UNITED STATES OF AMERICA 106 FERC 61,032
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

California Independent System Operator Corporation — Docket No. ER01-313-003

Pacific Gas and Electric Company — Docket No. ER01-424-003

San Diego Gas & Electric Company v. California Independent System Operator Corporation — Docket No. EL03-131-000

OPINION NO. 463-A

ORDER ON REHEARING AND CLARIFICATION AND DISMISSING COMPLAINT

(Issued January 23, 2004)

1. In Opinion No. 463,[1] the Commission reviewed an Initial Decision[2] that involved the California Independent System Operator Corporation's (ISO) unbundled grid management charge (GMC), as well as Pacific Gas and Electric Company's (PG&E) filing to pass through the GMC to its customers in a new tariff. In this order, we review a number of requests for rehearing and/or clarification of Opinion No. 463. As discussed below, we essentially deny the requests for rehearing, other than those concerning the Control Area Gross Load (CAGL) issue. Additionally, on June 2, 2000, San Diego Gas & Electric Company (SDG&E) filed a complaint against the ISO related to one of the issues addressed in Opinion No. 463. In this order, we also address and dismiss SDG&E's complaint. Our decisions in these dockets benefits customers by affirming the reasonable allocation of the ISO's costs among its customers, and ensuring that the affected public utilities can recover their reasonable costs.

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[1] California Independent System Operator Corp., et al., 103 FERC ¶ 61,114 (2003).

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

Background

2. On November 1, 2000, (as amended on December 15, 2000) the ISO submitted its proposed unbundled GMC to the Commission. On November 13, 2000, PG&E submitted its proposed GMC Pass-Through Tariff (PTT), intended to permit PG&E to pass the GMC to certain of its wholesale existing contract customers. In view of the complexity of some of the arguments made on rehearing, we believe that a restatement of the first principles of these two filings would be helpful.

3. The ISO was created by the State of California to ensure efficient use and reliable operation of the state electric transmission grid. For the ISO, the GMC is the sole source of its revenue requirement, designed to collect the costs of operating the ISO, including meeting its start-up and development costs, its ongoing capital expenditure costs, and its operation and maintenance costs.[3] In its filing here, the ISO proposed to unbundle the GMC into three service categories,[4] two of which are at issue in this order: the Control Area Services (CAS) category, and the Market Operations (MO) category.[5] The Initial Decision described the CAS, by far the largest and most controversial of the three categories, as including

> the ISO's costs, as the control area operator, associated with ensuring reliable, safe operation of the transmission grid and the entire control area (e.g., the cost of scheduling generation, imports, exports and wheeling transactions the day before and the hour before actual operations). The billing determinants for this service are based on control area gross load and exports, with [CAGL] defined as all demand for energy within the ISO control area, except for auxiliary load (i.e., energy used in the power production process) or load that is electrically isolated from the ISO

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[3] The ISO also has on file a Transmission Access Charge (TAC), which is a charge paid for the use of the ISO-controlled grid collected to allow Participating Transmission Owners to recover their own transmission revenue requirements, for facilities and entitlements owned by them but operated by the ISO. See California Independent System Operator Corp., 100 FERC ¶ 61,209 (2002).

[4] The ISO's original GMC, filed with the Commission in 1997, was bundled. All disputes relating to the original GMC were resolved by a settlement. See California Independent System Operator Corp., 83 FERC ¶ 61,247 (1998).

[5] The third proposed service category, Inter-Zonal Scheduling (IZS), includes the ISO's costs of administering congestion management and various aspects of firm transmission rights.

> controlled grid (i.e., load that is not synchronized with the ISO controlled grid).[[6]]

The proposed MO category, also in dispute, was intended to include the ISO's costs of market and settlement-related services.

4. PG&E's proposed PTT was designed to recover costs from certain of its existing customers with wholesale transmission contracts, also known as Control Area Agreement (CAA) customers. As described by the judge, the PTT was designed to recover from these customers

> only the ISO's operating and administrative costs of service provided by the ISO and only the costs approved for recovery by the Commission in these consolidated dockets. PG&E asks that it be authorized to pass-through to its CAA customers, on a dollar-for-dollar basis, any GMC that it is or has been charged by the ISO after January 1, 2001, under terms approved by the Commission . . . . PG&E affirms that it is not asking for any reimbursement for the costs it incurs internally in performing these services, but simply seeks to be able to pass-through the GMC it receives from the ISO.[[7]]

5. In Opinion No. 463, the Commission affirmed the Initial Decision in most respects, but reversed certain of the presiding judge's findings. With respect to the ISO tariff, we generally upheld the judge's determination that the CAS charge should be based on CAGL. In this context, the Commission concluded that (1) the ISO's proposal to base CAS charges on CAGL was consistent with cost causation principles, because all load was dependent and received benefit from the performance of CAS services by the ISO; (2) only the ISO could provide these CAS services; they could neither be self-provided by CAA customers nor duplicated by any other entity operating in a smaller service territory within the ISO's control area; (3) the judge had reasonably relied on Opinion No. 453-A[8] for the proposition that "the benefits received by loads served through non-grid facilities

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[6] 99 FERC at 65,083, citing Exh. ISO-1 at 24. A billing determinant is the measure of demand used to determine charges under a rate schedule or agreement. It does not necessarily coincide with a customer's actual demand as measured in a billing period.

[7] 99 FERC at 65,158, citing Ex. PGE-2 at 3-4.

[8] 98 FERC ¶ 61,141, reh'g denied, 99 FERC ¶ 61,258, modified on other grounds, 101 FERC ¶ 61,113 (2002), on remand, 102 FERC ¶ 61,193 (Remand Order), reh'g denied, 104 FERC ¶ 61,012 (2003) (Midwest ISO).

justified the allocation of costs to those loads."[9] We did find, however, that an exception should be made for customers with behind-the-meter generation who primarily rely on that generation to meet their energy needs:

> 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 based 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.[[10]]

We made clear that this exception also applied equally to retail behind-the-meter customers. Otherwise, Opinion No. 463 affirmed the judge's finding that retail behind-the-meter load was appropriately allocated the CAS charge, and that such allocation did not violate the Public Utility Regulatory Policies Act of 1978.

6. Opinion No. 463 also affirmed the judge's decision that PG&E's new tariff was appropriate, as it was designed to pass through costs representing "distinct services that are performed by the ISO in its role as control area operator, for which it is billing PG&E."[11] Therefore, the Commission agreed with the judge that the PTT in no way superseded or modified the existing agreements. However, we did reverse the Initial Decision's determination that, because the MO portion of the GMC represented services that PG&E was already performing under the CAAs, it could not be passed through in the PTT. Rather, we concluded:

> [T]he 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 [sic] unrelated to the ISO activities that give rise to the MO component of the GMC.[[12]]

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[9] Opinion No. 463, 103 FERC ¶ 61,114 at P 25.

[10] Id. at P 28 (footnote omitted).

[11] Id. at P 51.

[12] Id. at P 57.

7. Timely requests for rehearing and/or clarification of Opinion No. 463 were filed by the ISO, San Diego Gas and Electric Company (SDG&E), Southern California Edison Company (SoCal Edison), Sacramento Municipal Utility District (SMUD), Silicon Valley Power (SVP), the Cogeneration Association of California and the Energy Producers and Users Coalition (CAC/EPUC), Modesto Irrigation District (MID), Turlock Irrigation District (Turlock), Northern California Power Agency (NCPA), Transmission Agency of Northern California (TANC), the Western Area Power Administration (Western), and the Public Utilities Commission of the State of California and the California Electricity Oversight Board (collectively, California PUC).[13]

8. In this order, we address four issues raised on rehearing and/or clarification by the parties: (1) Opinion No. 463's decision to use CAGL for allocation of CAS costs, and the exception established by the Commission to the use of CAGL; (2) Opinion No. 463's conclusion that PG&E's proposed tariff is for recovery of costs associated with a new service; (3) the dispute between SDG&E and the ISO concerning the GMC as applied to portions of the Southwest Powerlink (this is also the subject of SDG&E's complaint); and (4) the ISO's contention that the Initial Decision erred in requiring it to directly bill the CAS charge to Qualifying Facilities and certain Governmental Entities. All other arguments raised by the parties in their requests for rehearing and/or clarification have been fully considered by the Commission and are denied.

Preliminary Matters

9. We note that on April 6, 2001, PG&E filed for Chapter 11 bankruptcy protection. Although the Bankruptcy Code provides that the filing of a bankruptcy petition automatically stays certain actions against the debtor,[14] the Code also provides an exception from this automatic stay for:

> An action or proceeding by a governmental unit . . . to enforce such governmental unit's or organization's police and regulatory power, including the enforcement of a judgment other than a money judgment, obtained in an action or proceeding by the governmental

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[13] The ISO, MID, SoCal Edison and SMUD filed pleadings that were all essentially answers to various requests for rehearing. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2003), prohibits an answer to a rehearing request unless otherwise ordered by decisional authority. We are not persuaded to accept the instant answers and will, therefore, reject them. Additionally, SDG&E filed an answer to the ISO's answer, which we will also reject.

[14] 11 U.S.C. § 362(a)(1) (1994 & Supp. 2000).

> unit to enforce such governmental unit's or organization's police or regulatory power.[15]

The Commission has found in the past that actions taken under the authority granted it by the Federal Power Act and the controlling regulations fit within this exception, and, therefore, are exempt from the automatic stay provision.[16] Here, we are exercising our regulatory power under Section 205 of the Federal Power Act.

Discussion

A. The Use of Control Area Gross Load for Allocation of CAS Costs

1. Opinion No. 463 and the Requests for Rehearing

10. The judge concluded that the ISO's proposal to allocate CAS charges on CAGL was consistent with cost causation principles. The Commission concurred and found that the use of CAGL for the allocation of CAS costs was generally acceptable. The Commission stated that while the fundamental idea of matching costs with customers is often referred to in terms of cost causation, it has also been described in terms of the costs which "should be borne by those who benefit from them." The Commission concluded that the Initial Decision accurately characterized cost causation and received benefits as alternate means of expressing the same concept. However, while the Commission affirmed the judge, it did require an exception: for those customers with behind the meter generation who primarily rely on that generation to meet their energy needs and who have generators with a 50 percent or greater capacity factor, the allocation of CAS costs would be done on the basis of their highest monthly demand on the ISO grid rather than on CAGL.

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[15] 11 U.S.C. § 362(b)(4) (1994 & Supp. 2000).

[16] See Virginia Electric and Power Co., 84 FERC ¶ 61,254 (1998) and Century Power Corp., 56 FERC ¶ 61,087 (1991). The Commission's conclusion on this matter is consistent with judicial precedent regarding the scope of the exemption to the automatic stay. E.g., Board of Governors of the Fed. Reserve Sys. v. MCorp Fin., Inc., 502 U.S. 32 (1991); SEC v. Brennan, 250 F.3d 65 (2nd Cir. 2000); NLRB v. Continental Hagen Corp., 932 F.2d 828 (9th Cir. 1991); United States v. Commonwealth Cos. Inc., 913 F.2d 518 (8th Cir. 1990); NLRB v. Edward Cooper Painting, Inc., 804 F.2d 934 (6th Cir. 1986); Penn Terra Ltd. v. Dept. of Environmental Resources, 733 F.2d 267 (3rd Cir. 1984); see generally 3 Collier on Bankruptcy § 362.05 (15th ed. rev. 2000).

11. A number of parties have filed requests for clarification and/or rehearing on this issue. SoCal Edison states that the exception to the use of CAGL on a demand-related basis is unreasonable for certain customers, cannot be implemented retroactively, and is not practical to implement in the future without certain modifications. Accordingly, SoCal Edison requests that the energy-based CAGL allocation method be retained for the period January 1, 2001 through December 31, 2003. However, SoCal Edison requests that the CAS charge prospectively be assessed on a demand-related basis, i.e, the highest demand each month that customers place on the ISO-controlled grid. SoCal Edison also requests clarification that the exception includes entities such as itself who have numerous behind the meter generators located on their distribution systems and are thus behind the meter wholesale meter generators.

12. MID requests rehearing and/or clarification on the exception. Specifically, MID states that while it concurs in the Commission's conclusion that the use of CAGL casts too wide a net and allocates to entities with behind the meter generation more than their fair share of CAS costs, the 50% capacity factor does not satisfy the Commission's intent. MID believes that the capacity factor of a generating unit is not sufficient to determine if a customer primarily depends on behind the meter generation to satisfy its energy needs because a customer with a small generating unit that satisfies this eligibility criteria would then allow the customers' entire load to be eligible for the exception and this was obviously not the outcome the Commission intended. MID believes that to properly determine eligibility, it is necessary to compare the quantities of energy supplied from behind the meter generation to the quantities of energy supplied from the ISO-controlled grid and that to be eligible for the exception a customer must serve no more than 50% of its behind the meter load from the ISO-controlled Grid. MID also requests that the Commission clarify that its ruling affirming the ALJ decision to permit the ISO to assess CAS charges on the basis of CAGL is not precedential to future GMC rate design efforts. In support, MID notes that the Commission stated that the GMC was a work in progress and that the GMC was susceptible to further refinement.

13. The California PUC also filed a request for rehearing and/or clarification relating to the issue of CAGL. The California PUC states that while it is pleased with the Commission endorsing the concept of an allocation of CAS costs based on demand, the Commission was arbitrary and capricious in the use of a 50% capacity factor to determine the eligibility requirement in that the use of a demand-based allocation charge and a 50% capacity factor have no record foundation. The California PUC also requests clarification as to how the capacity factor for multiple generators would be determined, over what time period, and what was precisely meant by "highest monthly demand." The California PUC also argues that the use of a capacity factor does not necessarily bear any relation to the customer's dependence on the ISO-controlled grid.

14. SMUD also requests rehearing and/or clarification on the use of CAGL to allocate CAS costs. Specifically, SMUD requests that the Commission clarify that: (1) "other

appropriate parties" must not include load that is not served from the ISO controlled grid or for which load-serving entities self-provide the GMC services, and (2) the term "behind the meter" generation, as used in Paragraph 28 of Opinion No. 463, refers to both owned resources and generation delivered behind the meter (generation that does not flow across the meter out of the ISO-controlled grid). In support of the first point, SMUD argues that the amount and type of CAS that SMUD self-supplies for reliable grid operation was and continues to be 100% sufficient to serve the load within the SMUD control area and not place any burden on the ISO's Control Area Operator. SMUD also argues that the "benefits received" criteria employed by Opinion No. 463 do not provide any meaningful test under cost causation principles because it completely ignores and thereby eliminates the ability to self-provide control area services. Furthermore, SMUD argues that the assignment of CAS costs undermines the contractual bargain in its existing transmission contract (ETC) which bars the ISO from assigning any CAS costs to SMUD so long as the underlying contracts remain in existence.

15. Turlock requests that the Commission eliminate the 50% capacity factor test and replace it with a requirement that a utility pay the CAS costs on the basis of the utility's use of the ISO controlled grid during the ISO's monthly peak. Turlock believes that this approach will serve the Commission's goal of reflecting the fact that utilities with behind the meter generation place more limited dependence on the ISO-controlled grid which in turn should be reflected in their allocation of CAS costs. Turlock notes that the 50% capacity factor was not sponsored or supported by any party and is not in the record in this proceeding. Turlock also requests clarification of how the 50% capacity factor eligibility requirement would be implemented, i.e., whether a utility with one generator with a 50% capacity factor qualifies for such treatment when it also has a number of peaking facilities that would, by definition, not meet this standard. Turlock also notes that there are also a number of intermediate units that during periods of drought would be unlikely to meet the 50% capacity factor and therefore requests that the eligibility requirement be done on a monthly basis so that if any one generator of a utility meets the 50% standard in a month, then CAGL billing for CAS would not apply to that utility for that month. Turlock also requests clarification regarding the time periods to be utilized for the calculation of the billing demands and the capacity factors, i.e., over a month or calendar year.

16. CAC/EPUC jointly filed a request for clarification or, in the alternative, rehearing of Opinion No. 463 on this issue. CAC/EPUC state that while the Opinion appears to embody principles that would be supportive of Customer Generation, interpretation of the Opinion would either undermine these principles or establish rates that would be patently discriminatory, unjust, and unreasonable with regard to retail behind the meter load. First, CAC/EPUC request clarification that the billing determinant for CAS is not equal to the highest monthly demand for the entire period the customer has existed. CAC/EPUC also argue that the finding that retail customer classes with Customer Generation be allocated CAS costs based upon the highest monthly demand would be discriminatory to those retail customer class loads that are engaged in conservation measures or switched from electric

powered loads to natural gas powered loads. CAC/ EPUC advocate that the CAS costs be allocated on a "net load" basis where "net load" is that portion of retail end-use customer load served by electric energy delivered through an interconnected utility or transmission utility to a receipt point.

17. The ISO also filed a request for clarification and/or rehearing. The ISO requests clarification that implementation of changes to the ISO's rate design be implemented prospectively. Additionally, the ISO asserts that the Commission erred in directing that a demand charge be used to assess CAS charges for those customers with behind-the-meter generation who primarily rely on that generation to meet their energy needs if that generation has a 50 percent capacity factor or greater. The ISO states that there are difficulties with implementation of a demand charge being applied to the ISO rate structure that has a current CAS charge that is an energy charge and is based on MWhs. Furthermore, the ISO maintains that it does not possess the data necessary to determine whether a customer with behind-the-meter generation primarily relies on that generation to meet its energy needs or whether the customer has a 50 percent capacity factor. The ISO further contends that it is concerned that applying a demand charge for CAS on only one group of Market Participants may be discriminatory.

2. Commission Determination

18. The rehearing requests regarding our findings regarding the use of CAGL to allocate CAS costs, with the previously cited 50 percent exception, raise a number of points that require clarification and/or rehearing. First, we agree with SoCal Edison that the use of a demand charge for the billing calculation of CAS costs in the past period cannot be implemented for such period. Therefore, the Commission grants rehearing, so that we are not requiring the use of kW demand for allocation. However, we reject SoCal Edison's request that the CAS charge be assessed prospectively on a demand related basis. We clarify that the implementation of any exception to the use of CAGL in this proceeding, effective January 1, 2001, should use kWh load (i.e., an energy-related basis). To do otherwise would create difficult if not insurmountable challenges regarding recalculations of past billings.

19. With respect to the eligibility requirement for the exception to the use of CAGL, i.e., those customers with generators with a 50 percent or greater capacity factor, we concur with the rehearing requests that this exception is not supported by record evidence and will create implementation problems, as indicated by the differing interpretations various parties have raised on rehearing. Therefore, we will grant rehearing so that customers with a 50 percent or greater capacity factor are not eligible for an exception to the use of CAGL.

20. However, we still believe that certain behind the meter generators should be subject to an exception from the use of CAGL for the billing of CAS charges. In light of the

nature of the CAS charges, in particular expenses incurred for the continued planning of operation of the transmission grid, it appears appropriate that generators which are not modeled by the ISO in its regular performance of transmission planning and operation should be exempted from the CAGL charge. That is, those generators that will not cause the ISO to incur administrative or operating expenses should, therefore, have the load exempted from the CAS charge.

21. With respect to the rehearing requests regarding the effective date of changes to the use of CAGL, we agree that the Commission has generally permitted rate design changes to become effective prospectively. However, in this instance we note that one of the primary issues in this proceeding was whether the ISO's rate design was appropriate. Thus, all customers had sufficient notice of possible changes to the ISO's rate design and, by definition, possible surcharges. Accordingly, we believe that it is appropriate to assign a January 1, 2001 effective date to the modified exception to the use of CAGL.[17]

B. PG&E Pass Through Issues

1. New Service and Double Charge

22. As discussed above, Opinion No. 463 affirmed the Initial Decision's holding that PG&E's PTT reasonably recovered, on a dollar-for-dollar basis, the GMC which PG&E has been charged by the California ISO since January 1, 2000. In this context, we held that the PTT represented charges for a new service, charges that PG&E was not recovering by means of its existing CAAs.[18]

23. On rehearing, this conclusion is challenged on various theories by SVP, SMUD, NCPA, Western and Turlock. All of them contest Opinion No. 463's holding that PG&E is performing new services pursuant to the PTT, and maintain that there is no evidence that PG&E is performing services for the affected customers that it was not obligated to perform under its CAAs.[19] SVP argues that that the Commission's finding that PG&E

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[17] In making these changes, we are mindful that the allocation of the GMC charge at issue here is only in effect for a limited period, and that the ISO has taken significant steps to reflect cost causation principles more accurately in its later refinements to the GMC. Thus, the ISO's proposed GMC for 2004 consists of seven distinct charges, which the ISO maintains will "significantly improve the alignment between the cost responsibility of [ISO] customers for GMC charges and the costs they cause the [ISO] to incur." California Independent System Operator Corp., 105 FERC ¶ 61,406 at P 3 (2003).

[18] 103 FERC ¶ 61,114 at PP 50-52.

[19] SVP Request at 12; SMUD Request at 31-33; WAPA Request at 1-27.

performs a new service is erroneously “premised exclusively on the notion that the ISO controls a larger transmission grid than did PG&E prior to the commencement of the ISO’s operations.”[20] NCPA similarly contends that PG&E’s basic service obligation to CAA customers has not been altered, and that the new tariff instead only represents its “increased transaction costs” resulting from regulatory change.[21]

24. The parties make a related argument that because the PTT does not represent the costs for any service not already supplied by PG&E under the CAAs, paying the costs of the new tariff results in double payment for the same services by the CAA customers.[22]

25. The Commission denies rehearing. The parties’ arguments on this issue fail to confront the very foundation of our resolution of this issue. As a Commission staff witness observed, with the formation of the ISO in California, there have been “massive” and “fundamental changes” in the manner in which electricity is sold and distributed there, so that “the complexities of operating the transmission system have increased exponentially.”[23] The ISO GMC and PG&E’s PTT reflect this situation. When NCPA asserts that PG&E is not playing a new role but is attempting to pass through what are merely increased transaction costs under the CAAs,[24] and SVP maintains that the only difference in the ISO’s service is a larger geographic control area, they are looking at isolated elements of roles of the ISO and PG&E, rather than a cohesive whole.

26. We believe that the arguments against the pass through by Scheduling Coordinators of the ISO’s GMC must be addressed in the context of what the GMC is designed to recover. The GMC is based on the ISO’s overarching costs of maintaining the reliability of the ISO transmission grid and operating that grid in the most efficient manner possible, rather than providing any specifically defined transmission. As we explained in Opinion No. 463, the charge includes costs to perform operation studies, system security analyses, emergency management, outage coordination, and transmission planning for the combined ISO grid as opposed to the pre-existing individual control area. Additionally, by combining the pre-ISO control areas and eliminating pancaked rates, the ISO operations allow greater access to generation alternatives so that the ISO can provide ancillary

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[20] SVP Request at 12 (citation omitted).

[21] NCPA Request at 6.

[22] SMUD Request at 31-33; SVP Request at 25-28.

[23] Exh. No. S-1 at 29 (testimony of Mr. Gross).

[24] NCPA Request at 6.

services to the existing transmission contracts in the most cost-effective and efficient manner possible on a broad regional basis. Regional planning and operation of the combined ISO grid maximizes efficiencies when compared to the pre-existing utility operations. Consolidating scheduling maximizes transmission usage, reduces ancillary service requirements and provides greater reliability by allowing the operation of more facilities to respond to contingencies. The customers receiving these new services should pay their share of them.

27. Additionally, the Commission has referred to another benefit supporting the "new service" finding because of the new market opportunities provided by the ISO to existing transmission contract customers outside of their contracts. As the Initial Decision specifically found (and the Commission affirmed):

> Each of the subject CAA customers utilize the ISO-controlled grid, either directly or indirectly, and in fact most of them actively and independently participate in the ISO's new markets. Four of the eight are ISO-certified [Scheduling Coordinators]. This certification enables those parties to participate directly in ISO-managed markets, to sell output from power plants, and to trade power with other Market participants. A fifth CAA customer candidly describes its extra-CAA transactions on the ISO-Controlled Grid. A sixth CAA customer has ad hoc agreements that facilitate sales of energy from its power plants, and sales of demand relief capacity into ISO-managed markets.[[25]]

28. The Commission recognized similar benefits in its orders concerning the Midwest ISO. There, we referred to new market opportunities that would be arising (along with the more efficient, unified operation of the regional grid) which should result in an increased supply of competing generation to load-serving entities such as the existing transmission contract customers, leading to lower overall costs.[26] It is the cost of providing these services – separate, distinct, and qualitatively different from the scheduling and related services PG&E continues to perform within its service territory for its CAA customers – that are included in the ISO's GMC charge, and thus passed through by PG&E in its PTT.

29. Contrary to the allegations of the petitioners, PG&E did indeed present evidence that the costs of the GMC pass through were for the ISO's service, and not the service which PG&E has provided and continues to provide under the CAAs. PG&E witness Mr. Bray specifically explained that the "[ISO] performs certain activities in its role of control

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[25] 99 FERC at 65,166 (footnotes omitted).

[26] See, e.g., Opinion No. 453-A, 98 FERC at 61,412.

area operator which were not performed in the pre-ISO era."[27] He further stated that the ISO's new tasks had a direct impact on PG&E, which "performs on behalf of each and every CAA customer as its ISO-certified [Scheduling Coordinator] . . . a new and unique function that it did not provide to the CAA customers prior to the ISO."[28] He also distinguished the costs charged by PG&E for services performed under the CAAs from the costs that PG&E was passing through to its CAA customers by means of the PTT:

> As [Scheduling Coordinator] for the CAA Customers, PG&E incurs internal costs to provide [this] service. These costs are distinct from the ISO's GMC costs. PG&E (PGAE)[[29]] incurs the ISO GMC to the extent a CAA customer utilizes the services through PG&E (PGAE) as its [Scheduling Coordinator]. PG&E incurs the ISO GMC for each CAA Customer pursuant to the ISO Tariff.[[30]]

Mr. Bray went on to make clear that the ISO's GMC costs were both distinct from and incremental to PG&E's own CAA costs.[31]

30. This evidence was buttressed by PG&E's witness Mr. King, who explained in detail the manner in which he analyzed the company's accounts to demonstrate that "no ISO costs billed to PG&E for ISO [GMC] are included in PG&E's transmission operation and maintenance expense accounts or the [CAAs]."[32] It was also supported by PG&E's witness Mr. Doran, who described in detail PG&E's role as a conduit for the ISO's GMC costs.[33] As Mr. Doran succinctly put it, "the CAA Customers' rates were all in effect prior

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[27] Exh. No. PGE-32 at 16.

[28] Id.

[29] PGAE is PG&E's Scheduling Coordinator identification. According to Mr. Bray, "PGAE is responsible for submitting balanced schedules and meter data directly with the [California] ISO for seven CAA customers plus the WAPA power scheduled to SVP and NCPA." Id. at 15.

[30] Id. at 16.

[31] Id. at 17; 18-34.

[32] Exh. No. PGE-6B (Revised) at 9. See id. at 3-9.

[33] See Exh. PGE-41 at 1-16.

to the commencement of the ISO operations," so that it was "not possible for any of the ISO GMC amounts to be included in these CAA firm transmission rates."[34]

31. In sum, there was clear support in the record for Opinion No. 463's conclusion that PG&E's PTT costs were separate and distinct from the ongoing costs it was charging its customers under the existing contracts.

32. Turlock, alone among the parties seeking rehearing, has an agreement with PG&E that may be viewed as the exception that proves the rule. In 1999, Turlock and PG&E amended their CAA by a settlement approved by the Commission on February 2, 2000.[35] Turlock contends that under the settlement agreement, it was specifically agreed that "PG&E could pass through the GMC charge only to the extent that Turlock 'leaned on' the ISO Controlled Grid (i.e., to the extent that Turlock's actual load exceeded the resources it scheduled to meet that load.)"[36] In our view, the relevant language in the settlement agreement supports Turlock's interpretation. We therefore grant Turlock's request for rehearing on this issue. The other parties requesting rehearing are not able to demonstrate any such post-ISO amendments to their CAAs.

33. The Commission's resolution of the new service issue also disposes of the parties' claim on rehearing of double payment or duplication of services. Because the service represented by the GMC charge is qualitatively different than the services provided by PG&E under the CAAs, no double charge or double recovery by PG&E by means of the GMC is possible. Moreover, as we previously indicated, Mr. Bray specifically examined the terms of the existing CAAs, and concluded that this was not the case:

> [A]s specifically addressed below CAA by CAA, there is no duplication of function or activity between PG&E and the ISO, and any "scheduling" or scheduling-like activity that PG&E performs under the CAAs is unrelated to the ISO activities that give rise to GMC charges. Therefore, the GMC [PTT] does not result in a double charge.[[37]]

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[34] Id. at 3.

[35] Turlock and PG&E settled the complaint brought by Turlock in Docket No. EL98-48-000.

[36] Turlock Request at 11.

[37] Exh. No. PGE-32 at 15. We note that Mr. Bray attempted, unsuccessfully in our view, to characterize the Turlock settlement as authorizing a total pass through of the GMC. Id. at 21.

2. Consistency with Precedent

34. A number of parties attack our conclusion that PG&E is performing a new service as an unexplained and impermissible departure from Commission precedent.[38] They particularly emphasize our decision in Opinion No. 459[39] as inconsistent with the result here. For example, NCPA argues that in Opinion No. 459, "[t]he Commission rejected PG&E's argument that the proposed-pass through -- PG&E's so-called 'R[eliability] S[ervices] Tariff'-- represented a 'new service' for which PG&E was entitled to collect rates" in addition to the charges it made for firm service under NCPA's existing contract, while in this case, the Commission permitted just such an extra charge.[40] SMUD argues that our approach here also conflicts with Opinion No. 458,[41] where the Commission held that "customers who self-provide services" under existing contracts "must not be double-charged for those services."[42] Additionally, NCPA argues that Opinion No. 463 "completely ignores" the Midwest ISO Remand Order, which "directly addresses the issue of whether ISO/RTO administrative costs can be passed through to entities that hold grandfathered transmission contracts."[43] In NCPA's view, the Remand Order's conclusion that such costs can be passed through by means of such contracts is incompatible with our decision here that the ISO GMC costs should not be passed through the CAAs, but through a new tariff for a different service.

35. The Commission rejects these arguments. While the Commission determined that the ETC and TO Tariff customers should both be allocated the RS costs, we affirmed the Initial Decision's finding that PG&E had failed to support the recovery of RS costs from either of these customer classes.[44] With respect to the ETC customers, Opinion No. 459

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[38] See NCPA Request at 12-16; SMUD Request at 34-38; SVP Request at 13-14.

[39] Pacific Gas & Electric Co., 100 FERC ¶ 61,160 (Opinion No. 459), reh'g denied, 101 FERC ¶ 61,139 (2002) (Opinion No. 459-A).

[40] NCPA Request at 14-15 (footnote omitted).

[41] Pacific Gas and Electric Co., et al., 100 FERC ¶ 61,156, reh'g denied, 101 FERC ¶ 61,151 (2002) (Opinion No. 458-A).

[42] SMUD Request at 37.

[43] NCPA Request at 14 (footnote omitted).

[44] In Opinion No. 459, the Commission affirmed an Initial Decision denying recovery of Reliability Service (RS) charges by PG&E from either its ETC customers or its TO Tariff customers. It also deserves mention that in Opinion No. 459, we reversed the

(continued…)

explained that firm transmission contracts executed prior to the California restructuring inherently included reliability as part of that firm service. Thus, the Commission concluded that "PG&E's proposal to add an allocation of Cal ISO RS charges to the unadjusted rates of the ETC customers is not just and reasonable because it results in a double recovery."[45]

36. We find that Opinion No. 459 is consistent with our decision here. While the existing contracts at issue in that case inherently included reliability as part of firm service, as we have explained in some detail above, the CAAs at issue here did not and could not have included the service represented by the ISO's GMC charge.

37. The parties' reliance on Opinion No. 458 likewise stems from a false factual assumption. The services there with which we were concerned about double charging were those which were indeed self-provided by the contract customers. In Opinion No. 463, however, as discussed above, the very premise of our reasoning was that the parties could not self-provide such services under their CAAs, but that only the ISO could provide the services in question in the new, post-ISO world. Thus, Opinion No. 458 is in complete harmony with Opinion No. 463.

38. Finally, the Commission rejects the claim that our approach in Midwest ISO cannot be reconciled with Opinion No. 463. First, while both of these cases involve the manner in which ISO administrative costs can be passed through, it does not follow that what is reasonable and appropriate for the Midwest ISO cost adder is necessarily so for the

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(…continued)

judge's finding that certain of the charges in question did not benefit grid-wide reliability and thus should not be allocated to all customers. Rather, we held, because both ETC and TO Tariff customers benefit from RS, "both classes of customers should be allocated a portion of PG&E's RS costs." Opinion No. 459, 100 FERC ¶ 61,160 at P 16. We further held that PG&E's proposal to allocate these costs to all customers "based on each customer's overall load as a percentage of the total load served from PG&E's transmission system" was reasonable. Id.

[45] Id. at P 20. Opinion No. 459 went on to hold that while the TO Tariff provides for such post-restructuring unbundled transmission service, and that record did not demonstrate that the TO Tariff rates already recovered this type of expenses, PG&E had failed to supply appropriate cost support to recover the RS costs in the TO Tariff rates.

California ISO GMC. Indeed, the costs at issue differ significantly because of the different division of responsibilities that has developed in the two regions. For example, while the pre-existing control areas in California were consolidated under the ISO, the individual control areas in the Midwest ISO remain largely intact. Thus, while in California the ISO is performing all control area functions, in the Midwest ISO most control area responsibilities remain with the individual transmission owners.

39. Additionally, there may well be appropriate reasons to require different recovery of ISO administrative costs by transmission owners from their customers in the two regions. However, at this point the question remains academic. Because transmission providers in the Midwest ISO have not filed to recover the ISO's overhead costs (either through a separate tariff like PG&E or through individual existing transmission contracts), the Commission has not had the opportunity to address the issue in that context.

3. The MO Component

40. The Initial Decision held that the PTT should not include the MO component of the GMC because it did not constitute a new service for the CAA customers. In the judge's view, the MO component was only assessed by the ISO for ancillary services procured through the ISO markets, while those services were being self-provided by the CAA customers. Opinion No. 463 reversed the Initial Decision on this point. The Commission determined that, based on the record, the ISO's MO services under the ISO Tariff are indeed separate and distinct from the services under the CAA.

41. Modesto, NCPA and SVP contend that Opinion No. 463 erred in reversing the Initial Decision on this issue. SVP, for example, while conceding that the ISO's "GMC does not include a charge for the ISO's provision of Ancillary Services per se," argues that the allocation of the MO component is "directly based upon the amount of Ancillary Services the ISO provides, since Ancillary Services are the billing determinant for the MO bucket of the GMC."[46] Because CAA customers who self-provide ancillary services "do not 'lean' on the ISO for Ancillary Services," SVP reasons, "such customers do not cause the ISO to incur costs with respect" to such services.[47]

42. The Commission will deny rehearing. Once again, the parties objecting to the pass through have failed to recognize the qualitative difference between the nature of the ISO's services and the services that PG&E has been and is continuing to provide under the CAAs. First, the MO charges are for the costs the ISO incurs in administering the markets

[46] SVP Request at 33, citing Tr. 3011-2013 (Mr. Doran).

[47] Id. at 34.

established as a result of the California restructuring. These costs did not exist prior to the creation of the ISO, because the markets did not yet exist. Second, the costs at issue here are the operating costs for providing ancillary services, not the provision of the ancillary services themselves. Finally, as the ISO Tariff itself indicates, the MO charge is only assessed on a Scheduling Coordinator when it procures such services through the ISO markets.[48] The tariff further provides that a Scheduling Coordinator's responsibility for these costs is reduced by other, self-provided ancillary services.[49] In sum, the parties' claim of being charged twice for the same service cannot be sustained.

C. SDG&E Request for Rehearing and Complaint Regarding the GMC as Applied to Portions of the Southwest Powerlink

43. SDG&E's request for rehearing focuses on the propriety of the GMC as applied to the energy schedules on portions of the Southwest Powerlink (SWPL), owned by Arizona Public Service Company (APS) and the Imperial Irrigation District (IID).

44. SWPL is a 292-mile 500 kV transmission line from the Palo Verde switchyard in Arizona to SDG&E's Miguel substation near San Diego. Pursuant to contracts (Participation Agreements) executed in 1981 and 1983, SDG&E transferred portions of SWPL to APS and IID resulting in SWPL being jointly owned by SDG&E, APS and IID.[50] Under the terms of the Participation Agreements, each joint owner has priority to the unused capacity in the other owner's shares. APS and IID both operate and control their own portions of SWPL and each determine what resources are to be scheduled over their portions of SWPL.[51] Although SWPL itself is within the ISO Control Area, none of the load served by APS and IID over their portions of SWPL lie within the ISO Control Area. APS uses its portion of SWPL to deliver energy to its retail load at APS' North Gila

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[48] ISO Tariff § 8.3.3 (Exh. J-2).

[49] Id. at § 2.5.20.2.

[50] The Palo Verde-North Gila segment of SWPL is owned jointly by SDG&E, APS and IID in the ratio of 72.22%, 11% and 12.78%, respectively; and the North Gila-Imperial Valley segment is owned by SDG&E and IID in shares of 85.64% and 14.36%, respectively.

[51] SDG&E states that APS is the operator of a substantial portion of the SWPL within Arizona (i.e., APS has the ultimate authority to decide the physical transfer capability of the line, or whether to place the line in service). SDG&E Rehearing Request at 8-9.

substation in Arizona. IID uses its portion of SPWL to deliver energy to its retail load in the Imperial Valley at the Imperial Valley substation.[52]

45. SDG&E states that it is a Participating Transmission Owner (PTO) under the California ISO Tariff, and has conveyed to the ISO operational control of SDG&E's transmission rights and facilities, including its rights in SWPL. SDG&E states that, as a PTO, it must submit to the ISO's direction with respect to the timing and content of its energy schedules, and to reliability operations on SDG&E-owned facilities. SDG&E is contractually bound to submit schedules for APS and IID to the ISO under their individual Participation Agreements and the ISO bills SDG&E for the GMC on the APS and IID SWPL schedules. However, SDG&E states that the current provisions of the contract do not provide for reimbursement for that portion of the ISO's GMC charges attributable to the APS and IID schedules.[53]

46. In the ER01-313-000 GMC proceedings, the ISO proposed to assess the MO component of the unbundled GMC to SDG&E as Scheduling Coordinator for the APS and IID schedules on their respective ownership shares of SWPL.[54] The MO charge includes the ISO's administrative costs of providing Imbalance Energy, which is needed when an entity's schedule is not perfectly balanced, for instance where there are line losses occurring where the energy enters the ISO control area and where the energy leaves the ISO control area. SDG&E is assessed the administrative costs of providing this Imbalance Energy for losses associated with SWPL Energy[55] under the MO charge.

47. SDG&E opposed imposition of the MO charge on energy scheduled by APS and IID over their respective shares of SWPL because: (a) neither APS nor IID had transferred its portion of SWPL to the ISO operational control and thus the ISO could not properly impose the MO Charge on the APS and IID SWPL schedules; and (b) the subject APS and IID energy schedules do not require the ISO to procure Imbalance Energy, eliminating the need for the ISO to purchase such energy, because, under an arrangement with the ISO, SDG&E self-provides energy to cover any imbalances attributable to SWPL Energy. The ISO responded that, contrary to SDG&E's claim, SWPL uses facilities under the ISO's

[52] SDG&E Rehearing Request at 8.

[53] Id. at 9.

[54] Prior to January 1, 2001, the ISO had not charged GMC to such schedules.

[55] SWPL Energy is energy schedules by non-ISO co-owners on their respective portions of the SWPL.

operational control and therefore is appropriately assessed the MO component of the GMC.

48. In the Initial Decision, the Presiding Judge found that it was reasonable for SDG&E to be assessed the MO charge for the administrative costs of providing Imbalance Energy for losses associated with SWPL Energy.[56] The Presiding Judge stated that the reason SDG&E is assessed these costs is based on the ISO's billing determinant for the MO charge (i.e., total purchases and sales of Imbalance Energy).[57] The Presiding Judge explained that "[w]hether 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 MO charge . . . . [Here] the MO charge is assessed on small purchases of imbalance energy to replace line losses on SWPL Energy in the ISO Control Area."[58] The Presiding Judge found that "it is just and reasonable for SWPL Energy schedules to be assessed a share of the MO charge in this manner."[59] Further, to the extent SDG&E self-provides the correct amount of Imbalance Energy, it will not be charged; SDG&E is only charged for real-time energy imbalances that can and do occur. In a footnote, the Presiding Judge referred to a statement from the ISO's January 25, 2002, initial brief, explaining that:

> The ISO has an arrangement with SDG&E whereby SDG&E estimates the amount of Imbalance Energy necessary to cover SWPL Energy losses, and thereby self-provides Imbalance Energy losses. To the extent these estimates are not precisely accurate, however, certain additional Imbalance Energy may be necessary from time to time. It is for this additional Imbalance Energy that SDG&E is assessed the MO charge for SWPL energy.[60]

Opinion No. 463 summarily affirmed the Initial Decision on this issue.

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[56] 99 FERC at 65,136.

[57] Id.

[58] Id.

[59] Id.

[60] Id. at n.130 (citation omitted). See also ISO February 22, 2002 Reply Brief, at 63, n.43.

1. The ISO's Motion to Correct the Record

49. On August 8, 2002, the ISO filed a Motion to Correct the Record, stating that inaccuracies existed in the record with regard to how it assesses SDG&E the MO charge for SWPL Energy. The ISO explained that, contrary to statements in its briefs to the Presiding Judge that the ISO assessed the MO charge only on any real-time Imbalance Energy necessary to cover line loses, the ISO actually assessed the charge on Energy scheduled by SDG&E to cover line losses as well. In other words, the MO charge was assessed by determining the difference between the pre-scheduled load/generation to cover line losses and the actual line losses that occurred, that is, the net difference. However, while this is how the quantity of actual Imbalance Energy needed to meet the difference between load and generation is determined for settlement of the sale of such energy, the billing determinant for the MO charge is based on "total purchases and sales," that is, on the gross Imbalance Energy components of a transaction.

50. SDG&E was the only party to file an answer to the ISO's motion, asking that the Commission give effect to the Initial Decision's finding that the ISO's crediting SDG&E's self-provision of Imbalance Energy was just and reasonable. SDG&E noted that while the motion explained how the ISO actually calculates the MO charge, it did not explain why the ISO does not credit, or net against the billing determinant the amounts of Imbalance Energy self-provided. SDG&E also requested an order requiring the ISO to issue refunds of all GMC it assessed on SWPL Energy or, in the alternative, SDG&E asked the Commission to credit SDG&E's self-provision of Imbalance Energy retroactive to January 1, 2001.

51. The Motion to Correct the Record and SDG&E's response were addressed neither by the Presiding Judge nor Opinion No. 463.

2. SDG&E's Request for Rehearing

52. On June 2, 2003, SDG&E filed a request for rehearing of Opinion No. 463 stating that the Commission improperly applied the CAS component of the GMC to the SWPL schedules. SDG&E reiterates that neither APS nor IID serve any load within the California ISO Control Area. SDG&E argues that the costs underlying the GMC are not caused by APS and IID SWPL schedules because APS and IID import energy over SWPL from outside the ISO control area to their respective loads, also outside the CAISO control area. SDG&E argues that any such costs related to these SWPL schedules are properly borne by the load within the ISO control area due to the benefits of interconnected operation with other control areas.

53. SDG&E argues that charging GMC to the transactions violates the ISO's Tariff because the transactions do not take place on the ISO controlled grid. SDG&E states that

the ISO, in responding to SDG&E's dispute over the charges, justified them because the transactions are "wheel-through," which by tariff definition can only take place on the ISO controlled grid. SDG&E states that the GMC-related costs the ISO attributes to the APS and IID SWPL schedules are part of the reciprocal support each WSCC control area has always provided to other WSCC control areas. SDG&E argues that such costs are attendant to meet the WSCC's reliability requirements, and the cost of providing this mutual support was borne by each control area as a necessary cost of interconnected operations. SDG&E states that it is therefore inappropriate for the ISO to shift to other control areas costs that were previously deemed "paid for" with reciprocal support and services.

54. SDG&E argues that the GMC is inappropriately applied to the SWPL shares of non-ISO participants, whose respective loads lie outside the ISO Control Area, and thus does not trigger any of the considerations Opinion No. 463 cites for assigning GMC to the behind-the-meter loads within PG&E's service territory.

55. Further, SDG&E asserts that the ISO, contrary to its representations to the Commission, has failed to credit SDG&E's self-provision of Imbalance Energy against the billing determinant for the MO component of the GMC as applied to SWPL Energy. While SDG&E did not object to the crediting of its self-provision, SDG&E's exceptions took the position that it was improper for the ISO to apply any GMC to SWPL Energy.

3. SDG&E's Complaint: Docket No. EL03-131-000

56. On June 2, 2003, SDG&E also filed a complaint and request for fast track processing with the Commission under Section 206 of the Federal Power Act (FPA)[61] and Sections 206 and 217 of the Commission's Rules of Practice and Procedure.[62] In its complaint, SDG&E requests that the Commission issue an order directing the ISO to honor and adhere to its filed and Commission-accepted rate, and to refund to SDG&E, with interest, amounts improperly levied on SDG&E regarding the GMC associated with schedules on portions of the SWPL owned by APS and the IID, in excess of that filed rate. SDG&E asserts that refunds should be based on the rate approved in Opinion No. 463 and the tariff provision placed in effect by the Commission's December 29, 2000 Order accepting the ISO's unbundled GMC.[63]

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[61] 16 U.S.C. §824e (2000).

[62] 18 C.F.R. §§ 385.206, 385.217 (2003).

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

57. SDG&E states that the ISO's failure to credit SDG&E's self-provision of Imbalance Energy against the MO charge, together with its misrepresentations to the Commission regarding this issue, violates not only the ISO's filed rate, but violates the minimum standards of practice before the Commission. SDG&E argues that under Section 205 of the FPA, the ISO is legally bound to follow its filed tariff, including the crediting of SDG&E's self-provision of Imbalance Energy, until the Commission modifies the tariff, or the ISO makes a new filing under Section 205 modifying the tariff interpretation. Thus, SDG&E states that the ISO must give it the self-provision credit effective January 1, 2001, and to refund, with interest, amounts SDG&E has paid to the ISO for the MO charge, except for any amounts not covered by SDG&E's self-provision of Imbalance Energy.

58. SDG&E states that the Commission should also award SDG&E's costs, including attorneys' fees because the ISO's failure to correct the record and related misconduct over many months is inexcusable, has put it to substantial expense, and appears to be calculated to obtain for the ISO a conclusive procedural advantage on this issue. SDG&E states that, as the Presiding Judge stated in the 2002 GMC Proceedings, the ISO's conduct, testifying to one practice and following another, merits sanctions.[64]

59. SDG&E also requests that the Commission address this complaint without consolidating it with the ER01-313-000 dockets. In specific, SDG&E states that its request for rehearing of Opinion No. 463 seeks to reverse the ISO's imposition of the GMC on SWPL Energy and argues that the GMC is unjust, unreasonable, and unduly discriminatory as applied to SWPL Energy. SDG&E argues that the rehearing request seeks refunds of the entire amount of GMC SDG&E has paid for SWPL Energy to the extent not already refunded in its complaint proceeding. It states that, in contrast, SDG&E's complaint is based on the ISO's violation of its filed rate, and seeks refunds only of those amounts of the MO charge that were offset by SDG&E's self-provision of Imbalance Energy.

4. Commission Determination

60. As stated above, under the Participation Agreements, SDG&E is contractually bound to submit schedules for APS and IID to the ISO. The ISO bills SDG&E for the administrative costs of processing those schedules through the MO component of the GMC. Specifically, the MO component is assessed to SDG&E to recover administrative costs associated with the procurement of the Imbalance Energy necessary to account for transmission line losses for the SWPL schedules.

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[64] SDG&E Complaint at 25, citing Docket No. ER02-250-000, May 30, 2002 prehearing conference, Tr. at 148:2-10.

61. The SWPL schedules are wheel-through transactions. The generation, which originates outside the ISO control area, is imported and transmitted over ISO grid facilities and subsequently exported to serve APS and IID's load. According to the ISO, there are Imbalance Energy requirements associated with those schedules to cover the differences between scheduled losses and actual transmission line losses. However, while SDG&E characterizes their arrangement with the ISO as a crediting arrangement for the procurement of energy for losses, the ISO characterizes it more as a load accommodation. We view the dispute between SDG&E and the ISO as a misunderstanding over the semantics of the arrangement the ISO has with SDG&E to self-provide Imbalance Energy necessary to cover transmission line losses.

62. We note that regardless of the characterization, the overall effect of the arrangement is to reduce SDG&E's exposure to the Imbalance Energy market. Scheduling Coordinators in California are required to submit balanced schedules such that each Scheduling Coordinators' generation resources match the load that it serves. Although SDG&E is submitting schedules for loads outside the ISO-control area, the ISO still needs to match generation resources for that load. Through the load accommodation, the ISO allows SDG&E to schedule additional load to match the generation for the SWPL schedules. The additional load and accompanying generation serve to offset actual line losses by allowing SDG&E to reasonably estimate and self-provide the imbalance energy necessary to cover the line losses.

63. SDG&E asserts that the Presiding Judge upheld the ISO's proposal to apply the MO charge to Imbalance Energy relating to SWPL schedules, specifically based on the ISO's crediting SDG&E's self-provision of Imbalance Energy against the MO component of the GMC. We disagree. The Presiding Judge did not specifically reference the ISO's crediting in the Initial Decision. However, the Presiding Judge did find that the amount of Imbalance Energy necessary to cover line losses would be small because SDG&E, through its arrangement with the ISO, could estimate and self-provide the necessary Imbalance Energy needed to cover the line losses. The Presiding Judge also found that SDG&E would not be assessed any MO charges to the extent that its estimates were accurate. Thus, the Initial Decision concluded that SDG&E would only be assessed the administrative costs associated with real-time imbalances that can and do occur.[65] It further explained that SDG&E would never be able to totally reduce its exposure to the Imbalance Energy market and, would therefore always rely on the ISO for small amounts of Imbalance Energy, subjecting SDG&E to any attendant administrative costs. We find that this is a reasonable arrangement.

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[65] 99 FERC at 65,136.

64. In its Motion to Correct the Record, the ISO distinguished between the settlement of energy in the Imbalance Energy market and how it was subsequently billed. Specifically, the ISO determines the amount of Imbalance Energy necessary to accommodate a schedule on a net basis (i.e., it determines the difference between the pre-scheduled load/generation to cover line losses and the actual line losses that occurred). However, the billing determinant for the MO charge is based on total purchases and sales of Imbalance Energy. We find that the ISO has provided no justification for settling the energy on a net basis while assessing the MO component on a gross basis. Assessing the MO component to the total purchases and sales of Imbalance Energy fails to adequately recognize SDG&E's self-provision of Imbalance Energy. Accordingly, we will require the ISO to assess the MO component of the GMC on the net amount of Imbalance Energy needed to cover the line losses associated with the SWPL schedules. Thus, effective January 1, 2001, the ISO must refund, with interest,[66] any administrative costs collected from SDG&E associated with the SWPL schedules in excess of the administrative costs associated with the net amount of Imbalance Energy actually required under the schedules.

65. The Commission finds that SDG&E's complaint raises essentially the same issues that are addressed in the rehearing. In light of our decision above, we will dismiss SDG&E's complaint in Docket No. EL03-131-000 as moot. Because of our disposition of the case, the Commission finds that the ISO's Motion to Correct the Record is also moot, and we deny it on that basis. Further, we deny SDG&E's request to impose monetary sanctions on the ISO on the merits. The Commission has opined that, while it believes that it has the authority to award monetary sanctions,[67] such sanctions are an extraordinary remedy and should be imposed only in the "clearest cases."[68] In our view, the ISO's conduct here does not present the clear case needed to warrant the imposition of the requested sanctions.

D. Billing of Qualifying Facilities and Governmental Entities

66. The Initial Decision found that the ISO should directly bill Qualifying Facilities (QFs) and certain Governmental Entities for the CAS charge for their behind-the-meter

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[66] Interest should be calculated consistent with Section 35.19a of the Commission's regulations. 18 C.F.R. ' 35.19(a)(a)(2) (2003).

[67] 18 C.F.R §385.411 (2003).

[68] Connecticut Yankee Atomic Power Co., 81 FERC ¶ 63,006 at 65,038 (1997), citing Pennsylvania Power Co., 21 FERC ¶ 61,313 at 61,821 (1982). See also Central Illinois Public Service Co., 27 FERC ¶ 61,079 at 61,145 (1984).

load, rather than billing Scheduling Coordinators.[69] Opinion No. 463 did not address this issue.

67. The ISO states in its request for rehearing that QFs operating under the umbrella of a Scheduling Coordinator should be billed through the Scheduling Coordinator that schedules standby service for their load. The ISO observes that the responsibilities of a Scheduling Coordinator extend to paying charges in accordance with the ISO Tariff, and that loads receiving standby service from a Utility Distribution Company are Scheduling Coordinator-metered entities. According to the ISO, the arrangement by which Scheduling Coordinators act as billing representatives for their customers is a foundational element of the ISO's structure as a centralized transmission provider and adds a great amount of efficiency and cost savings to the ISO's operations.

68. The ISO states that under this structure, the ISO only has to prepare bills for about 80 Scheduling Coordinators. If required to implement direct billing ordered by the Initial Decision, the ISO would have to break out charges for and directly bill several hundred separate entities. The ISO states that its finance and billing department could not possibly administer this increased workload without substantial increases in staff or new computer systems to automate the billing. Similarly, the ISO states that the ISO has no anticipation that entities provided such bills would pay them willingly.

69. The ISO is also seeking rehearing, with regard to billing Governmental Entities directly for their behind-the-meter load not otherwise scheduled. The ISO once again argues that the GMC should be assessed to the entities that act as the Scheduling Coordinators for those entities. The ISO explains that entities that schedule on the ISO-Controlled grid in accordance with existing contracts or interconnection agreements have not entered into an agreement with the ISO.

70. The ISO states that under Section 2.3 of its Responsible Participating Transmission Owner Agreement, PG&E has agreed to be the Scheduling Coordinator for certain Governmental Entities with which it has existing contracts. The ISO states that while arguments have been made that a Responsible Participating Transmission Owner is only a Scheduling Coordinator to the extent that it actually schedules energy for a load with generation behind a meter, no such limitation appears in the Responsible Participating Transmission Owner Agreement. Moreover, the ISO argues that such a limitation would make little sense given that the existing contracts identified in the Agreements may require the Governmental Entity and Responsible Participating Transmission Owner 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.

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[69] 99 FERC at 65,145-46.

71. The ISO states that since it has assumed the functions of the Control Area Operator, but not the assignment of the Existing Contracts, it must rely upon the former control area operator (i.e., the Participating Transmission Owner that is the contracting party for the Existing Contract) to fulfill its responsibilities under the Existing Contracts and to ensure the Governmental Entities fulfill theirs. The ISO asserts that these responsibilities pertain to the entire load of the Governmental Entity, not just to the portion scheduled, and that the appropriate Commission-approved agreements are in place to allow the Scheduling Coordinators for the Governmental Entities to be the billing representatives for those entities' entire portion of the GMC, including any portion assessed on behind-the-meter load.

72. Therefore, the ISO requests determination that, consistent with its tariff, it should be authorized to bill the GMC to Scheduling Coordinators of Qualifying Facilities and Governmental Entities.

73. The Commission will grant rehearing. We agree with the ISO that the Scheduling Coordinator is the appropriate entity to be billed, since the Scheduling Coordinator acts as the billing representative for the customers it serves. As such, the Scheduling Coordinator is obligated to pay the ISO's charges in accordance with the ISO Tariff. [70] To the extent that a QF is utilizing a Scheduling Coordinator, that QF should be billed by the Scheduling Coordinator that schedules standby service for that load. With regard to Governmental Entities, under the relevant Responsible Participating Transmission Owner Agreement, each Governmental Entity has an arrangement with regard to existing contracts that utilizes a Scheduling Coordinator. Accordingly, the Scheduling Coordinator is the appropriate party to be billed.

The Commission orders:

(A) The requests for rehearing and/or clarification of the ISO, SoCal Edison, MID, California PUC, SMUD, Turlock and CAC/EPUC are hereby granted, to the extent described in the body of the order.

(B) The request for rehearing of Turlock with respect to the PTT is hereby granted.

(C) Except as stated in Ordering Paragraphs (A) and (B), all of the requests for rehearing and/or clarification are hereby denied.

(D) SDG&E's complaint is hereby dismissed as moot.

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[70] See § 2.2.6.1 of ISO Tariff (Obligation to Pay).

(E) Any motions or requests filed by the parties and not specifically referred to herein are hereby denied.

(F) The ISO is hereby directed to file a refund report, within 30 days of the date of this order that is consistent with the discussion herein.

By the Commission. Commissioner Kelliher dissenting in part with a separate statement attached.

(S E A L)

Linda Mitry,
Acting Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	Docket No. ER01-313-003
Pacific Gas and Electric Company	Docket No. ER01-424-003
San Diego Gas & Electric Company v. California Independent System Operator Corporation	Docket No. EL03-131-000

(Issued January 23, 2004)

Joseph T. KELLIHER, Commissioner *dissenting in part*:

1. I dissent from the section of the order that finds that PG&E is performing a new service for its wholesale transmission contract customers, known as Control Area Agreement (CAA) customers, effectively allowing PG&E to pass through to them certain California Independent System Operator (ISO) charges. In my view, the transmission service that these CAA customers receive is not a new service warranting the imposition of costs that would otherwise be unrecoverable under the existing transmission contracts.

2. Much of the Commission's new service reasoning rests on the assertion that the CAA customers benefit from "new market opportunities provided by the ISO to existing transmission contract customers outside of their contracts."[1] I find this argument unpersuasive. At hearing, the Commission's Trial Staff concluded that there is no new service justifying pass through of the Grid Management Charge (GMC) to CAA Customers because no new benefit is conferred under the Pass-Through Tariff and the

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[1] California Independent System Operator Corporation et al., Docket No. ER01-313-003 (January 23, 2004), at Par. 27.

CAA Customers do not receive anything above and beyond the service PG&E used to provide.[2] According to Trial Staff, "[A]ll that has changed is the manner in which service is procured for the same CAA Customers. PG&E is procuring service from a new control area operator (the ISO) instead of providing the service itself as a control area operator."[3] I agree.

3. In addition, I disagree with the Commission's decision with respect to the Market Operations component of the GMC. The Administrative Law Judge's Initial Decision held that the Pass-Through Tariff should not include this component in the GMC because it did not constitute a new service for the CAA customers. The Commission reversed the ALJ's Initial Decision on this point, and this order affirms that reversal. I believe that the ALJ's Initial Decision was correct.

4. Throughout the development of independent system operators and regional transmission organizations, the Commission has had a policy of honoring existing transmission contracts. This is true even though the Commission has the authority to reform contracts when it finds that doing so is in the public interest.

5. The Commission also has had a competing policy goal, namely preventing "trapped costs" at independent system operators and regional transmission organizations. I agree that we should try to minimize or avoid "trapped costs." However, I simply do not think the new service rationale is a sound basis for doing so in this circumstance. Accordingly, I would grant rehearing on this new service issue.

Joseph T. Kelliher

[2] California Independent System Operator Corporation et al., 99 FERC ¶ 63,020 at 65,161 (2002).

[3] Id. at 65,165.