's, SDG&E's and SMUD's lengthy dissertations about the nature of Amendment No. 2 and the Commission's order are thus beside the point.

Further, as the ISO noted in its Reply Brief, more recent orders confirm that the Commission does not view its rejection of Amendment No. 2 as controlling on questions of

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> the outcome of a hearing to be a viable option. Moreover, we are persuaded by the arguments that the proposed changes contained in Amendment No. 2 are not necessary for ISO operations.

82 FERC at 62,241.

the ISO's authority to assess charges in connection with Control Area transactions that do not use the ISO Controlled Grid. For example, the Commission has required the ISO to submit tariff amendments to require that all Generators in the ISO Control Area offer their available Generation to the ISO, regardless of whether the Generator is a Participating Generator or its Generating Unit is directly connected to the ISO Controlled Grid. *San Diego Gas and Elec. Co. v. Sellers of Energy and Ancillary Serv.*, 95 FERC ¶ 61,115 at 61,355-56 (2001). More recently, the Commission approved a billing determinant of Control Area Gross Load for emissions and start-up costs incurred by Generators dispatched under the must-offer obligation. *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Serv.*, 97 FERC ¶ 61, 293 (2001). Apparently the Commission does not read its order on Amendment No. 2 in the same manner as the parties making these arguments.

2. The Initial Decision Has Properly Applied Cost Causation Principles

The Initial Decision examines both the causes for the ISO's incurrence of CAS costs and the benefits that entities receive because of the ISO's incurrence of those costs. 99 FERC at 65,109-111. SMUD, TANC, MID, CAC, CCC, and Industrial Associations contend that the Initial Decision's examination of benefits received is inconsistent with cost-causation principles.[24] CAC BOE at 38-43; CCC BOE at 9-20; IA BOE at 6-18; MID BOE at 13-18; SMUD BOE at 24-42; TANC BOE at 29. To the contrary, the analysis of benefits received can be part and parcel of the evaluation of cost causation, and the Initial Decision's analysis is fully consistent with Commission precedent.

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[24] MID's primary discussion of cost causation focuses on its assertion that the Initial Decision does not take into account the varying contributions of entities to the need for CAS. MID BOE at 13-18. CCC makes similar arguments. CCC BOE at 21-22, 23-24. These are largely arguments for additional buckets, and is addressed above in Section B. CCC also contends that the Initial Decision ignores the benefits that on-site Gen-

The Initial Decision relied upon *Midwest Independent System Operator, Inc.*, 98 FERC ¶ 61,141 (2002) ("MISO Rehearing Order"), in concluding that it is appropriate to consider "benefits received" in allocating the CAS charges. SMUD contends that this reliance that the MISO Rehearing Order "stands for the proposition that ISO charges will apply only to the gross load of *users* of the grid." SMUD BOE at 28 (emphasis in original). As an initial matter, even if SMUD's characterization is correct, it does not change the fact that the Commission specifically relied upon *benefits received.* SMUD's characterization, moreover, is incorrect. The situation that the Commission addressed in the MISO Rehearing Order is quite analogous to the circumstances presented by SMUD. Certain utilities had protested the inclusion of bundled loads in the calculation of a cost adder because those loads were served by Generation located on the distribution systems, and therefore *did not use the facilities controlled by the Midwest ISO.* The Commission concluded:

> Intervenors fail to consider the benefits all users *of the regional grid* will receive when that grid is operated and planned by a single regional entity instead of multiple local entities whose goals may often conflict. As a result of this move to unified planning and operation of the regional grid, we expect to see more efficient siting of transmission facilities from the regional perspective; *i.e.*, siting that follows need rather than arbitrary boundaries such as individual local service territories. This will result in enhanced reliability which will benefit all loads. This is because *the non-Midwest ISO-operated facilities*, such as those connected to local generation, in this region are integrated with the facilities operated by the Midwest ISO. It is established Commission policy that an "integrated transmission grid is a cohesive network moving electricity in bulk." Thus all customers using that grid share in all costs of the grid, because they all benefit. This policy has been affirmed in court. Thus, load served from generation located on an individual transmission owner's system (i.e., located on low-voltage transmission facilities *that have not been transferred to Midwest ISO*) can not be served reliably without the facilities operated by Midwest ISO. If those Midwest ISO-operated facilities were to disappear, service to all loads, including bundled retail loads, would suffer greatly.

eration provides. CCC BOE at 20. The benefits that CCC cites, however, are provided by all Generation. There is no reason to credit Load served by on-site Generation for those benefits, but not other Load.

98 FERC at 61,412 (footnotes omitted)(emphasis added).

SMUD correctly notes that the Commission clarified that it "did not provide that bundled retail customers and grandfathered agreement customers should be directly assessed the Cost Adder." SMUD BOE at 30, quoting 98 FERC at 61,413. The Commission clarification, however, was only dealing with the question of direct billing – not cost allocation. The ISO did not propose to directly bill Governmental Entities ("GEs") or Qualifying Facilities ("QFs") for CAS, but rather to bill Scheduling Coordinators. The ability to pass those costs through would be determined separately by the Commission (GEs) and the CPUC (QFs). The Initial Decision determined, instead, that the ISO should directly bill those entities. 99 FERC at 65,110-111. Whether the Commission upholds that portion of the decision on billing is completely independent of the propriety of allocating costs according to those that benefit from the ISO's CAS.

SMUD is also correct that the *MISO Rehearing Order* stated that "all load relying upon facilities under the Midwest ISO's control be placed and provided under the Midwest ISO Tariff so that the Midwest ISO will . . . be the only provider of transmission service over the facilities under its control." SMUD BOE at 30, quoting 98 FERC at 61,413. SMUD infers from this statement that the order was directed only at Midwest ISO grid loads of Midwest ISO Participants. This inference that the order is confined to Midwest ISO grid loads is directly contradicted by the language quoted above, which explicitly refers to "facilities that have not been transferred to Midwest ISO." Although the Commission was indeed only referring to Midwest ISO Participants, the application of tariff provisions to those participants were the only matters before the Commission. That fact does not diminish the Commission's conclusion that the *benefits received* by loads served through *non-grid facilities* justified the allocation of costs to those loads.

SMUD, TANC, CAC/EPUC, Industrial Associations, and CCC also argue more generally that the allocation of costs according to benefits received is inconsistent with cost-causation principles. SMUD BOE at 37-40; TANC BOE at 29-30; CAC/EPUC BOE at 38-43; CCC BOE at 9-20; IA BOE at 7-18. As the ISO pointed out in its Reply Brief, however, evaluation of benefits can be merely the flip-side of the evaluation of causation. For example, if an interconnection request requires transmission system upgrades that benefit all users of the grid, the Commission generally requires that the costs be assigned to all users of the Grid, not just to the entity requesting the interconnection. *See, e.g., Western Mass. Elec. Co.*, 66 FERC ¶ 61,167 (1994), *aff'd sub nom, Western Mass. Elec. Co. v. FERC*, 165 F.3d 922 (D.C. Cir. 1999). Citing *Western Massachusetts* for the proposition that "*[e]ven if a customer can be said to have caused the addition of a grid facility*, the addition represents a system expansion used by and benefiting all users due to the integrated nature of the grid," the Commission has explicitly noted, "[t]his treatment does not violate cost causation principles." *Removing Obstacles to Increased Electric Generation And Natural Gas Supply In The Western United States*, 96 FERC ¶ 61,155 at 61,674 (2001) (emphasis added). Similarly, the Commission approved the assignment of costs for the ISO's 2001 Summer Demand Relief Program to Scheduling Coordinators according to metered Demand (and exports), despite protests from entities including TANC, SVP, and MID that pro rata assignment of costs is improper since it assigns costs to entities that did not cause the costs to be incurred. The Commission concluded, "[T]he costs of the Summer 2001 Program are properly allocated on a system-wide basis to all Scheduling Coordinators because the Demand Relief Program benefits all parties by providing a means to maintain grid reliability." *California Ind. Sys. Oper. Corp.*, 97 FERC ¶ 61,149 at 61,648 (2001).

Various parties cite *KN Energy, Inc. v. FERC*, 968 F.2d 1295 (D.C. Cir. 1992), for the principle of cost causation and for the proposition that departures from that principle, such as the "cost-sharing" and "value of service" principles, are only appropriate in extraordinary circumstances, CAC BOE at 39-40, 42; CCC BOE at 10, 15-18; IA BOE at 8-10; TANC BOE at 29, which the Commission has concluded do not exist, CAC BOE at 40-41; IA BOE at 9-10.[25]

The arguments improperly conflate the "value of service" allocation discussed in *KN Energy* with the type of benefits analysis included in the Initial Decision. FERC's "value of service" allocation that the Court approved in *KN Energy* involved very general benefits: costs attributable to past arrangements (take or pay contracts) that interfered with restructuring were allocated to entities that did not cause those arrangements on the basis that the entire industry benefited from restructuring. 968 F.2d at 1300-01. The Initial Decision allocates to behind-the-meter Loads the costs of services that the ISO *contemporaneously* provides to all interconnected Load in the Control Area and from which the behind-the-meter Loads *contemporaneously* benefit. This analysis is more closely related to the cost causation principle that "[p]roperly designed rates should produce revenues from each class of customers which

[25] As part of their support for this proposition, CAC/EPUC and Industrial Associations cite to *Transmission Access Policy Study Group v. FERC*, which case remanded in part and otherwise affirmed the Commission's Order Nos. 888 and 888-A, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs., Regs. Preambles Jan. 1991-June 1996 ¶ 31,036 (1996), at 31,798, 31,800-801 ("Order No. 888"), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs., Regs. Preambles July 1997-Dec. 2000 ¶ 31,048 (1997), at 30,380 ("Order No. 888-A"), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *remanded in part and otherwise aff'd sub nom. Transmission Access Policy Study Group, et al. v. FERC*, 225 F.3d 667, 706, 707 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 122 S. Ct. 1012 (2002).

match, as closely as practicable, the costs to serve each class or individual customer," 968 F.2d at 1300 (quoting *Alabama Electric Cooperative, Inc. v. FERC*, 684 F.2d 20, 27 (D.C.Cir.1982)), than to the "value of service" principle discussed in *KN Energy*. Even with regard to the "value of service" principle, however, the *KN Energy* Court noted:

> the benefit principle may simply prove to be another prism through which to view the question of cost causation -- one that admittedly extends the chain of causation further than FERC has done traditionally. That is, rather than focusing us on the most immediate and proximate cause of the cost incurred, the benefit principle may only ask us to look at a host of contributing causes for the cost incurred (as ascertained by a review of those who benefit from the incurrence of the cost) and assign them liability too. Simply, it may be a proxy for an extension of the chain of causation.

Id. at 1302.

Thus, it is not surprising that the same court that issued the *KN Energy* decision has stated, "[o]ne of the fundamental equitable principles of ratemaking is that costs should be borne by those who benefit from them." *Gulf Power Co. v. FERC,* 983 F.2d 1095, 1100 (D.C. Cir. 1993); *see also City of New Orleans v. FERC,* 875 F.2d 903, 905-06 (D.C. Cir. 1989), *cert. denied sub nom. Mississippi v. Federal Energy Regulatory Comm*, 494 U.S. 1078 (1990) (approving, pursuant to the cost causation principle, an allocation of the cost of nuclear facilities based on benefits received)[26]; *Louisiana Pub. Serv. Comm. v. FERC,* 174 F.3d 218, 228 (D.C. Cir. 1999) ("FERC's judgments on these questions of benefits readily support its application of the well-settled principle that the costs associated with ERS units (whether

[26] SMUD cites this case to show that evaluating benefits received offends the conclusion reached by the Court. SMUD BOE at 39. To the contrary, the Court relied exclusively on a benefits analysis in its cost causation examination. SMUD also finds the evaluation of benefits inconsistent with the language of Order No. 888 favoring direct assignment of costs to those the cause them to be incurred. SMUD BOE at 38, *citing* Order No. 888. SMUD ignore that the Commission, in Order 888-A approved credits for customer-owned facilities based on a benefits analysis: "Only if they are integrated will the transmission system benefit and only then, the Commission decided, should credits – which shift the costs of the customer's facilities to the transmission provider's customers – be allowed." Order 888-A, ¶ 31,048 at 30,271. In other words, if the transmission provider's customers benefit from the facilities, *even though they did not "cause"— in the sense SMUD wishes to use "cause" – the cost of those facilities to be incurred*, they can be charged for the facilities.

construction expenses incurred in the past or maintenance costs incurred today) should be borne by those who benefit from them."). The type of benefit analysis performed in the Initial Decision is thus an appropriate application of the cost causation principle.[27]

In its arguments regarding cost causation, SMUD also attacks the Initial Decision's conclusions regarding the ISO's Control Area responsibilities, asserting that under the Western Electricity Coordinating Council's ("WECC's") Minimum Operating Reliability Criteria ("MORC"), reliability is a shared responsibility between the ISO and utilities in the Control Area. SMUD BOE at 32-34. The ISO does not quarrel with the proposition that utilities have reliability responsibilities. Ultimate responsibility, however, lies with the Control Area operator, and certain responsibilities can only be undertaken by the Control Area operator. The Control Area operator must ensure that Operating Reserves are adequate. Exh. ISO-11 at 5. Thus, the ISO must monitor Ancillary Services. Tr. 1984:12-25. Automatic Generation Control providing regulation must be under the Control Area operator's control. The MORC define "Automatic Generation Control" as "[e]quipment that automatically adjusts a control area's generation from a central location to maintain its interchange schedule plus frequency bias." Exh. ISO-11 at 7; ISO-43 at 1. The MORC also require that the Control Area operator direct the generation under AGC. Exh. ISO-33 at 7. 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 providing Regulation service to the ISO respond, not

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27 CCC and CAC/EPUC argue that the Initial Decision inconsistently applied ratemaking principles by evaluating benefits with regard to CAS and only causation with regard to other components of the GMC, contrary to the principles set forth in *United Distribution Cos. v. FERC,* 88 F.3d 1105 (D.C. Cir. 1996). CCC BOE at 16; CAC/EPUC BOE at 42. In *United Distribution Cos*., however, Court remanded the case to FERC because it had used inconsistent principles in allocating the same costs to two different segments of the industry. The Initial Decision was concerned with two different types of cost. Moreover, as discussed in the text, the benefits analysis included in the Initial Decision is at its core a cost causation analysis. Until recently, the WECC was named the Western Systems Coordinating Council ("WSCC").

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. SMUD's shared responsibility for reliability does not allow the ISO to avoid the cost of performing these functions.

Similarly, the fact that SMUD self-provides some services does not imply that SMUD does not benefit from the ISO's CAS. SMUD's argument that the ISO's witness admitted SMUD's self-provision obligation and its compliance with those obligations, SMUD BOE at 36, is disingenuous. SMUD's further claim that the ISO admitted that SMUD's services are the same as CAS, SMUD BOE at 39, is outright erroneous. The ISO's witness specifically noted that SMUDs services are not CAS, because they are provided on a service area, not a Control Area, basis. Tr. 957:1-4. They are more appropriately called "service area territory services." Tr. 957:2-3 Only the Control Area operator can provide CAS. Tr. 957:1 – 958:14.

This conclusion is apparent from SMUD's own discussion in its Brief. For example, it notes it is obligated to coordinate outages *with the Control Area operator*. SMUD BOE at 34. The coordination by the Control Area operator, with SMUD and every other entity with whom it must coordinate in the Control Area, requires the expenditure of resources that must be recovered through the CAS. SMUD states that it must schedule resources to meet Load integrated on a real time basis, according to procedures established with SMUD and PG&E. SMUD BOE at 35. The ISO, however, must evaluate those schedules and determine their impact on the Control Area. Tr. 1986:1-10. SMUD says it must maintain Load shedding equipment in accordance with WECC criteria. SMUD BOE at 35. The ISO, however, must determine when Load shedding is necessary. *See* Exh. ISO-11 at 20-21. That SMUD may pay PG&E for certain services is an issue between SMUD and PG&E. It does not affect the need for the ISO to perform the CAS or the propriety of the ISO allocating the charges for the CAS that the ISO performs to SMUD's Load (regardless of whether SMUD or PG&E pays the charges).

Finally, SMUD argues that the entire Eastern and Western Interconnection is synchronized with the ISO Controlled Grid, and therefore all loads in those interconnections benefit from CAS to the same degree that SMUD does. This argument ignores the fact that NERC and the WECC establish certain responsibilities *according to Control Areas*.[28] During the period covered by the ISO's 2001 Grid Management Charge, SMUD was in the ISO Control Area and must share responsibility for the Control Area's performance of its functions. SMUD is no longer in the ISO Control Area. *See* Letter Order, Docket No. ER02-1641-000 (June 24, 2002).[29] It should now be its responsibility for the performance of Control Area functions for its load and any other Loads within its Control Area.

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28 *See* http://www.nerc.com/standards

29 A June 18, 2002 News Release is available at http://www.smud.org.

3. The Initial Decision Properly Concluded That The ISO Is Not Contractually Barred From Allocating The CAS Charge To SMUD's Behind-The-Meter Load

SMUD asserts the Initial Decision failed to implement the requirement that the ISO honor existing contracts. SMUD cites both its Interconnection Agreement and the Interim Agreement with the ISO. The conclusion of the Initial Decision, however, is both reasonable and supported by the evidence.

The ISO does not contest its well-established obligation to honor existing contracts. The fundamental flaw with SMUD's argument regarding the Interconnection Agreement is that the ISO's allocation of CAS costs to SMUD's Load does not violate that agreement. The CAS charges do not interfere with SMUD's transmission rights; they do not interfere with SMUD's self-provision of Ancillary Services; they do not interfere with SMUD's ability and obligation to perform various services for its facilities and Load.

The Interconnection Agreement does not require or permit SMUD to self-provide CAS. Under the Interconnection Agreement, SMUD does self-provide a number of services for its transmission facilities, generation facilities, and Loads, many of which affect reliability in the same way that similar services provided by SCE, PG&E, or SDG&E affect reliability. Exh. ISO-29 at 17:18 – 19:3. As the ISO explained above, these are not CAS, but "service area territory services." Tr. 957:2-3

Actually, the *only* reference in the Interconnection Agreement to "control area services" is in connection with services that PG&E is to provide. Exh. SMD-24 at § 4.1. Although PG&E may have, prior to April 1, 1998, provided control area services for SMUD's Loads that are analogous to those provided by the ISO – whether pursuant to the Interconnection Agreement or otherwise – PG&E is no longer Control Area operator and cannot therefore provide CAS. The ISO's provision of those services and the allocation of the costs of those services to SMUD's Load do not implicate any terms of the Interconnection Agreement. This conclusion holds regardless of whether the Commission determines that PG&E or SMUD pays those charges. If the former, then the Commission must determine whether the Interconnection Agreement precludes PG&E from collecting the costs from SMUD. If the latter, then – to the extent that PG&E is actually obligated to provide the services under the Interconnection Agreement – SMUD can seek to recoup the costs from PG&E. Nothing in SMUD's Interconnection Agreement is inconsistent with the allocation of CAS charges to SMUD Load that is not served over the ISO Controlled Grid.

SMUD also contends that the Restated Interim Agreement prohibits the ISO from allocating CAS to SMUD Load that is not served over the ISO Controlled Grid. SMUD BOE at 28. The Initial Decision concluded to the contrary, relying upon the plain language of Section 4.3:

> If FERC issues any rulings or orders with respect to issues included in this Agreement, including the Grid Management Charge settlement, other ISO charges and Scheduling Coordinator requirements, the impacted Parties agree to abide by such rulings or orders once they are finalized.

99 FERC at 65,111, citing Exh. SMD-23. SMUD contends that this language is not applicable because the application of the GMC charge to SMUD's Load is not an "issue" under the Restated Interim Agreement. SMUD contends that there is no "issue" because all such charges were fully determined by the Restated Interim agreement, and explains the terms of the Restated Interim Agreement at great length to prove its point. SMUD BOE at 48-54. The problem with SMUD's argument is that if its interpretation were correct, section 4.3 would be meaningless. There would be no "Grid Management Settlement, other charges and Scheduling Coordinator requirements" that would be subject to Commission rulings. Stan-

dard rules of interpretation, however, preclude interpreting language so as to deprive it of meaning.[30]

The only reasonable interpretation of the phrase "issues included in this Agreement" is the subject matter that is covered by the Restated Interim Agreement. Accordingly, the Initial Decision correctly determined that the determination of charges under the Restated Interim Agreement is subject to a Commission decision that different charges are appropriate.

G. The Initial Decision Properly Found That It Is Just and Reasonable To Allocate CAS Charges to Retail Behind-The-Meter Load [Section I.F.1 of the Initial Decision]

The Initial Decision concluded that the ISO's proposal to allocate CAS charges to retail behind-the-meter Load (in particular, behind-the-meter Load served by QFs) is just and reasonable. CAC/EPUC, SCE, CCC, and Industrial Associations take Exception to this conclusion. The arguments on exceptions fall into five general categories: (1) that the ISO's proposal violates the Public Utilities Regulatory Policy Act of 1978 ("PURPA"); (2) that the ISO's proposal discriminates against behind-the-meter Load served by QFs; (3) that the Initial Decision is inconsistent with principles of cost causation; (4) that the Initial Decision is inconsistent with the Initial Decision in Docket No. ER98-997, *California Independent System Operator Corp.*, 96 FERC ¶ 63,015 (2001); and (5) that the Initial Decision is contrary to public policy.[31]

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30 *See, e.g., Amoco Energy Trading Corp.*, 94 FERC ¶ 61,225, at 61,820 n.12 (2001); *Great Lakes Gas Transmission Limited Partnership and Ocean Energy Resources, Inc.*, 93 FERC ¶ 61,008, at 61,019 (2000). *Public Service Co. of New Hampshire v. Hampshire Electric Cooperative, Inc.*, 86 FERC ¶ 61,174, at 61,598 (1999).

31 CAC/EPUC also argues that the Initial Decision improperly shifts costs to customers with behind-the-meter generation. Because the argument is merely an amalgam of CAC/EPUC's other arguments, the ISO will not address it separately.

1. The Initial Decision Correctly Concluded That The ISO's Proposal Does Not Violate PURPA

CAC/EPUC first contend that the Initial Decision failed to recognize significant distinctions between retail and wholesale behind-the-meter Load, and thus violates PURPA. CAC BOE at 20-27. The Initial Decision did not conclude that there was no distinction between retail and wholesale behind-the-meter loads, but rather, "The same rationale and findings . . . supporting the allocation of CAS costs based on [Control Area Gross Load] to "wholesale" behind-the-meter Loads, are equally applicable to "retail" behind-the-meter Loads." 99 FERC at 65,118. CAC/EPUC's discussion of the distinctions[32] is therefore irrelevant unless those distinctions undermine the Initial Decision's conclusions.[33] CAC/EPUC have not shown that they do.

CAC/EPUC contends that the ISO proposal violates PURPA's requirements of "net treatment" of QFs and for the provision of back-up and maintenance power, as well as the prohibition of the assumption of simultaneous QF outages.[34] They assert that the Initial De-

[32] The ISO does not disagree that behind-the-meter Load served by QFs is different in many ways from the internal Load of GEs. The ISO does disagree with two of CAC/EPUC asserted distinctions. First, CAC/EPUC asserts – citing their own witness – that behind-the-meter Load served by QFs is not part of the ISO's Load Responsibility. Although Judge Leventhal reach that conclusion in his Initial Decision in Docket No. ER98-997, 96 FERC at 65,138-39, that decision is before the Commission on Exceptions. Judge Leventhal's decision is directly at odds with the testimony of the WECC witness in those proceedings and the position taken by the WECC in its Brief on Exceptions. Second, CAC/EPUC challenges that Initial Decision's conclusion that there is a measurable energy flow between a QF serving behind-the-meter Load and the utility system. CAC/EPUC's own witness admitted that variation of electricity flows would mean that the boundary meter would not read zero. By definition, the flows are therefore measurable.

[33] CAC/EPUC's citations of Commission decisions in this regard do not advance its case. In Order No. 888-B, the Commission merely decided to examine the applicability of charges on a case-by-case basis. Order No. 888-B, 81 FERC at 62,091. The decision does not predetermine whether retail and wholesale behind-the-meter Loads should be distinguished in his case. In *PJM Interconnection, LLC*, 95 ¶ FERC 61,470 (2001), the Commission found permissible exclusions of station auxiliary Load from transmission charges and Ancillary Services charges. The Commission provided no indication, however, that these exemptions should extend to retail behind-the-meter Load served by QFs. Indeed, the Ancillary Services exception applied to remotely served station Load, and was based on billing complications.

[34] SCE asserts that the ISO's proposal circumvents Federal and State net metering policies. The validity of the ISO's proposal, however, cannot be determined by metering policies. If, as the ISO contends, it is just

cision failed to address these arguments, and should therefore be modified. These arguments, however, were fully briefed and the Initial Decision acknowledged CAC/EPUC's assertions that PURPA precluded the ISO's proposal. The statement that arguments not ruled upon were considered and rejected indicates that the Initial Decision found these arguments unpersuasive.

The Initial Decision's rejection of these arguments is sound. In support of its argument that PURPA requires net treatment of QFs, CAC/EPUC cite only Commission regulations that distinguish between supplementary power (provided to a facility as a supplement to its QF generation) and back-up and maintenance power (provided when the QF generation is unavailable). According to CAC/EPUC, these rules require net treatment for the allocation of costs. This is a *non sequitur*. The cited rules pertain only to the availability of and rates for the provision of Energy. They do not address the allocation of the costs of maintaining Control Area reliability. Moreover, unlike the costs of providing Energy that are determined by amount and frequency of use, the CAS costs are primarily fixed, Tr. 303:14-21, and remain the same whether a customer uses the grid daily, weekly, or potentially at any moment. There is no inconsistency between allocating reliability costs to behind-the-meter Load and a rule that distinguishes between supplementary and back-up power.

CAC/EPUC's statement that the ISO assumes the simultaneous outages of QFs during system peak hours for the purpose of allocating CAS charges for back-up and maintenance power fares no better. CAC BOE at 25-26. That statement reveals the underlying fallacy of CAC/EPUC's argument about assumed outages. The ISO does not allocate CAS charges for back-up and maintenance power. The ISO allocates CAS charges as the costs

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and reasonable to allocate CAS to behind-the-meter Load served by QFs, then such Load should not be able to avoid those costs simply because of metering policies.

associated with maintaining reliability. It allocates such CAS charges to Control Area Gross Load because these services are provided at all times, not just when a unit and its associated behind-the-meter load are receiving back-up and maintenance power.[35] 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.

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 contrib-

[35] That the CPUC might decide to allow Scheduling Coordinators to pass these rates through to QFs in back-up and maintenance rates does not change this fact. The CPUC rate-making principles for back-up and

ute 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.

CAC/EPUC also cites an ISO statement that it assumes a given QF could fail completely, and asserts that, when applied to all QFs, the ISO has assumed a 100 per-cent outage of QFs. CAC BOE at 10. Again, this is a *non sequitur*. That the ISO assumes that a given QF could fail completely merely means that the QF has the potential for failure and therefore needs reliability services. It does not imply an assumption that, at any given time, the QF will fail. Thus, the ISO assumes that 100% of QFs have the potential to fail completely and therefore need reliability services. It does not follow that the ISO assumes that they all will fail completely.

CAC/EPUC also argues that the ISO's estimation methodology for behind-the-meter Load served by QFs assumes a simultaneous outage of 100% of QF Generation. CAC/EPUC BOE at 11. The ISO's methodology, however, makes no assumption and the cited testimony does not support a conclusion that it does. CAC/EPUC's counsel asked ISO witness Price how he would calculate Control Area Gross Load if all QF Generation were to simultaneously become unavailable. Dr. Price acknowledged that the calculation would be the same as that proposed for calculating Control Area Gross Load. Tr. 849:8 – 852:16. CAC/EPUC errs when from that fact they infer that the ISO's methodology makes an assumption that all QF Generation will simultaneously become unavailable.

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maintenance power are not relevant to this service.

Dr. Price's calculation of behind-the-meter Load reaches the same result if he assumes that all QF Generation serving that Load is unavailable for the simple reason that the calculation is the same regardless of the availability of the QF Generation. The ISO methodology does not rely upon any assumption about the availability of QF Generation. The calculation is based on Demand, not Generation. Control Area Gross Load is defined as "all Demand for Energy within the Control Area" (with minor exceptions). ISO Tariff (Exh. J-2) First Revised Sheet 308 – Original Sheet 308A. It matters not whether the Load creating the Demand is served by on-site Generation or any other source of Generation. The calculation is the same whether one assumes that all QF Generation is available or whether one assumes that it is all unavailable. It can be said as easily that the ISO's estimation process results in an assumption that eighty percent, or fifty percent, or zero percent, of QF Generation is unavailable, as that it results in an assumption that 100 percent is unavailable. CAC/EPUC's conclusion is, once again, a *non sequitur*.

2. The Initial Decision Properly Concluded That The ISO's Proposal Does Not Discriminate Against QFs

CAC/EPUC and SCE contend that the Initial Decision's approval of the ISO's proposal is erroneous because the proposal discriminates against behind-the-meter Load service by QFs. CAC BOE at 29-31; SCE BOE at 11-12. They assert that such Loads are charged according to potential Demand, while other Loads are charged according to actual Demand. There is good reason for the Initial Decision's rejection of this argument.

The fallacy of this argument is that it rests entirely on the erroneous characterization of behind-the-meter Load served by QFs as "potential load." *Id.* The only basis offered for this characterization – other than the assertions of CAC/EPUC's and SCE's own witnesses – is testimony by Mr. Leiber and Mr. Lyon.

Mr. Leiber agreed that retail customers without self-generation are billed not on what they could potentially operate, but on what they actually operate and draw from the system, and that "those rules" would not apply to customers using self-generation. Mr. Lyon's testimony (that CAS charges for Loads served by QFs would not be based on the reading of a meter at the site boundary, while charges for other Loads would) is to the same effect. This testimony is accurate: customers served by self-generation would not be billed CAS according to the Energy that they draw from the ISO Controlled Grid (or the distribution system). See ISO Tariff (Exh. J-4), Appendix A, First Revised sheet No. 308 – Original Sheet No. 308A (definition of Control Area Gross Load). This does not mean that such customers are billed according to "potential load." That conclusion requires a definition of "load" limited to times when it draws energy from the transmission grid. Nothing in the record supports such a limitation.

Indeed, Mr. Lyon explicitly testified that retail behind-the-meter Load is not "potential" load, but is actual load. Exh. ISO-29 at 33:7-12; Tr. at 1202:25 – 1204:11. If a behind-the-meter Load served by QF Generation has the potential to consume 100 MW, and is consuming 50 MW, it has 50 MW of actual Load and 50 MW of potential Load. It would be billed CAS charges for the 50 MW of actual Load and not for the 50 MW of potential Load. In that manner, it is treated identically to customers without self-generation. Exh. ISO-29 at 36:12 - 16.

CAC/EPUC offer the analogy of a toll road to prove its point, asserting that the ISO charges the tolls to one subset of customers only when they use the toll road and to another subset regardless of whether they use the toll road. This analogy is incomplete. The toll can be better compared to the ISO's transmission Access Charge, which is not at issue in this proceeding. The toll covers the capital costs and maintenance, much as the Access Charge covers Participating Owner's Revenue Requirements, and is only charged to those that use the toll road. The operation of the toll road requires other services, more analogous to CAS. It requires police to monitor driving, and emergency services to respond to accidents. The toll road must be built, operated, or expanded, consistent with regional planning requirements. The costs of these and other services are borne not by the users of the road, but by the taxpayers in general – in the same manner that CAS should be borne by Control Area Gross Load.

SCE contends that the Initial Decision failed to recognize that CAS charges are allocated to all Load except behind-the-meter Load served by QFs according to usage of transmission and distribution facilities in the Control Area, and therefore discriminate against the behind-the-meter Load served by QFs. SCE BOE at 11-12.SCE errs. The CAS charges are allocated according to Control Area Gross Load – the Demand within the Control Area – regardless of usage of the facilities. In the case of many Loads, Control Area Gross Load will coincide with usage of the ISO Controlled Grid; in others, it will coincide solely (from a contract path perspective) with usage of a distribution system; with others it will coincide with usage of the transmission or distribution facilities of a GE; with behind-the-meter Loads served by QFs, it will coincide with the usage of the electrical lines between the QF and the Load. In each case, however, it is *Demand* that is determinative regardless of where it is, or could be, metered. There is thus no discrimination.

The Initial Decision rejected SCE's argument that the ISO's proposal is discriminatory because CAS are not allocated to station power load. 99 FERC at 65,122-123. SCE contends that the Initial Decision errs. SCE BOE at 19-21. It asserts that the Initial Decision's reliance on the size of station power load does not distinguish it from behind-the-meter Load served by QFs. It also states that there is no basis for the distinction because the Commission approved net metering for station power load, and California has deemed net meter acceptable for behind-the-meter Load served by QFs. *Id.* That conclusion does not hold. The Commission has found the fact that station auxiliary power is used for the production of Energy highly relevant. As the Commission Staff discussed in its Initial Brief at 19, the Commission noted in *PJM Interconnection, LLC, et al.*, 94 FERC ¶ 61,251 (2001), *reh'g denied,* 95 FERC ¶ 61,333 at 61,889-91 (2001), that station power, if supplied by the Generating Unit and if less than the Generating Unit's gross output, has historically been viewed as "net generation" or "negative generation." It is an internal cost of operating the facility and enabling it to generate electricity. Consistent with that approach, Energy used to serve station Load is not included in the maximum output that a QF is permitted to sell under Commission regulations; being consumed in the production of Energy, it does not displace Energy on the system. *See Penntech Papers*, 48 FERC ¶ 61,120 (1989). The only time the Commission has analogized station auxiliary Load and retail behind-the-meter Load, to the ISO's knowledge, was to determine that net billing of Energy sales was not preempted by Federal law. *Mid-American Energy Co.*, 94 FERC ¶ 61,340 (2001).

3. The Initial Decision's Approval Of The Allocation Of CAS To Retail Behind-The-Meter Load Served By Qualifying Facilities Is Consistent With Cost Causation Principles

CAC/EPUC make three arguments that the Initial Decision's approval of the allocation of CAS to retail behind-the-meter load served by QFs violates cost causation principles.[36] The cost causation arguments of other intervenors involve one or more of the same arguments.

CAC/EPUC's third argument, which is echoed by CCC and Industrial Associates, asserts that the Initial Decision's evaluation of benefits if inconsistent with cost causation principles. CAC BOE at 38-43; CCC BOE at 9-20; IA BOE at 14-18. This argument is addressed above under Section VI.F.

CAC/EPUC's first argument is that the ISO's "jurisdiction" is limited to the ISO Controlled Grid and that the private property upon which retail Load operates is not part of the ISO Controlled Grid. CAC/EPUC BOE at 32. The Initial Decision rejected these arguments, primarily because the benefits provided by CAS are not determined by "use" of the ISO Controlled Grid. 99 FERC at 65,119-120. CAC/EPUC resurrects this argument through a tortured effort to show that the ISO's Load Responsibility does not include behind-the-meter Loads served by QFs. CAC BOE at 32-37.

CAC/EPUC correctly note the WECC definition of the ISO's Control Area "load responsibility": the "Control Area firm load demand." *Id.* at 33; Exh. ISO-43 at 5. The WECC does not define firm load demand for this purpose. CAC/EPUC want the Commission to conclude that firm load demand does not include behind-the-meter Load served by QFs.

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[36] CAC/EPUC's cost causation arguments also include an argument that the ISO is compensated for any benefits that it provides to behind-the-meter Loads served by QF through standby charges. CCC makes a similar argument, alleging double charging, in connection with its discrimination argument. In each case, the argument is simply a rehash of the contentions made in other arguments. The Initial Decision, at page 65,119, adequately disposed of argument regarding standby rates:

> CAS costs are not dependent on or governed by the delivery of energy. CAS is not the cost of providing or securing operating reserves, ancillary services, or standby service." It is not a usage charge or a transmission access charge. It is a charge for the ISO's fixed costs of maintaining a reliable system 24/7. The CAS charge is to recover the ISO's administrative costs for CAS services provided by the ISO to ensure that Energy will be available and delivered if and when needed. Exh. ISO-29 at 15:5 – 16:8. Other entities cannot self-supply CAS. Exh. S-1 at 18-1, Tr. 957. Thus, as the ISO points out, UDCs are not reducing the need for CAS by providing Standby Service.

CAC/EPUC rely upon testimony and cross-examination 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 at 7.

CAC/EPUC offer various procedural arguments that the Commission should ignore WECC's Brief on Exceptions filed in Docket No. ER98-997, which states that firm load demand does include behind-the-meter Load served by QFs. CAC/EPUC BOE at 36. CAC/EPUC ignore the deposition testimony of WECC staff, included in the evidence, that takes the same position. Exh. ISO-30 at 10-13. It also ignores the letter, included in the evidence, from the chairman of the WECC Operating Committee, to the same effect. Exh. ISO-51. CAC/EPUC do contend, however, that the staff position should be ignored (despite the WECC's staff's authority to interpret the MORC) because it has not been presented to and approved by the WECC. CAC/EPUC BOE at 35.

CAC/EPUC also volunteers "on information and belief" that the Compliance Monitoring and Operating Practices Subcommittee ("CMOPS") of the Operating Committee has rejected that position. This is not determinative. The Commission can take judicial notice of material on the WECC web site. The last meeting of the Compliance Monitoring and Operating Practices Subcommittee was on May 8-10, 2002.[37] The minutes of a subsequent May 23-24 meeting of the MORC Working Group of the Compliance Monitoring and Operating Practices Subcommittee are available. Those minutes state:

> CAISO has a question as to calculating Load Responsibility for a Control Area when a generator (mainly a QF facility) is serving a load behind the telemetric metering to the ISO. Should the load the QF is supplying be included in calculating the Load Responsibility, and subsequent reserve obligations, of the Control Area? . . . WECC has interpreted the policies to read that the Control Area should include the load behind the meter when performing their load responsibility. . . . MORCWG concurs with the Nov 29 [Operating Committee] letter written in discussion of this topic and that they were correct in their interpretation of MORC's requirements and it[s] inclusion of the small QF and IPP generators (and their non-metered customer loads) in calculating the load responsibility for the Control Area.[38]

CMOPS is just a subcommittee of the Operating Committee, which apparently has not acted. WECC staff's interpretation remains operative. More importantly, however, CAC/EPUC's semantic "jurisdiction" argument obscures the real issue: whether as a practical matter the ISO must take behind-the-meter Load into account in ensuring the reliability of the Control Area grid. The Initial Decision understood this, and rejected the argument. 99 FERC at 65,119-120.

CAC/EPUC's second cost causation argument, which SCE also advances, is that the behind-the-meter Loads served by QFs do not cause or benefit from CAS because the ISO

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[37] http://www.wecc.biz/committees/OC/CMOPS/Meetings/index.html

[38] http://www.wecc.biz/committees/OC/CMOPS/MORCWG/Meetings/minutes/MORCWG_Min_5-23-02.pdf

performs various functions on a net basis. CAC BOE at 37-38; SCE BOE at 15; *see also* SCE BOE at 18.[39] This issue, however, does not concern whether the ISO should or should not use data on the Demand of Control Area Gross Load or whether that data would enhance reliability. This issue concerns whether the use of the Control Area Gross Load billing determinant is justified because the ISO incurs CAS on behalf of behind-the-meter Load. That the ISO *uses* net data does not in any manner imply that the ISO *performs* CAS only for net Load, or that behind-the-meter Load does not cause the ISO to incur CAS costs.

Thus, while the ISO only receives schedules for net Load, Tr. 1185: 5- 14, the coordination of schedules increases the likelihood that sufficient transmission capacity will be available to serve behind-the-meter Load in the event of a Generation failure, Exh. ISO-10 26: 17- 28: 13, Tr. 1986: 8- 10. Although the ISO's Energy Management System can only account for net Generation, it will nonetheless detect a failure of a Generator serving behind-the-meter Load (without knowing where the failure occurred), and the units providing Regulation service will respond to serve the gross Load. Exh. ISO-29 at 15:15 – 16:4. Similarly, with regard to each of the CAS cited by CAC/EPUC, the service improves the reliability of the Control Area transmission grid, and increases the likelihood that imbalances, which occur on an interconnected system as well as between behind-the-meter Load and its host Generation can be addressed both on a moment-to-moment basis and in the event of a complete failure of that Generation. Exh. ISO-10 15:4 –16: 4. The ISO is thus performing the service on behalf of behind-the-meter Load, even though it uses data on the Demand of net Load.

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[39] SCE asserts that the ISO has not shown that behind-the-meter Load is part of its load responsibility because it does not procure Ancillary Services for such Load. The ISO's load responsibility is at issue in Docket No. ER98-977, and is discussed in the preceding text. The ISO does believes it should procure such Ancillary Services and should have the gross metering data necessary to determine the appropriate amount. *See, e.g.*, 96 FERC at 65,137-38. It is SCE and CAC/EPUC that are contesting the ISO's authority to do so. Having delayed the ISO's implementation of such policies, they should not be heard to use their – perhaps temporary – success as evidence against the ISO.

SCE also offers a new variant on this argument. It argues that the billing determinant for transmission access and CAS should be the same, because prior to the ISO, all control area services, except for scheduling and dispatching, were wrapped into a utility's transmission revenue requirement, which was recovered through transmission access charges. SCE BOE at 14. SCE asserts that the ISO's unbundling should not change that result. The entire purpose of unbundling, however, is to better allocate costs according to the services received. The fact that certain behind-the-meter Loads were not previously allocated costs according to services received is not a valid basis for rejecting such an allocation now.

4. The Initial Decision In Docket No. ER98-997 Does Not Control The Outcome Of This Proceeding

CAC/EPUC and Industrial Associations contend that the Initial Decision is inconsistent with the Initial Decision in Docket No. ER98-997. *See* CAC BOE at 49-52; IA BOE at 18-19. As the Initial Decision recognized, however, the issue here is entirely distinct. 99 FERC at 65,120. Docket No. ER98-977 was concerned with procurement of Ancillary Services for behind-the-meter Load served by QFs, scheduling of behind the meter Load, and a gross metering and telemetry requirement. 96 FERC at 65,134-145. Allocation of CAS charges to behind-the-meter Load does not involve the procurement of Ancillary Services, it does not require scheduling of that Load, and it does not entail gross metering. There is no reason that the resolution of the "gross v. net" issue in one proceeding is determinative for all others. Indeed, even if the Commission were to approve interpretation of the ISO's load responsibility used in the Initial Decision in Docket No. ER98-997 – which the ISO believes is manifestly erroneous – it would not resolve the issue in this proceeding. The determinative question here is whether behind-the-meter Load served by QFs receives CAS services from the ISO, and is thus responsible for the costs of those services. The Initial Decision in Docket No. ER98-977 does not address that question.

More importantly, the Initial Decision in Docket No. ER98-997 is just that – an initial decision. It is not a final Commission decision with precedential value. As such it is on a par with the Initial Decision in this proceeding; neither is entitled to greater weight. Each is before the Commission on exceptions. If there are inconsistencies, the Commission will resolve them. The Commission will evaluate each Initial Decision according to the record evidence and the soundness of the legal reasoning – not the chronological order in which they were rendered. The Initial Decision in Docket No. ER98-997 is thus entitled to no particular deference in this proceeding.

5. The Initial Decision is Consistent with Public Policy

CAC/EPUC, in their Considerations Warranting Commission Review, and Industrial Associations contend that the Initial Decision is contrary to public policy as set forth in PURPA and the national energy policy. CAC BOE at 13-16, 18-20; IA BOE at 23-26.[40] These contentions rely upon false statements regarding the impact of the Initial Decision, exaggerated estimates of the costs imposed by the Initial Decision, and unsupported assumptions about Generator behavior. CAC/EPUC state:

> The ISO and the Initial Decision propose to deviate from this historical practice [of net metering] and cause additional and unnecessary costs associated with, at a minimum, procuring additional operating reserves, based on redefining how customer generation is viewed. Rather than acknowledging the integrated nature of the customer's generation and industrial process and metering the customer at the site boundary, the ISO and the Initial Decision would engage in a myth that all the customer's generation was sold into the ISO-Controlled Grid and that all the customer's industrial load was served by

[40] Industrial Associates also assert the Initial Decision is consistent with the Commission Standardized Market Design. IA BOE at 27. The policies that IA discusses, however, are applicable to all load and concern reserves and imbalance energy needs. They merely provide for self-provision. CAS do not involve the actual cost of Ancillary Service and Imbalance Energy.

> power deliveries off the ISO-Controlled Grid. *This would result in a situation where retail customers with self-generation would have to schedule self-generation from the end-use customer's generator to the customer's load even though the power remains on-site and never flows over the electric utility system.*

CAC BOE at 12 (emphasis in the original). *See also* IA BOE at 3. This diatribe is simply and completely *false*. Nothing in the Initial Decision requires gross metering. Nothing in the Initial Decision permits or requires the procurement of Ancillary Services for behind-the-meter Load. Nothing in the Initial Decision requires that such Load be scheduled. Moreover, although the ISO has advocated such positions in other proceedings, nothing in the ISO's proposal in this proceeding would require any such result.

CAC/EPUC concede as much on the next page when it identifies the costs that behind-the-meter Loads would bear if all of the ISO's proposals in various proceedings were approved. CAC BOE at 13. These other charges are not before the Commission in this proceeding; the Commission can independently judge the reasonableness of those charges. They should not, and cannot, be a consideration here.

CAC/EPUC and Industrial Associations go on to assert that allocating CAS to behind-the-meter Load served by QFs will cause a moratorium on the construction of distributed generation and will cause existing QFs to island from the Grid. CAC BOE at 13; IA BOE at 24. As the Initial Decision noted, there is no supporting evidence for this claim, only speculation:

> [A]lthough (CAC/EPUC witness Ross] 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. Tr. 2015:1 - 2018:6. Further, his more generalized analysis omitted the cost of Energy. Tr. 2018:7-15. The ISO persuasively argues that the Energy costs that can be avoided by self-generation overwhelm the costs evaluated by Mr. Ross (see Exh. ISO-42), and that it is impossible to evaluate the benefits of self-generating without considering those costs.

99 FERC at 65,123. The fact that Mr. Ross' analysis also did not include such matters as the capital cost of self-generation, *see* CAC BOE at 13, n.5, highlights, rather than compensates for, its irrelevance. The lack of evidence is particularly suspect because CAC and EPUC, as associations of co-generators, are well-positioned to provide real cost and market data. The Commission should not reject an otherwise reasonable rate design based on pure speculation.

More generally, CAC/EPUC appear to believe that any policy that imposes any additional costs on cogenerators should be *per se* impermissible. This proposition – that the Commission must eschew any policy that might reduce in any degree the incentives for co-generation – is simply implausible. Section 210, as quoted by CAC/EPUC, requires the Commission to establish "such rules *as it deems necessary* to encourage cogeneration." *Id.* (emphasis added.) The statute vests in the Commission the discretion to determine what rules are necessary. It does not require the Commission to take every possible step to maximize the profits of cogenerators; neither does it require the Commission to advance cogeneration at the expense of all other considerations, such as system reliability. It also does not override the Commission's other responsibilities, such as ensuring just and reasonable rates, as through the avoidance of cost-shifts. *See* 16 U.S.C. § 824d. Even PURPA itself recognizes limits on "encouraging" cogeneration. *See* 16 U.S.C. § 824a-3 (limiting rate to utilities' incidental costs). That the ISO's proposal, by holding cogenerators responsible for a share of the costs of CAS, will impose additional costs on those cogenerators does not render the policy unjust or unreasonable.

H. The Initial Decision Properly Found That The ISO's Methodology For Allocating Control Area Services Charges to Retail Behind-the-Meter Loads Is Just and Reasonable [Section I.F.2 of Initial Decision]

The Initial Decision determined that it is reasonable to conclude that parties with behind-the-meter Loads that elect not to permit the ISO to perform metering behind the point of interconnection, or to provide the ISO with actual behind-the-meter Load data, should be deemed to have agreed to an estimation of that Load for purposes of the allocation and billing of CAS charges by virtue of their continued interconnection to the Grid. 99 FERC at 65,129-30. CAC/EPUC, CCC and SCE take exception in whole or in part to this conclusion.

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 Utility Distribution Companies ("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.

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.

CAC/EPUC and CCC contend that the ISO's methodology conflicts with 18 C.F.R. § 292.305(c) because it assumes that outages of all qualifying facilities will occur simultaneously. CAC BOE at 53-54; CCC BOE at 25-26. As described in greater detail in section G, in no manner is the particular performance of on-site Generation an element of the ISO's estimation method. As Dr. 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. Because the estimate is based on Demand, not Generation, the ISO methodology simply does not rely upon any assumption about the availability of QF Generation.

CAC/EPUC and CCC also contend that the ISO's estimation methodology is discriminatory. They raise no arguments, however, that were not raised in connection with Issue I.F.1. These arguments are addressed in Section G of this Brief.

CCC asserts that the Initial Decision fails to take into account that the ISO's methodology is not contained in the tariff filing. CCC BOE at 26-27. While it acknowledges that the Initial Decision also would require the ISO to file the methodology, CCC asserts that this is an insufficient basis to conclude that the methodology is just and reasonable. *Id.* at 27. The Initial Decision, however, did not merely rely upon the filing as the basis for approval of the methodology. The Initial Decision discussed the specifics of the methodology – which, as discussed above, are fully presented in the record – and concluded that the only issue that precluded its acceptability was the ISO's failure to include it in the tariff. 99 FERC at 65,130. A compliance filing to correct that single deficiency is consistent with standard Commission practice.

CAC/EPUC also argues that the estimation methodology is inconsistent with the ISO's obligation to honor existing power purchase agreements, which provide for net metering and net billing for Energy purchases. CAC BOE at 55-56. As the Initial Decision recognized, 99 FERC at 65,121, and as has been fully discussed above, the ISO's proposed allocation of CAS charges to Control Area Gross Load does not determine metering requirements and is not a sale of Energy. There is simply no conflict with the power purchase agreements.

SCE contends that the ISO's methodology is discriminatory because its does not take the behind-the-meter Load served by QFs in the territory of GEs and the station power load of QFs into account. SCE BOE at 21-24. It asks the Commission, if it approves the allocation of CAS charges to behind-the-meter Load served by QFs, to modify the methodology accordingly. *Id.* The ISO recognizes that the station power load and behind-the-meter Loads identified by SCE should be considered, despite a lack of data, *see* 99 FERC at 65,130, and will use its best effort to develop a methodology for including appropriate estimates in its methodology.

I. The Initial Decision Was Correct in Finding It Just and Reasonable to Apply the Control Area Services Charge to Mohave Participant Energy [Section I.G of Initial Decision]

The Initial Decision found that it was just and reasonable to apply the Control Area Services Charge to Mohave Participant Energy ("MPE"),[41] because "MPE both contributes to CAS costs incurred by the ISO and receives benefits from the CAS performed by the ISO." 99 FERC at 65,133. Moreover, if MPE were not assessed the CAS Charge, the result would be "improper cost shifting to other market participants." *Id.*

SCE has taken exception, *inter alia*, to what it describes as the Initial Decision's "finding it just and reasonable to allocate the CAS Charge to exports that are not scheduled on the ISO Controlled Grid and which are not the Load Responsibility of the ISO." SCE

[41] As used by the parties in this proceeding, 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 by entities other than SCE. *See, e.g.*, Ex. ISO-36 at 1:7-13. The Mohave Power Plant and the Eldorado Transmission System are within the ISO Control Area. *Id.* at 4:1-14.

BOE at 5. In framing the exception in this manner, SCE intends to capture the assessment of the CAS Charge on Mohave Participant Energy.

SCE argues that the non-Edison Mohave Participants never turned over Operational Control of their share of the Eldorado facilities to the ISO, and thus it is inappropriate for the ISO to assess them a share of the Control Area Services Charge. SCE BOE at 25. As the Initial Decision found, however, whether or not the Mohave facilities are considered part of the ISO Controlled Grid "is irrelevant to the provision of CAS." 99 FERC at 65,133.[42]

Should the Commission find that it *is* a matter of significance whether the facilities in question are under ISO Operational Control, however, the record demonstrates that they are. It is not true, as SCE would have it, that the MPE facilities were not turned over to ISO Operational Control. SCE is incorrect in stating there was no Section 203 filing made with the Commission to turn over the Mohave Participants' shares of the Eldorado Transmission System to ISO Operational Control. SCE BOE at 2, n. 2. On the contrary, such a Section 203 filing was made prior to the start up of the ISO and approved by the Commission. *See Pacific Gas and Electric Company, et al.,* 77 FERC ¶ 61,204 at 61,822-23 (1996). That Section 203 filing transferred the Eldorado transmission system, which is evidenced by the entry in Appendix A of the Transmission Control Agreement (Exh. J-10) and the ISO Register. Ex. ISO-33; Ex. ISO-36 at 3:17 – 4:14; Tr. 1823:25 – 1824:5. Moreover, the 203 filing necessarily transferred Operational Control over the complete facilities, since the ISO cannot maintain control over only part of a given facility. It must concern itself with the entire fa-

[42] The term "ISO Controlled Grid" is defined in the ISO Tariff as "The system of transmission lines and associated facilities of the Participating [Transmission Owners] that have been placed under the ISO's Operational Control." Ex. J-2, Original Sheet No. 327. Thus, a facility that is under the ISO's "Operational Control" is part of the "ISO Controlled Grid." The two terms are used to express the same idea.

cility, or with none of it. Ex. ISO-36 at 5:7-16. This fact is not only supported by simple logic, but acknowledged by SCE witness Mr. Minick in his testimony:

> The entire physical set of facilities (i.e., lines, transformers, etc.) that comprise both [the Southwest Power Link] and the Eldorado System arguably are both "physically" under the ISO's control because you cannot simply say that facilities A, B, and C belong to one co-owning utility and facilities E, F, and G belong to the others.

Ex. No. SCE-20 at 8. Mr. Minick also acknowledged that SCE exercised operational control of the *entire* Eldorado transmission line prior to the start-up of the ISO. Tr. 2194:14 – 2195:6.

What is true with regard to the entities over which the ISO exercises Operational Control also is true with regard to the entities that form part of the ISO Controlled Grid. In its "Statement of the Case", SCE states that MPE was exempted from responsibility to pay the GMC under the Settlement that preceded the 2001 GMC filing because the MPE was transmitted over the shares of the Eldorado system that were not owned by SCE, and hence, according to SCE, were not part of the ISO Controlled Grid. SCE BOE at 2. This is not correct. As a threshold matter, it is inappropriate to use the Settlement for any precedential purpose.[43] In fact, Judge McCartney rejected the admission of the Settlement into evidence as an exhibit in this proceeding, Tr. 1859:1-3, and stated in the Initial Decision that the Settlement is not precedent in this proceeding. 99 FERC at 65,134. More to the point, however, ISO witness Deborah Le Vine testified that the facilities' supposedly not being part of the ISO Controlled Grid was *not* the reason that MPE was exempted from paying the GMC un-

[43] SCE attempts to use the Settlement to demonstrate that since the facilities in question were characterized as not part of the ISO Controlled Grid under the Settlement (according to Edison), they therefore should be considered not a part of the ISO Controlled Grid now. As Ms. Le Vine has testified, however, the facilities are a part of the ISO Controlled Grid, and were considered to be so at the time of the Settlement, as well. Tr. 1818.

der the Settlement, and that, in any event, these facilities are a part of the ISO Controlled Grid. Tr. 1818.

Just as with the case of facilities under the ISO's Operational Control, if one co-owner turns over its share of a facility, then the entire facility is part of the ISO Controlled Grid. Tr. 1816. Therefore, MPE energy does, in fact, utilize the ISO Controlled Grid.

SCE further argues that although MPE derives some benefits from the services performed by the ISO for which the CAS Charge is intended to recover the cost, the level of such benefits is not great enough to warrant assessing a full share of the CAS Charge on MPE. SCE BOE at 28.

No party has contested the fact that MPE Energy falls squarely within the category of an export from the ISO Control Area and receives the benefits from the CAS performed by the ISO. The Initial Decision was of this opinion, as well, and found:

> MPE both contributes to CAS costs incurred by the ISO and receives 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. MPE is clearly an export within the definition of the ISO proposed billing determinant for CAS charges and nothing in the record persuades me that MPE should be exempted from paying its fair share of the CAS charge. In fact, to do so would result in inappropriate cost shifting to other market participants by increasing their share of CAS charges.

99 FERC at 65,133 (footnote omitted). 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.[44] The ISO's responsibility as Control Area operator simply allows no exception for MPE.

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[44] As the Initial Decision noted:

> 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

SCE admits that MPE benefits from the services provided by the ISO. SCE BOE at 28. Nonetheless, SCE argues that given what it considers MPE's lower level of benefits from the ISO's CAS than that derived by other entities, and since MPE must be assessed either all or none of the CAS Charge, the more equitable policy would be to assess MPE none. *Id.* The ISO acknowledges that CAS may benefit different entities to different degrees. Tr. 1955:5 - 1957:18. As the Initial Decision found, however, that the degree of benefits is not determinative:

> [c]ost *causation* is not necessarily the same thing as cost *benefit*. Thus, the fact that all load causes the ISO to incur administrative costs as reflected in the CAS may nevertheless support recovery of those costs based on all Control Area Gross Load plus exports even assuming arguendo that variable levels of use result in variable levels of benefits.

99 FERC at 65,086.

In the ISO's view, asking for a more graduated payment scale, as SCE seems to be doing, is really asking for additional service categories beyond the three proposed in this initial unbundling effort. As the Initial Decision found with regard to the Southwest Power Link:

> The fact that SWPL Energy 's contribution to costs incurred and benefits received from CAS may be less that those of other market participants who are interconnected with the ISO Controlled Grid simply underscores the need for further unbundling of the CAS component of the GMC. While this should be of the highest priority in a full stakeholder review process in 2003, the fact that the current CAS charge is not "granulated" to a greater degree does not negate the fact that all load and exports in the ISO's Control Area, even "wheeling through" load, contributes to CAS costs incurred by the ISO and receives benefits from the CAS performed by the ISO.

> ISO must consider the entire output of the Mohave Plant, not just that element owned by Edison, 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.

99 FERC at 65,133, n. 125.

99 FERC at 65,135.

Additional service categories may well be appropriate in the future. *See, e.g.*, Tr. 1537:21 - 1538:2. As previously discussed, The ISO need not show that the current proposal is the best possible, however -- it need only show that *this* proposal is just and reasonable. Moreover, even this first step is a significant improvement from the bundled GMC. *See, e.g.*, Ex. 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 that benefit from the ISO's services, and it avoids a cost-shift to entities that already bear their fair allocation of CAS Charges. 99 FERC at 65,133.

SCE also argues that since MPE is not assessed the transmission Access Charge, it should not be assessed the CAS Charge, since "Control Area Services tasks...are largely related to the operation of the underlying transmission facilities." SCE BOE at 29. This argument ignores the fact that the Access Charge and the CAS Charge are unrelated to one another, and are assessed on completely different bases. As defined in the ISO Tariff, the Access Charge is collected from Market Participants to pay the Commission-approved Transmission Revenue Requirement ("TRR") of the Participating TOs. Thus the ISO only collects the TRR for SCE, based on the rate the Commission determined was just and reasonable for SCE's revenue requirement. The Access Charge has nothing to do with operation of the transmission line, its impact on the ISO Control Area or how the ISO is reimbursed for its operating costs. The CAS Charge, as described in section VI.F, *supra*, is applied to Scheduling Coordinators and other appropriate parties based on Control Area Gross Load and exports to reimburse the ISO for the costs it incurs, not for the revenue requirement of the transmission owner. Thus it is apparent that there is no linkage between these different charges, and an exemption from one is no basis for an exemption from the other.

Finally, SCE argues that since the loads served by MPE are located in other Control Areas, they are likely to be double-charged for Control Area Services. SCE BOE at 29. As a threshold matter, there is no evidence in the record as to what, if anything, other Control Areas charge MPE. More importantly, however, it is not possible for any charges assessed by other Control Areas to play a part in recovering costs incurred by the ISO, which is the purpose of the CAS Charge. What other Control Areas may or may not do has no bearing on the ISO's right to recover legitimately incurred costs from exported Energy that causes or benefits from the ISO's activities.

SCE's proposed "remedy" to "correct" the Initial Decision's support for assessing the CAS Charge on MPE is that "[t]he definition of exports should exclude exports that are not the Load Responsibility of the ISO and which are exported over transmission facilities that were not turned over to the ISO's Operational Control" (SCE BOE at 29). Since, as demonstrated above, the MPE facilities have, in fact, been turned over to the ISO's Operational Control, even if the Commission should grant the "remedy" sought by SCE, this would not allow MPE to avoid its proper share of the CAS Charge.

Therefore, the Initial Decision was correct in finding the assessment of the CAS Charge on MPE to be just and reasonable.

J. The Initial Decision Was Correct in Finding It Just and Reasonable to Assess the Grid Management Charge on SWPL Energy [Section I-H of the Initial Decision]

The Initial Decision found it just and reasonable to assess the GMC on Energy schedules that SDG&E coordinates over the Southwest Power Link ("SWPL") on behalf of Arizona Public Service Corporation ("APS") and Imperial Irrigation District ("IID"), the other joint participants in the SWPL facilities. These schedules are referred to as "SWPL Energy." *See* 99 FERC at 65,135.

San Diego Gas & Electric Company ("SDG&E") takes exception to the Initial Decision's ruling that it is just and reasonable to assess elements of the Grid Management Charge on SWPL Energy. SDG&E has stated several exceptions to the Initial Decision's ruling, but the support provided for these exceptions does not withstand examination.

1. SDG&E Is Incorrect in Arguing that the Commission's Order on the ISO's Proposed Amendment No. 2 to Its Tariff Dictates that the GMC Cannot Be Assessed on SWPL Energy.

a. The ISO's Application of the GMC to SWPL Energy Did Not Contravene the Commission's Amendment No. 2 Decision.

This issue is discussed in section VI.F, *supra*.

b. The ISO Has Operational Control over the APS and IID Shares of SWPL, and these Shares Are a Part of the ISO Controlled Grid.

The Initial Decision correctly found that whether transmission facilities are under ISO Operational Control is immaterial to assessing the GMC. 99 FERC at 65,136.

Regardless of whether the non-SDG&E portions of SWPL are considered part of the ISO Controlled Grid, it is still appropriate to assess them elements of the GMC. The CAS Charge, as described above, is assessed based on Control Area Gross Load and exports from the Control Area. SWPL Energy is a Wheel Through, which means it is one part import and one part export. Tr. 644. Therefore, as was the case with MPE, it is not unreasonable to assess the export portion of the transaction a share of the CAS Charge, regardless of whether SWPL is considered a part of the ISO Controlled Grid. 99 FERC at 65,134.

As the Initial Decision found, whether SWPL transmission facilities are, or are not, a part of the ISO Controlled Grid is not material to whether these facilities may be assessed the Market Operations ("MO") Charge. 99 FERC at 65,136. Transactions assessed the MO charge ". . . are not limited to transactions using the ISO Controlled Grid." ISO-34 at 17:14-

18:2. The MO charge is assessed to ". . . total purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy." ISO Tariff (Ex. J-2) § 8.3.3. In this case, the MO Charge is assessed on small purchases of Imbalance Energy needed to replace line losses on SWPL Energy in the ISO Control Area.

As was the case with SCE on behalf of Mohave Participant Energy, SDG&E argues that the APS and IID shares of SWPL are not part of the ISO Controlled Grid. SDG&E BOE at 27. Further, SDG&E states, in rather an attenuated manner, that "if Amendment No. 2 governs this case,[45] then it applies to bar GMC to the APS and IID SWPL schedules *if* their respective portions of SWPL are not part of the ISO Controlled Grid." *Id.* (emphasis in original). SDG&E is wrong on all counts: the order on Amendment No. 2 does not govern this case (as described above in section VI.F), the respective portions of SWPL owned by APS and IID SWPL are part of the ISO Controlled Grid, and even if they were not, it is still appropriate to assess elements of the GMC on SWPL Energy.

If the Commission should disagree with the Initial Decision's finding on this issue, and find that whether SWPL Energy facilities are a part of the ISO Controlled Grid is a significant point in assessment of the GMC, the ISO's testimony and exhibits demonstrate that the non-SDG&E elements of SWPL are indeed part of the ISO Controlled Grid. SWPL Energy uses facilities that are under the ISO's Operational Control and therefore, are included within the ISO's Controlled Grid. Ex. ISO-36 at 6:11-14. As was the case with MPE, the SWPL facilities were turned over to ISO Operational Control through a proper Section 203 filing. *Pacific Gas & Electric Company, et al.*, 81 FERC ¶ 61,122 (1997). As part of the Section 203 filing, SDG&E included the SWPL in Appendix A of the Transmission Control

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[45] Presumably this is intended to mean if the *order* on Amendment No. 2 governs this case.

Agreement, which expressly states that the transmission line is under the ISO's Operational Control. Ex. J-10; Tr. 1868. *See also* Tr.1824 (Le Vine). As noted above with regard to MPE above, the Section 203 filing necessarily transferred Operational Control over the complete SWPL facilities, since 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. Ex. ISO-36 at 5:4-16.[46]

Finally, SDG&E's reliance on the terms of the 1998 GMC Settlement (SDG&E BOE at 31-33) is misplaced. *See* section VI.F, *supra*, regarding the Settlement's lack of precedential value.

2. Application of The Market Operations Charge to SWPL Energy Is Not Unduly Discriminatory

The MO Charge is intended to recover the costs of operating the ISO's markets and settlement-related costs. *See* ISO Tariff (Ex. J-2) First Revised Sheet No. 333. The ISO's markets include its Imbalance Energy Market. 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 Energy leaves the ISO Control Area.[47] To the extent that schedules require the ISO to provide Imbalance Energy because the SC for the transactions did not provide for losses, the administrative costs asso-

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[46] With regard to SDG&E's arguments about what "Operational Control" actually means, ISO witness Deane Lyon explained that Operational Control does not mean the ISO may do whatever it wants with a line, but is limited to certain limited operations. Tr. 1234-35; 1248.

[47] If 100 MW is put into the system at A, and there are 13 MW lost between points 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. Ex. ISO-36 at 15:17-20; Tr. 1903:2-17. This can be self provided or procured through the ISO's Imbalance Energy market.

ciated with such provision are recovered through the MO Charge.[48] *See* ISO Tariff (Ex. J-2) Proposed Section 8.3.3.

As noted by ISO witness Deborah Le Vine in her Rebuttal Testimony:

> Like any other purchaser or seller of Imbalance Energy SWPL Energy contributes to the ISO's costs of market and settlement related services. The services that the ISO performs for such entities include providing open and non-discriminatory access to market activities for participants through the provision of Energy balancing services; posting market information; market surveillance and analysis; settlement, billing, and metering including using information from Day-Ahead scheduling, Hour-Ahead scheduling, and real time operations, Market Clearing Prices, bid prices, Ex Post Prices, and metered information from Generators, Loads, and inter-tie points, ultimately to balance the billing of and payments for energy, capacity and transmission service into, through, and out of the ISO control Area through Scheduling Coordinators.

Ex. ISO-34 at 16:15 – 17:3.

Other entities whose schedules result in Imbalance Energy costs associated with losses also are assessed the MO Charge. That SWPL is a joint ownership facility has no bearing on this issue. Thus, as the Initial Decision found, it is just and reasonable for SWPL Energy schedules to be assessed a share of the MO Charge when Imbalance Energy is procured to cover losses. 99 FERC at 65,136.

SDG&E also claims that the ISO "ignores the. . . reciprocal nature of Control Area services and coordination of schedules." SDG&E BOE at 34. What SDG&E fails to understand is that what other Control Areas may or may not do has no bearing on whether the ISO is correct to recover its costs from the entities that cause them to be incurred, and which benefit from services performed by the ISO.[49]

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48 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* Ex. 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)."

49 99 FERC at 65,135. SDG&E argues that APS and IID do not benefit from the ISO's services with regard to SWPL Energy. SDG&E BOE at 36. SDG&E argues that the imbalances with regard to these sched-

3. Assessing The CAS Charge on SWPL Energy Is Appropriate

a. The ISO Sought to Apply the CAS Charge to SWPL Energy in the Event that the Initial Decision Determined that SWPL Energy Was Similarly Situated to Mohave Participant Energy.

SDG&E argues that the issue of whether to assess the CAS Charge on SWPL Energy "was not set for hearing." SDG&E BOE at 38. On the contrary, the entire unbundled GMC was set for hearing in this proceeding. *California Ind. Sys. Oper. Corp.*, 93 FERC ¶ 61,337 (2000). Moreover, included as item I.H in the Joint Stipulation of issues (Ex. J-1) was "Is it just and reasonable to assess components of the GMC on SWPL Energy?" It hardly could be stated more plainly.

SDG&E also is incorrect in contending that the ISO did not seek to apply the CAS Charge on SWPL Energy in this proceeding, and that "no party advocated such application until initial briefing." SDG&E BOE at 18. In fact, as noted in the passage from the Initial Decision quoted above, ISO witness Deborah Le Vine called for such assessment in her Rebuttal Testimony, in the event that the judge decided that SWPL Energy and MPE were similarly situated. Ex. ISO-36 at 9. Moreover, as SDG&E notes (SDG&E BOE at 18), SCE also called for the assessment of the CAS Charge on SWPL Energy should MPE be so assessed. SCE I.B. at 42. Thus it was appropriate for the Initial Decision to find that, since undue discrimination was present, SWPL Energy should be assessed the CAS Charge.

ules is very small. *Id.* at 36-37. As described above, however, the ISO does provide SWPL Energy with certain Imbalance Energy, and it is appropriate that the costs of this be recovered through the Market Operations Charge. 99 FERC at 65,136.

b. The Billing Determinant for the CAS Charge Is Applicable to SWPL Energy

As noted in section VI.F, *supra*, the CAS Charge is based on Control Area Gross Load and *exports*, and not merely on Control Area Gross Load, as SDG&E appears to believe. SDG&E BOE at 40. That being the case, it is irrelevant that APS and IID do not serve Load in the ISO Control Area. SDG&E BOE at 18. The Initial Decision found that the assessment of CAS on exports was appropriate. 99 FERC at 65,133. Since SWPL Energy is wheeled through, it is considered one part import and one part export. Tr. 644. Moreover, as Ms. Le Vine stated on the stand, the ISO assesses other wheeled through transactions the CAS Charge. Tr. 1812:16-20.

c. The Initial Decision Does Not Apply the CAS Charge Retroactively

Probably the most unfortunate aspect of the SDG&E BOE is its repeated, erroneous, complaint that the Initial Decision applied the CAS Charge to SDG&E retroactively for 2001.[50] SDG&E has misconstrued the Initial Decision's ruling with regard to the applicability of the CAS Charge to SWPL Energy. A careful reading of the Initial Decision demonstrates that no retroactive application is intended.

The pertinent section of the Initial Decision states:

> I concur [with the rebuttal testimony of ISO witness Deborah Le Vine] that my determination that SWPL and MPE are similarly situated for purposes of allocation of the CAS charge requires, in fairness to all other market participants, that both be assessed the CAS charge. However, given . . . the unrefuted fact that *the ISO has granted SWPL an exemption from the CAS charge for 2001*, this ruling should be prospective only, i.e., applied in 2002 and forward, as to MPE.

50 *See, e.g.*, SDG&E BOE at 39.

99 FERC at 65,135 (emphasis added). It is clear from this passage that the Initial Decision's intention with regard to SWPL Energy is to honor the ISO's 2001 exemption of SWPL Energy from the CAS Charge. Therefore, SDG&E's arguments regarding the alleged retroactivity of the assessment of this charge on SWPL Energy are inapposite.

4. Policy Considerations Do Not Dictate Exempting SWPL Energy From The GMC

SDG&E mentions four "policy considerations" that it claims "support Commission review of the Initial Decision." SDG&E BOE at 18. None of the reasons discussed by SDG&E under this heading, however, warrant a reexamination of the Initial Decision's findings.

a. <u>The GMC Does Not Discourage RTO Formation</u>

SDG&E contends that by applying the GMC "beyond the grid conveyed to its control", the ISO is "creating perverse disincentives to [Regional Transmission Operator] formation." *Id.* SDG&E argues such "beyond the grid" application will lead to reciprocal charges being imposed by other Control Areas. *Id.* With regard to the Market Operations Charge, the ISO naturally assesses the charge on entities outside of the ISO Controlled Grid, to the extent that they participate in the markets operated by the ISO. *See* Exh. ISO-34 at 16. To the extent that an entity outside the ISO Controlled Grid does not care to incur the Market Operations Charge, it merely has to avoid participation in the ISO's markets. It is hard to imagine how the prospect of being reimbursed for the costs of operating markets by those that participate in those markets could in any way discourage entities from forming RTOs.

With regard to the CAS Charge, as described above, the ISO does not consider SWPL Energy to be "beyond the grid conveyed to its control." SDG&E BOE at 18. Moreover, vague concerns about the possibility of retaliatory reciprocal charges raining down from other Control Areas should not dissuade the Commission from allowing the ISO to recover the costs of its services from those entities that benefit from these services and cause these costs to be incurred. Indeed, one would imagine that the prospect of recovering their costs in such a manner would *encourage* other Control Areas to form RTOs, if they could not recover their reasonably incurred costs from those who caused them to be incurred in any other manner.

b. The Initial Decision Has Dealt Appropriately with the Burden Of Proof

SDG&E claims that the ISO's burden of proof in this proceeding is somehow undermined because the Initial Decision has allowed the ISO to assess the GMC on what SDG&E considers non-grid transactions, despite what SDG&E considers to be the absence of any indication that such would be the case in the ISO's filing. SDG&E BOE at 18-19. With regard to the Market Operations Charge, it is neither novel nor against Commission precedent for an entity to assess charges for participation in markets it operates. As explained above, the Market Operations Charge is assessed on non-ISO Controlled Grid transactions only to the extent that they implicate the markets operated by the ISO.

With regard to the CAS Charge, as described above in section VI.F, this charge is based on Control Area Gross Load and exports. This billing determinant was spelled out clearly in the initial GMC 2001 filing; in no way was it sprung on parties as a surprise. Ex. ISO-5 at 6; *see also* Ex. J-2, First Revised Sheet No. 217.

SDG&E also claims that since the ISO did not address the Amendment 2 order, and yet in the Initial Decision received "precisely the result" rejected in that order, the burden of proof was not honored in this proceeding. SDG&E at 18-19. The order on Amendment No. 2 is discussed in section VI.F.1, *supra*. It bears repeating, however, that the order on

Amendment No. 2 in no way forecloses the ISO's collecting the GMC as it proposed in this proceeding, nor does it contradict the Initial Decision in any way.

c. The Initial Decision Does Not Apply the CAS Charge to SWPL Energy Retroactively

SDG&E claims that, despite such public policy concerns as notice and fairness, the Initial Decision applies the CAS Charge to SDG&E retroactively for 2001. SDG&E BOE at 19. As described above, this simply is not the case.

d. The ISO Has Not Sought Inappropriately to Spread the Recovery of Its Costs

SDG&E claims that the ISO has applied its Grid Management Charge beyond the ISO Controlled Grid in order to spread those costs as a result of some unspecified "political imperative". SDGE BOE at 19-20. On the contrary, the record in this proceeding demonstrates that the ISO has sought to recover its costs by assessing appropriate charges on the entities that cause these costs to be incurred, and that benefit from the services that result in these costs. *See, e.g.*, Ex. ISO-1 at 22; Ex. ISO-21 at 29-30; Ex. S-6 at 5; DWR-1 at 13; DWR-2 at 2. As the Initial Decision has found,

> Cost causation principles require only that rates match costs to serve classes of customers and individual customers "as closely as practicable," not that they do so perfectly. *See Alabama Elec. Coop., Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982). On balance, it is my determination that the ISO's proposal, while not perfect, is just and reasonable at this time.

99 FERC at 65,086 (footnote omitted).

K. The Initial Decision Was Correct in Allowing the GMC to Be Charged to Other Appropriate Parties [Section I.I of the Initial Decision]

The Initial Decision was correct to find it just and reasonable to direct bills to "other appropriate parties" in the form of Load Serving Entities based on their Control Area Gross Load, regardless of their contractual relationship, or lack thereof, with the ISO, and that GEs fall into this category "to the extent that these entities continue to benefit from and contribute to the cost of the CAS, including CAS system planning, maintenance, coordination, reliability, and safety, by remaining electrically connected to the Grid." 99 FERC at 65,141. *See also* Ex. ISO-27 at 10-11. The Initial Decision further required the ISO to make a compliance filing to define the term "other appropriate party" and set forth the procedure by which these entities will be billed the GMC in the ISO Tariff. 99 FERC at 65,141.

The ISO developed the mechanism of "other appropriate party" to allow it to bill entities other than Scheduling Coordinators their proper share of the MO Charge and the CAS Charge elements of the GMC. As described in the Rebuttal Testimony of ISO witness Michael Epstein,

> The ISO developed the concept of "other appropriate parties" because a number of entities that are provided services or participate in the ISO's markets (including OOM transactions) other than directly through SCs either (1) are GEs with Load in the ISO Control Area for which the ISO provides Control Area Services, or (2) participate in the ISO's markets (including OOM transactions) as either buyers or sellers of Energy and Ancillary Services and thus are suitable to be charged the Market Operations Charge.

Ex. ISO-27 at 8:14-20.

TANC[51] complains that the ISO "seeks to charge entities with which it has no privity of contract for costs which such entities do not agree to bear." TANC BOE at 31. SMUD likewise contends that the ISO lacks a contractual basis to assess other appropriate parties.[52] SMUD BOE at 55. The Initial Decision correctly finds this argument unpersuasive with regard to entities that have benefited from the Control Area Services and have contributed to

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51 TANC's arguments on this issue are adopted by MID.

52 SMUD alleges that the ISO's inability to charge entities with which it does not have a contractual relationship arises out of the order on Amendment No. 2. SMUD BOE at 56-58. The result in Amendment No. 2 is not a bar from assessing these entities, as discussed in section VI.F.1, *supra*.

the costs of performing these services. 99 FERC at 65,141. This argument is discussed in Section M.

TANC also argues that the result of the Initial Decision will lead to "chaos". SMUD contends that approving the use of the term "will give the ISO a carte blanche, self-executing Tariff provision." SMUD BOE at 57. On the contrary, the Initial Decision would require the ISO to make a compliance filing precisely spelling out the parameters of the "other appropriate parties" concept:

> [T]he ISO must be required to make a compliance filing to specifically define the term "other appropriate parties" as clarified by the ISO in this proceeding to its Master Definition section of the Tariff and must be required to file factual and legal support for its GMC charges to the affected parties. In addition, the compliance filing should include modifications that incorporate into the ISO Tariff procedures and protocols for billing to "other appropriate parties" the CAS and MO charges of the GMC. Further, the compliance filing should clarify that only the CAS and MO charges will be assessed to "other appropriate parties" as specifically defined for each GMC component and that there are no "other appropriate parties" that will be assessed the IZS charge. Exh. S-6 at 39-42. Additionally, the ISO must make a compliance filing to explain how excess funds will be refunded with an unbundled GMC. Exh. S-6 at 39-42. (Pointer).

99 FERC at 65,141. It is clear from this that the application of the term "other appropriate parties", far from being an "invitation to chaos" (TANC BOE at 32), will actually become more precise if the Initial Decision is sustained by the Commission. Moreover, there is nothing "self-executing" about a provision that will be filed with the Commission with greater detail, and indeed approved by the Commission if it is found to be acceptable.

To the extent that parties are arguing that the GEs should not be assessed the GMC at all, and not about how they will be billed as "other appropriate parties" (*see* TANC BOE at 31; SMUD BOE at 57), this issue is discussed in section M, infra.

L. The Initial Decision Properly Found That Control Area Services Charges Allocated To Behind-The-Meter Loads Served By Qualifying Facilities Should Be Billed Directly To Those Loads [Section I.J.1 of Initial Decision]

In its Initial and Reply Briefs, the ISO argued that CAS charges for behind the meter Load served by QFs should be billed to the UDC that schedules standby service for that Load. The ISO noted that 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. The ISO argued that, 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 M, 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 SCE would be billed for Imbalance Energy to meet QF Load in excess of scheduled Standby Service, and would pass the cost on). Rather, the ISO contended that the responsibilities of a SC extend to paying charges in accordance with the ISO Tariff, ISO Tariff (Exh. 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 .

The ISO pointed out that, 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.[53] 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 an SC Metered Entity for which it is responsible, not simply for the net Load.

Thus, the ISO argued, it further follows that a UDC that serves as an 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[54] to provide reliable service to entities within its service territory that require service, *see, e.g., Pinney & Boyle Co. v. Los Angeles Gas & Elec. Corp.*, 141 P. 620 (1914), including behind-the-meter Loads. CAS charges are part of the cost that the UDC pays to obtain the reliability that it must provide.

The Initial Decision rejected the ISO's argument. 99 FERC at 65,143. It concluded that the ISO should in the first place bill the Loads served by QFs directly, and that the ISO

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[53] 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.

should bill the UDCs only if the Commission finds that there are statutory, regulatory, or jurisdictional impediments to direct billing.

CCC takes exception to the Initial Decision in this regard. It contends that the ISO lacks the contractual privity with the QFs that it contends is necessary for direct billing. CCC BOE at 17-29. This deficiency, however, is easily resolved. If the Commission agrees with the Initial Decision that the behind-the-meter Loads served by QFs are taking CAS from the ISO in connection with their internal loads, but also agrees with the Initial Decision that the ISO should not bill the UDCs for those CAS, then the Commission should direct the ISO to develop appropriate agreements to provide the necessary contractual privity. The Commission should also authorize the ISO, if the Loads served by QFs wish to remain interconnected with the ISO Controlled Grid but refuse to enter into the necessary agreement, to file appropriate unexecuted agreements.

CCC also contends that the Commission's decision would not provide a sufficient basis for billing the Loads served by QFs because they are retail Loads, and their rates are under the jurisdiction of the CPUC. CCC BOE at 29. The Commission, however, has jurisdiction over unbundled retail transmission. *New York v. FERC*, 122 S.Ct. 1210 (2002). CAS charges, which reflect the costs of maintaining the reliability of the transmission grid, are transmission costs. For example, SCE has argued that CAS were formerly included in SCE's transmission revenue requirement. Accordingly, the Commission has jurisdiction over CAS charges to Load served by QFs.

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[54] The ISO Tariff defines a UDC as an entity that owns a Distribution System and, *inter alia*, "provides regulated retail electric service." ISO Tariff (Exh. J-2) at Appendix A.

M. The Initial Decision Properly Found That Control Area Services Charges Allocated To Governmental Entities Internal Load Should Be Billed Directly To The Governmental Entities [Section I.J.3 of the Initial Decision]

In its Initial and Reply Briefs, the ISO argued that – absent an agreement by the GE to be charged as an "other appropriate party" – CAS charges for GE's internal Load should be billed to the entity that is acting as a Scheduling Coordinator for the GE. The ISO noted that entities, such as PG&E and SCE, that schedule on the ISO Controlled Grid in accordance with existing transmission contracts or Interconnection Agreements have entered into an 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 an 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 responsibilities 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, the ISO noted that nothing inherent in the role of an SC suggests that the RPTO's responsibility extends only to scheduled Load. Under the ISO Tariff, the first identified responsibility of an 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 ISO argued that 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 ISO urged the Presiding Judge to 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.

The Initial Decision rejected the ISO's argument. 99 FERC at 65,146. It concluded that the ISO should bill the GEs directly and should make appropriate filings to provide any necessary authority.

SMUD, TANC, and MID take exception to the Initial Decision in this regard. They contend that the ISO lacks the contractual privity with the GEs necessary for direct billing. This deficiency, however, is easily resolved. SMUD BOE at 56-58; TANC BOE at 30-32; MID BOE at 19. If the Commission agrees with the Initial Decision that the GEs are taking CAS from the ISO in connection with their internal loads, but also agrees with the Initial Decision that the ISO should not bill the SCs for those CAS, then the Commission should direct the ISO to develop appropriate agreements to provide the necessary contractual privity. The Commission should also direct the ISO, if the GEs wish to remain interconnected with the ISO Controlled Grid but refuse to enter into the necessary agreements, to file appropriate unexecuted agreements.

N. The Initial Decision Resolved The Issues Raised By BART In A Just And Reasonable Manner [Section I.K of the Initial Brief]

1. The Initial Decision's Finding That BART Benefits From Market Operations Is Correct

The Initial Decision states that "PG&E and the ISO are undoubtedly correct in observing that BART benefits from MO because its energy could not be scheduled without MO…" 99 FERC at 65,148. BART excepts to this statement, arguing that it is "undisputed that the MO function is neither necessary nor beneficial to BART." BART BOE at 19. That is not the case.

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.

2. The Initial Decision Correctly Found That The ISO's Activities And Costs Accounted For Under The Control Area Services Charge Are Essential And Beneficial To BART

The Initial Decision found that "it is just and reasonable that BART pay its fair share of the ISO's CAS charges and nothing in its [contract] with PG&E supports a different conclusion." 99 FERC at 65,149.

BART argues that the cost of any activities in which the ISO engages that are not "essential or beneficial to the provision of transmission service to BART," should not be borne by BART. BART BOE at 21. The ISO has demonstrated, however, that all Load in the Control Area benefits from the ISO's activities, and causes the costs to perform these activities to be incurred. *See* section VI.F, supra. As the Initial Decision found, there is no reason to exclude BART from this responsibility. 99 FERC at 65,149.

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.

O. The Initial Decision Was Correct To Determine That The Issue Of Cost Control Measures Is Moot, And That The Additional Cost Control Measures Proposed By Other Parties Have Not Been Supported [Section I.L of the Initial Decision]

The Initial Decision found that the additional measures for controlling the ISO's costs suggested by certain parties were not

> persuasively supported in terms of a cost/benefits analysis assessing potential costs associated with implementation as compared to benefits which may reasonably be expected to be realized from such implementation.

99 FERC at 65,151 (footnote omitted). As well, the Initial Decision stated that the issue is mooted by virtue of the fact that the ISO has made a 205 filing for 2002. 99 FERC at 65,151.

The ISO has demonstrated that reasonable and effective incentives to control costs exist currently. 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, 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 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 B 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.

Moreover, in the context of a section 205 filing, the ISO's revenue requirement must be approved by the Commission. The ISO made section 205 filings for the GMC for 2001 and 2002. Because the ISO has made the Section 205 filing for 2002, the Initial Decision is correct to consider the issue of further cost control measures moot. 99 FERC at 65,151.

TANC expresses concern that without proper cost control measure, including specific detail regarding the ISO's tasks, parties will not be able to determine whether or not the allocation of the GMC is just and reasonable. TANC BOE at 46. The ISO considers its GMC filing to contain sufficient information for Market Participants to understand how the GMC is allocated. *See*, e.g., Exh. ISO-7. Should the parties desire additional information, that can be provided through the discovery process in the section 205 proceeding or through more informal meetings with ISO personnel ready to explain any confusing elements of the GMC allocation.

VII. CONCLUSION

WHEREFORE, for the reasons discussed above, the Commission should reject the exceptions of the parties described above.

Respectfully Submitted,

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Dated: July 1, 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 1st Day of July, 2002.

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