103 FERC ¶ 61,114

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 463

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

OPINION AND ORDER ON INITIAL DECISION

Issued: May 2, 2003

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APPEARANCES

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, and Nora Mead Brownell.

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OPINION NO. 463

OPINION AND ORDER ON INITIAL DECISION

(Issued May 2, 2003)

Introduction

1. This case is before the Commission on review of an Initial Decision issued on May 10, 2002.[1] The Initial Decision resolved a number of issues arising from (1) the filing by the California Independent System Operator Corporation (ISO) of its unbundled grid management charge (GMC) for 2001, intended to allow the ISO to recover its administrative and operating costs; and (2) the filing by Pacific Gas and Electric Company (PG&E), of its proposed GMC Pass-Through Tariff (PTT), designed to pass through these GMC charges to certain of its wholesale contract customers.

2. The Initial Decision generally upheld both the ISO's proposed GMC and PG&E's PTT as just and reasonable. The Commission largely affirms the Initial Decision, but reverses it on two issues: (1) the allocation of Control Area Service (CAS) costs to behind-the-meter generation; and (2) the passthrough by PG&E of the Market Operations component of the GMC. Our decision benefits customers by appropriately allocating the ISO's costs among its customers and preventing the trapping of these costs downstream.

[1] California Independent System Operator Corporation, et al., 99 FERC ¶ 63,020 (2002).

Background

3. On November 1, 2000, as amended on December 15, 2000, the ISO submitted to the Commission its proposed unbundled GMC for 2001. The ISO proposed to charge the GMC to all of its Scheduling Coordinators (SCs), including PG&E. On November 13, 2000, as amended on December 26, 2000, PG&E submitted its proposed PTT. PG&E's PTT would allow it to passthrough the GMC charged by the ISO to applicable wholesale Control Area Agreement (CAA) customers for which PG&E acts as a SC. On December 29, 2001, the Commission issued an order which accepted the GMC and the PTT, as amended, suspended them for a nominal period to become effective January 1, 2001, subject to refund, and set them for hearing.[2]

4. The presiding judge conducted a hearing in these proceedings from November 13, 2001, until December 20, 2001. The active parties included the ISO, PG&E, Southern California Edison (Edison), San Diego Gas & Electric (SDG&E), the San Francisco Bay Areas Rapid Transit District (BART), California Department of Water Resources (DWR), City and County of San Francisco (San Francisco), Cogeneration Association of California and the Energy Producers and Users Coalition (CAC/EPUC), Transmission Agency of Northern California (TANC), Modesto Irrigation District (Modesto), Northern California Power Agency (NCPA), Sacramento Municipal Utility District (SMUD), Silicon Valley Power (SVP), the Western Area Power Administration (WAPA), the California Public Utilities Commission (CPUC), and Commission trial staff (Staff).

5. The California Cogeneration Council (CCC) filed a petition to intervene out-of-time accompanied by its brief on exceptions, as did a group designating itself as the Customer Generators (CG).[3]

6. Of the issues resolved by the Initial Decision and raised on exceptions, we address the following: (1) the incentive compensation budget refund; (2) the unbundling of the GMC into three service categories; (3) the assessment of the Control Area Service charge based on control area gross load; (4) the assessment of the charge to retail behind-the-

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[2]California Independent System Operator Corporation, et al., 93 FERC ¶ 61,337 (2000).

[3]This group consists of the Electricity Consumers Resource Council, the United States Combined Heat and Power Association, the American Chemistry Council, the American Iron and Steel Institute, the American Forest & Paper Association, the American Petroleum Institute, the National Petrochemical & Refiners Association, the Fertilizer Institute, and the Chemical Industry Council of California.

meter load; (5) the assessment by the ISO of the GMC to "other appropriate parties"; (6) whether PG&E's PTT passes through the costs of a new service providing new benefits to the CAA customers; and (7) whether PG&E's PTT is consistent with cost causation principles.

7. As to the remaining issues raised on exceptions, the Commission finds, having reviewed the record, the Initial Decision, and the parties' briefs, that they were properly resolved by the Initial Decision. We therefore deny the exceptions and summarily affirm and adopt the findings by the presiding judge that (1) the ISO's proposed GMC revenue requirement for 2001 was just and reasonable (with one exception discussed below); (2) the ISO's proposed GMC allocation for 2001 was just and reasonable. Any issues not specifically referenced in this opinion are likewise affirmed.

Discussion

A. Procedural Issues

8. The Commission's Rules of Practice and Procedure require that entities seeking late intervention in a Commission proceeding must demonstrate good cause warranting such action.[4] We have routinely denied motions to intervene in a proceeding in order to prevent "unjustified delay and disruption of the proceeding," and "an undue burden on other parties."[5] We will deny the petitions for late intervention. Neither CCC nor CG have alleged any extraordinary circumstances which would warrant granting their untimely motions to intervene at this late date (after the hearing, the close of the record, and the issuance of the Initial Decision).

B. ISO issues (ER01-313-000, et al.)

1. Incentive Compensation Budget Refund

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[4] 18 C.F.R. §§ 385.214(b)(3), 385.214(d)(1) (2001).

[5] Southern Company Services, Inc., 96 FERC ¶ 61,168 at 61,758 & n.5 (2001), citing 18 C.F.R. §§ 385.214(d)(1)(ii), 385.214(d)(1)(iv) (2001); accord, ISO New England, 90 FERC ¶ 61,053 at 61,224 (2000); PJM Interconnection, L.L.C., 88 FERC ¶ 61,039 (1999). See generally, Power Company of America v. FERC, 245 F.3d 839, 843 (D.C. Cir. 2001); City of Orville, Ohio v. FERC, 147 F.3d 979, 988-992 (D.C. Cir. 1998).

9. While the Commission summarily affirms the Initial Decision concerning the ISO's GMC revenue requirement, we must address one aspect of this issue. The ISO conceded that, due to an error, it had budgeted $1,834,267 too much for incentive compensation. The judge therefore determined that this amount should not be included in the ISO's rates. However, she did not decide whether a refund of the excess was appropriate, regarding this as "a policy question that is more appropriately addressed by the Commission."[6]

10. On exceptions, the ISO states that it has already credited any overcollected funds "back to market participants by reducing the 2002 GMC revenue requirement," so that an order of refunds "would result in the ISO's failure to recover its costs."[7] The ISO further maintains that because it is a non-profit structure without any shareholder capital or rate base returns from which to make refunds, any refund the Commission might order of the GMC "would ultimately be funded by the very ratepayers receiving the refund."[8] Thus, the ISO requests the Commission to allow it to employ a crediting mechanism of its financial operating reserve in lieu of traditional refunds. Taking the opposite position, TANC asserts that actual refunds are the "only proper method" for curbing unreasonable cost estimates by the ISO under the Commission's "established refund policies and procedures."[9]

11. The Commission finds that the ISO should refund the amount in question. Our practice "has been to order full refunds of any amounts collected above the just and reasonable level, absent contrary equitable considerations."[10] The California ISO has not made a persuasive case that its admittedly erroneous overcollection should not be refunded to its customers. We do not agree that the ISO's non-profit status should preserve it from making a refund of the amount involved under the circumstances presented. Finally, we believe that this finding is consistent with the ISO's recent tariff

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[6] 99 FERC at 65,077.

[7] ISO Br. at 5 (citations omitted).

[8] Id. at 6.

[9] TANC Br. at 14 (citations omitted).

[10] San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services, etc., 97 FERC ¶ 61,275 at 62,185 & n.66, citing Western Resources, Inc. v. FERC, 9 F.3d 1568, 1581 (D.C. Cir. 1993).

change requiring refunds by Participating Transmission Owners (PTOs) rather than a reduction in the PTO's Transmission Revenue Balancing Account.[11]

2. Unbundling the GMC into Three Service Categories

12. As the Initial Decision explained, the ISO's unbundled GMC proposed to separate services into three categories: CAS, which includes the ISO's costs as control area operator, associated with ensuring reliable safe operation of the transmission grid and the entire control area; Inter-Zonal Scheduling (IZS), which includes the ISO's costs of administering congestion management, and the auction, monitoring and secondary market monitoring and scheduling of firm transmission rights; and Market Operations (MO), which includes the ISO's costs of market and settlement-related services.[12] Applying general cost causation principles that rates should match costs to serve classes of customers and individual customers "as closely as practicable," the judge concluded that "[o]n balance . . . the ISO's proposal, while not perfect, is just and reasonable at this time."[13] She agreed with the parties (including the ISO) that further unbundling of the CAS is appropriate, and directed that a "full stakeholder review of the GMC be conducted in 2003 for this purpose."[14] Having found the ISO proposal reasonable, the judge rejected an alternative plan proposed by Modesto witness Dr. Kirsch, but agreed with Trial Staff that it could be considered in the 2003 stakeholder process.

13. On exceptions, Modesto argues that the judge essentially conceded that the ISO's proposal was unreasonable, in that she called for the ISO to improve the methodology in the 2003 stakeholder process. The judge further erred, according to Modesto, by failing to recognized that Dr. Kirsch's alternate proposal was reasonable, in that it propounded a rate design for the GMC which actually allocated costs to the appropriate customers.

14. We affirm the judge's finding regarding the ISO's proposal to unbundle the GMC into three service categories.[15] Our examination of the record leads the Commission to

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[11]See California Independent System Operator Corporation, 100 FERC ¶ 61,209 (2002).

[12]99 FERC at 65,083.

[13]Id. at 65,086 (footnote omitted; emphasis in original).

[14]Id.

[15]To an extent, the exceptions on this issue also argue that the ISO has improperly
(continued...)

conclude that the ISO has reasonably unbundled the service categories so that they allocate costs to market participants based on the principles of cost causation. We note that the GMC rate structure is a work in progress, however, and that the ISO has continued to make refinements through the stakeholder process.[16] Nonetheless, the fact that the GMC is susceptible to further refinement does mean that it is not just and reasonable at this time.

15. The Commission rejects Modesto's contention that the judge erred by not adopting Dr. Kirsch's alternate proposal. At the very least, the record demonstrates that the proposal was incomplete.[17] Accordingly, we affirm the judge on this issue.

3. Assessment of CAS Charge Based on Control Area Gross Load

Amendment No. 2 Issue

16. The Initial Decision rejected the contention that the Commission's prior rejection in 1998 of an ISO proposal (Amendment No. 2)[18] foreclosed the application of the CAS Charge to non-grid transactions, and thus prohibited the allocation of the CAS Charge based on Control Area Gross Load (CAGL). In the judge's view, the Commission's rejection of Amendment No. 2 was not relevant, in that it involved extending the application of the ISO Tariff itself to non-grid transactions, while the instant case only applies the CAS Charge to such transactions. "More importantly," the judge concluded, the Commission's rejection of Amendment No. 2 "did not constitute a decision on the merits of the GMC assessment, but rather expressly reserved this issue for later determination."[19]

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[15](...continued)
allocated CAS costs based on control area gross loads. We deal with this issue in Section 3, below.

[16]Indeed, the ISO reports on its website that stakeholder meetings on the 2004 GMC rate structure began in October 2002.

[17]See Tr. 2656; Exh. S-6 at 31.

[18]California Independent System Operator Corporation, 82 FERC ¶ 61,312 at 62,241 (1998).

[19]99 FERC at 65,108-09 (emphasis in original).

17. Several parties take issue with the judge's conclusion, arguing that the Commission's decision rejecting the ISO's proposed Amendment No. 2 is controlling precedent here.[20] For example, SDG&E asserts that the Amendment No. 2 proposal was an attempt by the ISO "to extend its ability to charge GMC on transactions scheduled on facilities that are not part of the ISO Controlled Grid, but within the ISO control area."[21] By rejecting Amendment No. 2, SDG&E reasons, the Commission "necessarily rejected" the theory that SDG&E may be billed as SC for "non-ISO Controlled Grid energy schedules," which is the basis for the ISO's GMC allocation in this case.[22]

18. The Commission denies the exceptions on this issue because we agree with the judge that our rejection of Amendment No. 2 did not decide the issues presented here. It is true that the order rejecting the proposal described it in critical terms. However, having made these points, the Commission went on to state:

> 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 the outcome of a hearing to be a viable option. Moreover, we are persuaded by the arguments of the intervenors that the proposed changes contained in Amendment No. 2 are not necessary for ISO operations. Accordingly, we will reject Amendment No. 2.[[23]]

We then distinguished the very issue to be resolved in these proceedings, i.e.:

> 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

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[20]SDG&E Br. at 20-25; SMUD Br. at 12-24; TANC Br. 27-29.

[21]SDG&E Br. at 21.

[22]Id. at 22.

[23]88 FERC at 62,241.

> scope of the proceeding in Docket No. ER98-211-000, et al.[[24]]

19. The Commission believes that two conclusions can fairly be derived from the quoted language. First, although we had reservations about Amendment No. 2, we actually rejected it because there was insufficient time for a thorough evaluation, and, in any event, it was not necessary for ISO operations. Thus, our substantive comments concerning the amendment were dicta. Second, and more significantly, we specifically indicated that the issue of the application of the GMC within the ISO Control Area would be addressed by the Commission in a later proceeding (as it turns out, this one).[25] Thus, however one may read our discussion of Amendment No. 2, it cannot be considered dispositive in these proceedings.

Cost Causation and Benefits Issue

20. The Initial Decision concluded that the ISO's proposal to base CAS charges on CAGL was consistent with cost causation principles. The judge rejected the argument of several CAA customers that applying the CAS charge to behind-the-meter load violates cost causation principles because such load does not use the ISO-Controlled Grid so as to incur CAS costs.

21. In the judge's view, "both 'cost causation' and 'benefits received' are appropriate considerations" in determining whether the CAS charge is just and reasonable.[26] In this regard, she relied on the Commission's decision in Midwest Independent System Operator, Inc. (Opinion No. 453-A),[27] for the idea that "all customers using that grid share in all costs of the grid, because they all benefit."[28]

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[24]Id.

[25]The proceeding referred to, Docket No. ER98-211-000, et al., involved the California ISO's GMC tariff for 1998, which was resolved by settlement. California Independent System Operator Corp., 83 FERC ¶ 61,247 (1998). Thus, decision on the issue was deferred to the instant case.

[26]99 FERC at 65,109.

[27] 98 FERC ¶ 61,141, reh'g denied, 99 FERC ¶ 61,258 (2002), modified on other grounds, 101 FERC ¶ 61,113 (2002).

[28]99 FERC at 65,109, quoting Opinion No. 453-A, 98 FERC at 61,412 (footnote
(continued...)

22. The judge further held that the CAA customers' argument had mischaracterized the nature of the CAS charge, which represented the ISO's administrative costs of providing essential services necessary "[to] ensur[e] the safe, reliable operation of the transmission grid and the dispatch of bulk power supplies" consistent with regional and national reliability standards.[29] As she elaborated:

> As noted by DWR witness, Mr. Werner, all load is wholly dependent on the performance of these Control Area Services, without which no load-serving entity, whether self-served, behind-the-meter, or whatever, could operate. DWR-2 at 14-15. These services cannot be self-provided, nor can these services be duplicated by SC's or any other parties operating in a smaller service territory area within the ISO's Control Area footprint.[[30]]

While all utilities self-provide or purchase control area services for their service territories, the judge observed, "these more limited service territory functions are not the same as those which must be provided by the ISO in its capacity as the Control Area Operator."[31]

23. The Initial Decision rejected the arguments made by the CAA customers that they do not use the ISO's services. She therefore concluded that treating all load the same for purpose of the allocation of the CAS charge is just and reasonable, so that "all load-

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[28](...continued)
omitted) (emphasis the judge's).

[29]Id. at 65,110 (footnote omitted), citing Exh. S-1 at 12; Exh. ISO-29 at 13. In this context, she refers to the Master Definition Supplement of the ISO Tariff, which states that the ISO's Control Area Operator services include performing operation studies, system security analyses, transmission maintenance, system planning for reliability, integration with other control areas, emergency management, outage coordination, transmission planning, and scheduling in the Day-Ahead and Hour-Ahead markets. Id., citing ISO Tariff Sheet No. 308A & Exh. DWR-18.

[30]Id.

[31]Id., citing Exh. ISO-29 at 24:9-12.

serving entities should pay for these administrative CAS costs comparably on the basis of their gross load."[32]

24. A number of parties except to the Initial Decision's resolution of this issue.[33] SMUD, for instance, argues that (1) the judge improperly relied on Opinion No. 453-A, which "stands for the proposition that ISO charges will apply only to gross load of users of the grid," i.e., the loads of ISO members only, while in this case charges are being assessed on non-grid loads delivered by non-grid facilities of non-ISO members;[34] (2) the judge erroneously concluded that the California ISO was solely responsible for Control Area reliability, contrary to the WSCC's Minimum Operating Reliability Criteria (MORC), which permits "sharing of responsibility" for reliability "among entities within the Control Area";[35] (3) the judge ignored that SMUD and other customers have the right and obligation to self-provide control area services, which would be duplicated by CAS; and (4) the judge's benefits received theory violates established cost-causation principles.

25. The Commission affirms the Initial Decision on this issue. At the outset, we find that the Initial Decision reasonably relied on Opinion No. 453-A, which rejected the argument that inclusion of bundled loads in the cost adder employed to calculate the Midwest ISO rates was improper because those loads were served by generation which did not use facilities controlled by the ISO. In denying this objection, the Commission observed:

> 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

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[32]Id. at 65,111, citing Exh. DWR-2 at 16; Exh. S-1 at 7.

[33]See CAC/EPUC Br. at 38-43; Modesto Br. at 13-18; SMUD Br. at 24–27; TANC Br. at 29-30.

[34]SMUD Br. at 29-30 (emphasis in original).

[35]Id. at 30-33.

> 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.[36]

This was consistent, we went on to explain, with established Commission policy that an "integrated transmission grid is a cohesive network moving electricity in bulk"[37] so that "all customers using that grid share in all costs of the grid, because they all benefit."[38] Thus, Opinion No. 453-A concluded that:

> [L]oad 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. Similarly, more efficient operation of the regional grid, including an effective congestion management scheme, should result in the ability of the regional grid to accommodate greater power flows, and thus more transactions than otherwise possible. This should increase the supply of competing generation available to load-serving entities.[39]

In sum, the judge reasonably relied on this language, in which the Commission established that the benefits received by loads served through non-grid facilities justified the allocation of costs to those loads.

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[36]Opinion No. 453-A, 98 FERC at 61,412.

[37]Id., quoting Appalachian Power Company, 63 FERC ¶ 61,151 at 61,978, supplemental order, 64 FERC ¶ 61,327 (1993).

[38]Id., citing Western Massachusetts Electric Company v. FERC, 165 F.3d 922 (D.C. Cir. 1999); Western Massachusetts Electric Company, 63 FERC ¶ 61,222 (1993), reh'g denied, 66 FERC ¶ 61,167 at 61,334-35 (1994).

[39]Id.

26. The Commission also rejects the claim that the judge's approach somehow violates cost causation principles. These principles have authoritatively been described thusly: "Properly designed rates should produce revenues from each class of customers, which match, as closely as practicable, the costs to serve each class of individual customer."[40] While this fundamental idea of matching costs to customers is often referred to in terms of cost causation, it has also often been described in terms of the costs which "should be borne by those who benefit from them."[41] Indeed, in a recent order rejecting arguments that ISO-related costs should not be assigned to PG&E's existing contract customers, the Commission expressly stated:

> Concerning the application of cost causation principles . . . enhanced reliability and market development resulting from industry restructuring are benefits that are distributed across the spectrum of energy participants.[[42]]

Thus, the Initial Decision accurately characterized cost causation and received benefits as alternate means of expressing the same concept.

27. We affirm the factual findings of the Initial Decision that the CAS in question are not and could not be self-provided. The record evidence on this point supports her finding. For example, while SMUD explained that it self-provides various services for its transmission facilities and loads, the ISO demonstrated that those services, provided only in SMUD's individual service area, were not the same services provided by the ISO on a Control Area-wide basis which can only be provided by the Control Area operator.[43]

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[40]Alabama Electric Cooperative, Inc. v. FERC, 684 F.2d 20, 27 (D.C. Cir. 1982) (internal quotation omitted).

[41]Gulf Power Co. v. FERC, 983 F.2d 1095, 1100 (D.C. Cir. 1993).

[42]Pacific Gas and Electric Co., et al., 101 FERC ¶ 61,151 at P 23 & n.39 (2002), citing e.g., Remedying Undue Discrimination through Open Access Transmission Service and Standard Market Design, Notice of Proposed Rulemaking, FERC Stats. & Regs.
¶ 32,563 at P 35 (2002); California Power Exchange, 85 FERC ¶ 61,263 at 62,068 (1998).

[43]See, e.g., Tr. 955-58 (testimony of Mr. Lyon). Mr. Lyon distinguished between the control area-wide services provided by the ISO and services performed by a customer

(continued...)

The excepting parties' reliance on reliability standards suffers from the same flaw. The general prescription of the MORC standards that all utilities bear some responsibility for reliability does not contradict the fact that certain significant tasks to ensure reliability are in the exclusive province of the control area operator. Finally, as the judge noted, all load is wholly dependent on the performance of CAS, without which no load serving entity could operate. These services cannot be self-provided, nor can these services be duplicated by SCs or other parties operating in a smaller service area within the ISO's footprint.

28. However, the Commission believes that the judge cast too wide a net with the gross load approach in one respect. Customers with behind-the-meter generation who primarily rely on that generation to meet their energy needs have made a convincing argument that use of gross load results in this customer class being allocated too great a share of CAS costs. To take into account the more limited impact such customers have on the ISO's grid, the Commission finds that they should be allocated CAS costs on the basis of their highest monthly demand placed on the ISO's grid, rather than on gross load. In this manner, their more limited dependence on the ISO grid will be reflected in their allocation of the CAS costs. Customers eligible for such treatment are those with generators with a 50 percent or greater capacity factor.[44]

4. Retail Behind-the-Meter Load

29. The Initial Decision concluded that the ISO's proposal to allocate the CAS Charge to behind-the-meter load, whether wholesale or retail, is appropriate because such load "cause" CAS cost to be incurred and "benefit" from CAS services even when there not actually using power transmitted over the ISO-controlled grid. The judge further held that there was no relevant distinction to be made in the treatment of retail and wholesale behind-the-meter load. She determined that there was no distinction due to the public or private nature of facilities connecting onsite generation with load. She observed that measurable energy will flow to or from the ISO-controlled grid regardless of whether the generator output behind-the-meter is wholesale or retail in nature. Finally, the judge determined that equal treatment of wholesale and retail load is consistent with the

[43](...continued)
within a "particular service territory." Id. at 956. While SMUD maintains (SMUD Br. at 36) that Mr. Lyon conceded that SMUD self-provides the same services, a review of the relevant testimony reveals that the witness never abandoned this crucial distinction.

[44]Capacity factor is the ratio of the average load or output of a generator for a given time period to the capacity rating of the generator.

physical laws governing electricity and underscores the fairness of a system-wide allocation of the CAS charge for all loads interconnected with the ISO-controlled grid.

30. The Initial Decision rejected arguments that the Public Utilities Regulatory Policy Act (PURPA) precludes the ISO from assessing the CAS charge based on Control Area Gross Load. In the judge's view, granting retail behind-the-meter load an exemption from the CAS charge would provide an unfair advantage over other market participants that will not be similarly exempted from the CAS charge.[45] This was consistent with PURPA, she determined, which was not enacted to give Qualifying Facilities (QFs) an unfair advantage over other market participants.[46]

31. The Initial Decision also found that the ISO's proposal to estimate a retail customer's load served by generation located behind-the-meter is reasonable. According to the judge,

> having determined that it is just and reasonable for all loads interconnected to the grid to pay its share of the costs incurred by the ISO in performing basic Control Area Services, . . . it is reasonable to conclude that parties with behind-the-meter loads that elect not to permit the ISO to perform metering 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 allocation and billing of CAS charges.[[47]]

32. On exceptions, CAC/EPUC contends that by treating wholesale and retail behind-the-meter load in the same manner, the judge ignored the unique protections provided to retail behind-the-meter load under PURPA. They contend the Initial Decision thus violates PURPA as it fails to encourage the development of cogeneration. They further argue that the judge's decision ignores the PURPA requirements of the net treatment of QFs, as well as its mandate for back-up and maintenance power to QFs at reasonable rates and prohibits the assumption of simultaneous outages at system peak.

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[45] 99 FERC at 65,124.

[46] Id., citing Southern California Edison Co., 70 FERC ¶ 61,215 at 61,675 & n.14 (1995).

[47] 99 FERC at 65,129-30.

33. CAC/EPUC goes on to argue that the judge violated well established cost causation principles by finding the ISO CAGL proposal reasonable. CAC/EPUC claims that the Initial Decision would improperly shift costs away from those customers that cause the ISO to incur its CAS costs to customers with generation located behind-the-meter, which do not cause the ISO to incur those costs.

34. The Commission denies these exceptions. Once again, we agree with the judge's decision that it is reasonable to allocate the CAS charge to all load that benefits from the service provided by the ISO. As we have discussed above, however, behind-the-meter customers, wholesale or retail, with a generator that has a capacity factor of 50 percent or more, are to be allocated CAS costs based on their highest monthly demand. This exception applies to whether the behind-the-meter generation is wholesale or retail.

35. Finally, we also agree, for the reasons stated by the judge, that the ISO's proposal does not violate the terms of PURPA or its implementing regulations.

5. Assessment of GMC on "Other Appropriate Parties"

36. As the Initial Decision explained, the ISO proposed to assess both CAS and MO charges to "other appropriate parties."[48] While the term is not defined by the ISO's tariff, the ISO has described such entities as Governmental Entities (GEs), generally municipal utilities and government agencies serving behind-the-meter load "for whom all or a portion of their volumes of Demand are not scheduled, metered, or settled with the ISO by an SC."[49] Thus, according to the ISO, while the "other appropriate party" designation allows GEs as well as other non-SC power users to avoid the costs and expenses associated with becoming a SC, they would agree to be billed directly by the ISO for their share of the CAS and MO charges.

37. As a general principle, the Initial Decision upheld the principle that "just and reasonable billing procedures require that bills be directed to the [CAGL] of each Load Serving Entity who has contributed to the incurrence of CAS costs and benefitted from CAS functions."[50] The judge rejected the argument that lack of "privity of contract" between the GEs and the ISO should absolve the former of their responsibility for the CAS and MO costs. She also determined that permitting the ISO to directly bill entities

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[48]99 FERC at 65,139.

[49]Id. at 65,141 & n.141, quoting Exh. ISO-27 at 5-7.

[50]Id. at 65,141.

responsible for these costs would lower administrative fees and expenses by eliminating the SC's role as a middleman. However, she was unwilling to approve the ISO's proposal because, under that proposal, if the "other appropriate parties" refused to pay the bills, the amounts would instead be passed through to SCs. Thus, the judge explained:

> SCs will be adversely impacted by this policy. Billing of the CAS charge should not be a matter of convenience for the ISO anymore than responsibility for payments should be considered "voluntary."[51]

The judge therefore ordered the ISO to make a compliance filing "to specifically define" the term "other appropriate parties" and to provide legal and factual support for imposing its GMC on these parties.[52]

38. On exceptions SMUD complains that the term is dangerously vague and that it attempts to impose grid costs on entities outside the ISO's footprint and that the provision should be stricken from the ISO's tariff.[53] At the same time, SMUD recognizes that the Initial Decision does not constitute a final ruling on the ISO's proposal to bill GMC charges to other appropriate parties. Nonetheless, SMUD opposes charging the GMC to GEs because the ISO should not be permitted to impose costs on parties with whom it does not have any contractual relationship.[54]

39. The Commission denies the exceptions on this issue. First, we have already rejected the argument that entities using the services of the ISO do not benefit and should avoid payment for such service. Second, we agree with the judge that much of the confusion surrounding this issue will be remedied once the ISO clarifies who exactly it intends to cover with its "other appropriate parties" provision. We also affirm the judge's finding that payment by these entities cannot be on a voluntary basis. Therefore, we will require the ISO to make a compliance filing defining the term, clarifying to whom it applies, its factual and legal justification, as well as eliminating its objectionable voluntary nature.

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[51] Id.

[52] No party excepted to the Initial Decision's finding that no "other appropriate parties" would be charged for the IZS component of the GMC. Id. at 65,140.

[53] SMUD Br. at 54. TANC makes a similar argument.

[54] Id. at 58.

C. PG&E Passthrough Issues (ER01-424-000, et al.)

40. The second part of these proceedings involves the PG&E PTT. As the judge described it, PG&E intends by this tariff to recover from its CAA customers, on a dollar-for-dollar basis, any GMC that it is being or has been charged by the California ISO after January 1, 2001.[55] The tariff does not include any reimbursement to PG&E for the costs it incurs internally in performing these services.

1. Whether PG&E's GMC Passthrough Is a New Service

41. As the framework for this issue, the judge employed what she termed the Commission's "new service" precedent.[56] Under this precedent, the relevant question is whether a utility has already "obligated itself to provide a particular service under an existing contract" (as opposed to providing a new service); the Commission "will not infer an obligation to provide a service that is not explicitly required."[57]

42. The judge rejected the CAA customers' position that this result conflicted with Commission precedent. In this regard, the judge specifically relied on Florida Power & Light Company (FP&L),[58] where the Commission held that a utility had properly filed a new tariff so that it would be compensated for back-up service in connection with firm capacity and energy agreements with an existing customer which did not already provide for such a service. She distinguished Southwestern Electric Power Company (Southwestern),[59] relied on by the CAA customers, as establishing a broad view by the Commission of how it would determine what constitutes a change in rates in order to exercise its suspension and refund authority under Section 205.

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[55] 99 FERC at 65,158.

[56] Id. at 65,164.

[57] Id., (footnote omitted), quoting Wisconsin Electric Power & Light Co., 46 FERC ¶ 61,019 at 61,111 & n.7 (Opinion 321), reh'g denied, 48 FERC ¶ 61,247 (1989), aff'd, Wisconsin Public Power, Inc. v. FERC, 918 F.2d 225 (D.C. Cir. 1990).

[58] 62 FERC ¶ 61,251, reh'g denied, 65 FERC ¶ 61,411 (1993).

[59] 39 FERC ¶ 61,099 (1987).

43. On exceptions, several of the CAA customers, as well as Trial Staff, take issue with the manner in which the judge framed the new service issue.[60] For example, SMUD contends that the FPA recognizes only initial rates or rate changes, and that the Initial Decision erred in categorizing the PTT as a new service.[61] In SMUD's view,

> since it is indisputable that PG&E's CAA customers are not new, the PTT filing of PG&E can only be considered a rate change, ostensibly offered to modify, alter or otherwise amend the rates under PG&E's agreements with its CAA customers, including SMUD's own IA with PG&E.[62]

SMUD, NCPA and Staff further maintain that the precedent relied on by the Initial Decision (Southwestern, FP&L and Opinion No. 321), actually supports their position that a new service for existing customers requires a rate change, which in turn requires the customers' tariffs on file to countenance such a change. Thus, the parties argue that the Initial Decision abrogates existing contracts, contrary to Commission policy, or at the least evades the Mobile-Sierra doctrine by authorizing modifications of the existing CAAs, without reference to whether such modifications are permitted by the terms of the CAAs.[63]

44. The Commission affirms the Initial Decision on this issue. At the outset, the judge properly avoided being drawn into a discussion of initial rates. The Commission has long held that, for purposes of Section 205, "where the service is new, but the customer is not, such filings will be deemed changes in rates[.]"[64] As the judge recognized, in the context of whether or not a rate filing can be suspended and refunds thus ordered, we define rate changes comprehensively in order to fulfill our statutory obligation to protect consumers from excessive rates.[65] But our determination that

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[60]NCPA Br. at 8-9; SMUD Br. at 60-62; Staff Br. at 6-11.

[61]SMUD Br. at 61.

[62]Id. (emphasis in original; footnotes omitted).

[63]Id. at 16-22.

[64]Southwestern Electric Power Co., 39 FERC ¶ 61,099 at 61,293 (1987).

[65]As we explained in Southwestern, under Section 205(e) of the FPA, the Commission may only exercise its suspension and refund authority in assessing a

(continued...)

PG&E's PTT represents a rate change, subject to the suspension and refund provisions of FPA Section 205, is not dispositive of whether a new and different service is at issue for which a new tariff is appropriate. The excepting parties fail to recognize this distinction. However, as the Initial Decision discerned, we have previously taken this specific approach.[66] Finally, none of the precedent on which they rely is to the contrary; rather, those cases uniformly deal with the issue of whether a filing is an initial rate or a rate change.

45. The Commission rejects the claim of some of the CAA customers that the result here runs afoul of the Commission's longstanding policy not to abrogate existing contracts in the context of industry restructuring. The policy does not mean, as the CAA customers here would have it, that existing contract holders are immune from all change brought about by restructuring.[67] Nor should it result in a public utility being responsible for trapped Commission-approved charges, rather than allowing the charges to be passed through to the appropriate customers.

46. We also deny that the judge's approach evades the Mobile-Sierra doctrine in any manner. Under Mobile-Sierra, a utility cannot unilaterally "file a new rate under Section 205 to supersede the agreed-upon rate."[68] However, the existing CAAs are not being modified in any manner, so that the agreed-upon rate for PG&E's CAA services is not being superseded. Rather, as explained in more detail below, these customers of PG&E are receiving a new and different service in addition to the service they already receive under the CAAs, and the rate at issue here is the passthrough of the costs to PG&E billed by the ISO for these services.[69]

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[65](...continued)
"change in rate." Id.

[66]E.g., Opinion No. 321, supra; Southern California Edison Company, 50 FERC ¶ 61,138 at 61,409-12 (1990).

[67]As we stated in Opinion No. 458-A, enhanced reliability and market development resulting from industry restructuring are benefits that are distributed across the spectrum of industry participants. 101 FERC at 61,151.

[68]Boston Edison Co. v. FERC, 233 F.3d 60, 65 (1st Cir. 2000) (emphasis added).

[69]We note that in another proceeding, PG&E is seeking additional passthrough to CAA customers of ISO-related costs it incurs. See Pacific Gas and Electric Co., Docket No. ER00-565-000. Obviously, none of the costs recovered by PG&E in the instant
(continued...)

2. New Service and Cost Causation Concerning CAS

47. The Initial Decision held that as to the CAS portion of the proposed tariff, PG&E "seeks recovery of costs for a service that is fundamentally different from that provided under the CAAs."[70] As the judge went on to explain:

> The CAS charge represents the ISO's administrative costs, as Control Area Operator, of providing basic services essential to ensure the safe, reliable operation of the transmission grid and the dispatch of bulk power supplies in accordance with regional and national reliability standards. These services cannot be self-provided, nor duplicated by PG&E or any other SC in the smaller service territory area within the ISO's Control Area footprint. Further, these services did not even exist until the ISO became operational in January of 1998.[[71]]

In support of this conclusion, the judge substantially relied on the testimony of PG&E witness Mr. Bray that the CAS functions performed by the ISO are different from and in addition to the services already provided by PG&E under the CAAs.

48. The judge rejected the opposing theory of the CAA customers that they do not receive any services or benefits above those which PG&E used to provide in the old, pre-ISO world. She reiterated her findings from the first phase of the proceedings that the ISO is providing basic services essential to ensure the safe and reliable operation of the transmission grid and the dispatch of bulk power supplies, and that these services cannot

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[69](...continued)
proceedings should be duplicated elsewhere.

[70]Id. The judge differentiated the MO component of GMC, which she found did not represent a new service and thus could not be passed through by PG&E to the CAA customers by means of the PTT. 99 FERC at 65,169-70. As noted above, the Commission is summarily affirming this finding.

[71]Id. (footnote omitted).

be duplicated or self-provided by any party operating in a smaller area within the ISO's Control Area footprint.[72] It followed, in her view, that the CAAs are receiving new benefits, and that the passthrough of PG&E's costs in providing these benefits are appropriately collected pursuant to a new tariff.

49. The CAA customers and Staff take exception to the Initial Decision's holding that the customers are receiving a new service.[73] NCPA is fairly typical, arguing strenuously that the record establishes otherwise:

> NCPA established that the service currently provided to the CAA customers is not in any way distinguishable from service prior to the commencement of ISO operations. (Exh. No. NCP-1 at 9:26 -27 (Dockham).) Rather, the "new" functions described by PG&E are simply a repackaging of its preexisting performance obligations under the IA and do not confer additional benefits on NCPA. As NCPA witness Dockham testified, "the IA contemplated all of the services that were necessary for the provision of Firm Transmission Service . . . ." (Exh. No. NCP-1 at 14:5-7. See also id. at 15:5-7.). The "new" services purportedly provided by PG&E under the [PTT] area already encompassed within the four corners of Rate Schedule 142 [i.e., the IA between NCPA and PG&E already on file].[74]

Additionally, several of the excepting parties maintain that the PTT results in double recovery for PG&E of costs already accounted for in the CAAs.[75]

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[72]In support of these findings, the judge cited Exh. S-1 at 12; Exh. ISO-29 at 13, 24:9-12. In this context, she also once again relied on the Commission's decision in Opinion No. 453-A. See 99 FERC at 65,166 & nn. 201 & 202.

[73]BART Br. at 18-26; NCPA Br. at 8-12; SMUD Br. at 66-71; SVPA Br. at 15-29; WAPA Br. at 7-25; Staff Br. 14-16.

[74]NCPA Br. at 9. NCPA further asserts that PG&E conceded in response to several data requests that the PTT does not provide new benefits to the CAA customers. Id. at 10-11, citing Exh. Nos. WPA-6 and WPA-7.

[75]E.g., BART Br. at 26-28; SVP Br. at 30-35.

50. The Commission denies these exceptions. The Initial Decision reasonably rejected the arguments that PG&E is performing no new function as contrary to her findings that the CAA customers are receiving new benefits as a result of the ISO's CAS services. We have affirmed these findings above and need not discuss them again. Furthermore, we find that there was evidence supporting the judge's finding that the services rendered by the ISO are separate and distinct from the services PG&E renders pursuant to the CAAs. For example, PG&E witness Mr. Bray explained in some detail that "[e]very activity that PG&E performs on behalf of each and every CAA Customer as its ISO-certified SC is a new and unique function that it did not provide to the CAA Customers prior to the ISO."[76] Additionally, we find that the contrary testimony offered by NCPA and the other opposing parties fails to come to grips with the fundamentally new and different roles that now exist under the California ISO regime, which entails duties and obligations separate and apart from those PG&E continues to have pursuant to the terms of the CAAs.

51. Thus, while the CAA customers maintain that the GMC PTT offers no new or different service "above and beyond" what they were provided by PG&E in its former guise as a vertically-integrated utility, we agree with the judge that there are indeed distinct services that are performed by the ISO in its role as control area operator for which it is billing PG&E. These include performing operational studies, system security analyses, transmission maintenance standards, system planning to ensure overall reliability. Of course, PG&E formerly provided to the CAA customers all the necessary services required for the safe and reliable operation of a high voltage electric transmission system.[77] Accordingly, the rate schedules for each of the CAAs defined the extent of PG&E's duties and responsibilities for each customer. PG&E's scheduling and scheduling-like activities derived from the fact that PG&E was both a transmission service provider and the control area operator.

52. Now, however, the ISO is the control area operator for the former control area of PG&E (as well as the former control areas of other utilities) and has the responsibility to provide the CAA customers access to the ISO controlled-grid.[78] Consistent with its obligations as a control area operator, the ISO operates a real time Imbalance Energy

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[76]Exh. PGE-32 at 13. See id. at 9-15. Our review of the excepting parties' allegations that Mr. Bray conceded otherwise reveals that they are based on semantic distinctions, rather than substance.

[77]See, e.g., Exh. PG&E-32 at 11.

[78]See, id. at 12.

market to ensure that all generation and all load within the control area are balanced on a moment-to-moment basis, taking into account interchange with other control areas. Specifically, the ISO is responsible for arranging operating reserves, scheduling interchange and maintaining power flows within established operating limits, and providing adequate contribution to interconnection frequency regulation, while PG&E's role is now to coordinate with the ISO on load scheduling and real-time operations, so that the CAA customers gain access to the grid necessary to satisfy the requirements under their contracts.

53. Finally, the allegations of double recovery by PG&E were reasonably rejected by the judge. PG&E submitted comprehensive evidence that "no ISO costs billed to PG&E for ISO Grid Management Charges are included in PG&E's transmission operation and maintenance expense accounts or the [CAAs]."[79]

3. The MO Component

54. The Market Operations (MO) portion of the ISO's GMC represents the ISO's costs of market and settlement related services (the cost of operating and ancillary service market as well as the cost of billing). The billing determinants for this service are equal to a given SC's total purchases and sales of ancillary services.

55. The judge determined that, unlike the CAS, the services provided under the MO component were not new or different services.[80] She found that PG&E failed to explain why its CAA customers should be assessed such charges, which are based on costs incurred by the ISO to arrange for provision of ancillary services defined in the ISO Tariff, as those services are self-provided rather than procured through the ISO markets. Thus, the judge concluded that PG&E's methodology for the recovery of the MO costs from its CAA customers had to be determined according to the terms of the individual CAAs.

56. PG&E asserts that the judge erred in not treating the CAS and MO charges in the same manner. It argues that the record demonstrates that the ISO's MO services are new services and related to service requirements under the ISO Tariff distinct from the CAA

[79] Exh. PGE-6 Revised at 2 (testimony of Mr. King).

[80] 99 FERC at 65,180.

requirements.[81] In this regard, PG&E relies on the testimony of its witness Mr. Bray that there are now competitive markets established for ancillary services and imbalance energy, as opposed to the pre-ISO era when PG&E had no such markets and managed ancillary services as a vertically integrated utility.[82]

57. The Commission agrees with PG&E's exception and reverses the Initial Decision on this issue. According to the record in this proceeding, the MO bucket consists of five elements of ancillary services and two elements of Real-Time Energy.[83] This supports the conclusion that the MO components of PG&E's PTT, like the CAS components, constitute a new and different service to the CAA customers. As with the CAS services, we find that there is no duplication of function of activity between PG&E and the ISO, because the scheduling activities that PG&E performs under the CAAs is unrelated to the ISO activities that give rise to the MO component of the GMC.

58. Many CAA customers argue that they should not be assessed the MO component of the GMC because they can self-provide certain ancillary services. The ISO specifies that only ISO-certified SCs may schedule transactions using the ISO-controlled grid. To generate power, transmit power and/or service load using the ISO grid, each CAA customer needs an ISO-certified SC. In order to self-provide ancillary services, a CAA customer would presumably gain access to the ISO-controlled grid through its own SC. Thus, to the extent a CAA either self-provides ancillary services as its own SC or through PG&E as SC, the ISO is in both situations assessing charges to the responsible SC for accessing the ISO-controlled grid to support transmission service (i.e., MO service).

The Commission orders:

(A) The Commission hereby reverses the Initial Decision on the issues of allocation of CAS charges for customers who primarily rely on behind-the meter load,

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[81] PG&E Br. at 6.

[82] Several CAA customers also argue that there is no discernable difference in the way in which PG&E has sought to passthrough the CAS charge and the MO charge, but draw the opposite conclusion: the judge should not have allowed passthrough of either charge.

[83] The five ancillary services are: (1) Regulation Up; (2) Regulation Down; (3) Spinning Reserves; (4) Non-Spinning Reserves; and (5) Replacement Reserves. The two real-time Energy elements are Instructed Deviations and Uninstructed Deviations.

and of the passthrough of the MO component of the CAS charge, as discussed in the body of this order.

(B) The Commission hereby affirms and adopts the Initial Decision in all other respects.

(C) The ISO is hereby ordered to make a compliance filing concerning its "other appropriate parties" proposal, as discussed in the body of this order, within thirty (30) days of the date of the issuance of this order, unless there is a timely request for rehearing in these dockets. In that event, the compliance filing must be submitted within thirty (30) days of the Commission's final disposition of any such rehearing request.

(D) The ISO is hereby ordered to make refunds and then to file with the Commission a refund report, within thirty (30) and sixty (60) days, respectively, of the date of the issuance of this order, unless there is a timely request for rehearing in these dockets. In that event, the refunds and refund report must be submitted within thirty (30) and sixty (60) days, respectively, of the Commission's final disposition of any such rehearing request.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.