United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued February 26, 2008 Decided May 2, 2008

No. 04-1090

WESTERN AREA POWER ADMINISTRATION,
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT

SOUTHERN CALIFORNIA EDISON COMPANY, ET AL.,
INTERVENORS

Consolidated with
04-1095, 06-1362, 06-1370, 06-1371, 07-1081

On Petitions for Review of an Order of the
Federal Energy Regulatory Commission

Mark W. Pennak, Attorney, U.S. Department of Justice, and *Harvey L. Reiter* argued the cause for petitioners Western Area Power Administration, et al. With them on the briefs were *Glen L. Ortman*, *Lucy Holmes Plovnick*, *M. Denyse Zosa*, *Wallace Lamar Duncan*, *Sean M. Neal*, *James D. Pembroke*, *Derek Anthony Dyson*, *William S. Huang*, and *Meg Meiser*. *Anthony A. Yang and Robert S. Greenspan*, Attorneys, U.S. Department of Justice, and *Robert C. McDiarmid*, *Lisa S. Gast*, and *Peter J. Scanlon* entered appearances.

Rod S. Aoki argued the cause for petitioners Cogeneration Association of California and Energy Producers and Users Coalition. With him on the briefs were *Michael Alcantar* and *Donald Brookhyser*.

Samuel Soopper, Attorney, Federal Energy Regulatory Commission, argued the cause for respondent. With him on the briefs were *Cynthia A. Marlette*, General Counsel, and *Robert H. Solomon*, Solicitor. *Patrick Y. Lee*, Attorney, entered an appearance.

Kerry C. Klein argued the cause for intervenors. With her on the brief were *Michael E. Ward*, *Mark D. Patrizio*, and *Jennifer L. Key*. *Anthony J. Ivancovich* and *Bradley R. Miliauskas* entered appearances.

Before: RANDOLPH and GARLAND, *Circuit Judges*, and EDWARDS, *Senior Circuit Judge*.

Opinion for the Court filed by *Senior Circuit Judge* EDWARDS.

EDWARDS, *Senior Circuit Judge*: This case arises from the reorganization of the electric transmission grid in the state of California, the subsequent imposition of administrative fees by the California Independent Systems Operator ("ISO"), and the pass-through of those fees by Pacific Gas and Electric ("PG&E") to its customers. The decision of the Federal Energy Regulatory Commission ("FERC" or "Commission") to approve the fees and pass-through has been challenged by several large customers of PG&E – the Western Area Power Administration, Northern California Power Agency, Sacramento Municipal Utility District ("SMUD"), City of Santa Clara, and Modesto Irrigation District (together "Existing Customers") – as well as the Cogeneration Association of California and the Energy

Producers and Users Coalition (together "CoGen"). The petitioners argue that the Commission acted arbitrarily and capriciously in approving fees that violated FERC cost-causation principles and imposed new fees for existing services, in violation of the *Mobile-Sierra* doctrine.

We uphold the Commission's Order against both sets of challenges. CoGen's petition to this court was untimely. Subject matter jurisdiction over challenges to a FERC order is limited to petitions that are filed within 60 days of the challenged order. 16 U.S.C. § 825*l*(b). Because CoGen did not file its petition within that time frame, we cannot review its merits. While we have jurisdiction over the petition of the Existing Customers, we find that the Commission did not act arbitrarily or capriciously in its approval of the California ISO's fees or the PG&E pass-through. We therefore uphold the decision of the Commission.

I. BACKGROUND

In 1996, FERC inaugurated a "brave new regulatory world" with Order No. 888. *East Kentucky Power Coop., Inc. v. FERC*, 489 F.3d 1299, 1301-02 (D.C. Cir. 2007). This Order was "[p]romulgated in response to the anticompetitive effects of vertical integration" where generation of electricity and transmission of electricity was controlled by the same entity. *Id.* at 1302. The Order attempted to increase competition in the electricity business by "requir[ing] the functional unbundling of wholesale generation and transmission services." *Id.* (quotation marks omitted). We have described Order No. 888 as follows:

> If vertical integration (the predecessor to functional unbundling) offered a *prix fixe* menu of utility services, functional unbundling required the *a la carte* alternative: Under the new system, previously integrated utilities were now required to maintain a wholesale marketing function separate from their transmission functions. . . .

> In addition to the unbundling requirements that it imposed, Order No. 888 encouraged, but did not demand, the formation of Regional Transmission Organizations ("RTOs"): multi-utility entities that could manage all transmission services for a particular region. . . . FERC suggested a further improvement to the novel system it envisioned[:] The multi-utility RTO would cede operational control of its collectively run transmission facilities to an [ISO], which would have no financial interest in generation services and therefore no incentive to thwart FERC's goals of efficiency, competition, and improved reliability.

Id.

As the Commission was implementing Order No. 888, the State of California chartered the California ISO as "an independent entity that would take over transmission operations from California utilities." *Sacramento Mun. Util. Dist. v. FERC*, 428 F.3d 294, 296-97 (D.C. Cir. 2005). Upon taking over the transmission grid, the California ISO would provide transmission services on a nondiscriminatory basis. Prior to the transition to the ISO, the three major privately-owned utilities – PG&E, Southern California Edison, and San Diego Gas & Electric – each had operated its own control area, performing the coordination, administrative, and maintenance duties needed to operate a reliable power system. Contracts between PG&E and the Existing Customers, collectively referred to as the Control Area Agreements, date to the time when PG&E held responsibility for its control area. Upon the creation of the California ISO, the privately-owned utilities became participating transmission owners in the new system by turning over control of their transmission facilities to the ISO. After that transition, certain services contracted for by the Existing Customers in the Control Area Agreements with PG&E were provided by the California ISO.

In 1997, the California ISO filed its original proposed Grid Management Charge which was designed to recover its start-up, administrative, and operating costs. Letter from Charles Robinson, General Counsel, California ISO, and Edward Berlin, Swidler Berlin Shereff & Friedman, to David P. Boergers, Secretary, FERC (Nov. 1, 2000) at 1, *reprinted in* Joint Appendix ("JA") 86. This charge was assessed on a monthly basis against all ISO Scheduling Coordinators – the entities that are responsible for scheduling electricity deliveries through the ISO. *Id.* Under the new system, PG&E has been the Scheduling Coordinator for the Existing Customers for all relevant time periods.

In November 2000, the California ISO proposed a new Grid Management Charge for the period from January 1, 2001 to January 1, 2004. The revised Grid Management Charge "unbundled" the earlier charge in order to "allocate costs fairly among all ISO system users, and minimize cost subsidization among" participants in California's electrical market. *Id.* at 6, JA 91. The ISO believed that unbundling the Grid Management Charge would better reflect "the principle of cost causation" which it defined as meaning that "the ISO's costs, to the extent possible, should be attributed to those entities that caused them to be incurred." *Id.* Tying fees closely to cost causation facilitates market efficiency because more accurate "price signals direct[] market behavior towards optimum results." *Id.*

The Grid Management Charge was unbundled according to three categories of services that the ISO provides: Control Area Services, Inter-Zonal Scheduling, and Market Operations. *Control Area Services* are the services that the ISO provides as a Control Area operator to ensure "reliable, safe operation of the transmission grid." *Id.* at 8, JA 93. The ISO's responsibilities as a Control Area operator include

> scheduling generation, imports, exports, and wheeling transactions . . . ; insuring adherence to regional and

> national reliability standards; monitoring and developing transmission maintenance standards; performing operational studies and system security analyses; dispatching bulk power supplies; conducting system planning to ensure overall reliability; . . . providing emergency management; overseeing outage coordination; and performing transmission planning.

Id. (footnote omitted). The costs incurred by the ISO for its Control Area Services were allocated to Scheduling Coordinators on a "gross load" basis. The ISO defined gross load as "all Demand for Energy within the ISO Control Area. Control Area Gross Load does *not* include auxiliary Load (*i.e.* energy used in the power production process) or Load that is electrically isolated from the ISO Control Area (*i.e.* Load that is not synchronized with the ISO Control Area)." *Id.* The *Inter-Zonal Scheduling* category of services is not at issue in this case. *Market Operations* services "include the ISO's cost of market and settlement related services . . . includ[ing] the billing of, and payments for, Energy, Ancillary Services capacity, and transmission service into, within, and out of the ISO Control Area." *Id.* at 9, JA 94. The costs of the Market Operations services were allocated to Scheduling Coordinators based on "the proportion of a given [Scheduling Coordinator's] total purchase and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy . . . to the total purchases and sales of all [Scheduling Coordinators]." *Id.* at 10, JA 95. The sum of the charges for Control Area Services, Inter-Zonal Scheduling, and Market Operations charges made up the Grid Management Charge.

Shortly after the California ISO proposed the Grid Management Charge, PG&E proposed a new tariff for Control Area Agreement customers that would pass through the Grid Management Charge to those customers. PG&E claimed that the pass-through was justified, because Control Area Agreement "customers are the direct beneficiaries of these ISO services. It is from these [Control Area Agreement] customers that PG&E seeks recovery . . . . PG&E does not seek to earn a return on the pass-through, but rather seeks to recover only the full cost it incurs on behalf of these third parties." Letter from PG&E to David Boergers, Secretary, FERC (Nov. 9, 2000) at 6, JA 1206. The pass-through tariff was calculated to reflect the percentage that each Control Area Agreement customer contributed to the relevant portion of the Grid Management Charge. The customers were therefore billed for a portion of the Control Area Services charge based on the "[c]ustomer's monthly Gross Load" and the Market Operations charge was billed based on the customers "total purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy." Schedule 1, PG&E's GMC Pass-Through Tariff, JA 1210.

Several parties, including the petitioners in this case, objected to the structure of the Grid Management Charge and pass-through tariff. In May 2003, the Commission addressed objections filed by affected parties to the Initial Decision of an Administrative Law Judge ("ALJ") approving the charge and tariff. *Cal. Indep. Sys. Operator Corp.*, 103 F.E.R.C. ¶ 61,114 at 61,352 (2003) ("Opinion No. 463") (reviewing *Cal. Indep. Sys. Operator Corp.*, 99 F.E.R.C. ¶ 63,020 at 65,068 (2002) ("Initial Decision")). Among the issues addressed were: "the assessment of the Control Area Service charge based on control area gross load"; "the assessment of the charge to retail behind-the-meter load"; and "whether PG&E's [pass-through tariff] passes through the costs of a new service providing new benefits to the [Control Area Agreement] customers." *Id.* at 61,353.

The Commission upheld the decision of the ALJ that gross load allocation of the Control Area Services charge did not violate cost causation principles. Several parties had argued to the ALJ that "allocation of [Control Area Services] charges based on [gross load] violates the Commission's cost causation principles because it includes behind-the-meter loads which do not 'use' the ISO Controlled Grid." Initial Decision, 99 F.E.R.C. at 65,109 (footnote omitted). The phrase "behind-the-meter load" was defined by the ALJ to

> refer to circumstances in which retail Loads of an entity and the Generation from which that entity serves the Loads are located on the same side of the meter at the interconnection between the ISO Controlled Grid and the transmission or distribution facilities of the entity. Parties have denominated these circumstances as "wholesale behind-the-meter." It may also refer to circumstances in which a Load is served by a Generator located on the side of the retail meter between the Load and the ISO Controlled Grid or between the Load and the distribution system of a [Utility Distribution Company]. Parties have denominated these circumstances as "retail behind-the-meter."

Id. at 65,109 n.66 (citations omitted).

The ALJ rejected this argument on the ground that "both 'cost causation' and 'benefits received' are appropriate considerations in determining whether the ISO's [Control Area Services] charge is 'just and reasonable.'" *Id.* at 65,109. Where an ISO has taken over the transmission grid, "all users of the regional grid will [benefit] when that grid is operated and planned by a single regional entity"; in that circumstance, it was appropriate for "[a]ll customers using that grid [to] share in all the costs of the grid, because they all *benefit*." *Id.* (quoting *Midwest Indep. Sys. Operator, Inc.*, 98 F.E.R.C. ¶ 61,141 at 61,408, 61,412 (2002) ("Opinion No. 453-A")). Citing testimony from several witnesses, the ALJ concluded that Control Area Services are "provid[ed] on behalf of all Load within the ISO Control Area" and that "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." *Id.* at 65,110.

The Commission affirmed the Initial Decision on this issue, citing language from its decision in Opinion No. 453-A in which the "Commission established that the benefits received by loads served through non-grid facilities justified the allocation of costs to those loads." Opinion No. 463, 103 F.E.R.C. at 61,357 (citing Opinion No. 453-A, 98 F.E.R.C. at 61,412).

While, in general, the Commission agreed that gross load was an acceptable basis for allocating the Control Area Services charge, it found 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 [Control Area Services] 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 [Control Area Services] 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 [Control Area Services] costs. Customers eligible for such treatment are those with generators with a 50 percent or greater capacity factor.[44]
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> [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.

Id. The Commission agreed with the ALJ's decision that retail and wholesale generators should be treated similarly, noting that the gross load allocation "exemption applies . . . whether the behind-the-meter generation is wholesale or retail." *Id.* at 61,358.

The Commission then turned to objections that had been raised against the PG&E pass-through tariff. Objectors complained that the pass-through tariff amounted to a change in existing contracts for Control Area Agreement customers, thereby "run[ning] afoul of the Commission's longstanding policy not to abrogate existing contracts in the context of industry restructure." *Id*. at 61,360. Objectors also complained that the tariff violates the *Mobile-Sierra* doctrine, under which "a utility cannot unilaterally file a new rate . . . to supersede the agreed-upon rate" in an existing contract. *Id.* (quotation marks and emphasis omitted).

The Commission rejected these arguments, finding that "the existing [Control Area Agreements] are not being modified in any manner, so that the agreed-upon rate for PG&E's [Control Area Agreement] services is not being superseded. Rather . . . these customers of PG&E are receiving a new and different service in addition to the service they already receive under the Control Area Agreements." *Id.* In analyzing the Control Area Services component of the Grid Management Charge (and therefore the pass-through tariff) the Commission addressed the argument that the pass-through tariff does not represent "new or different service 'above and beyond' what [the Control Area Agreement customers] were provided by PG&E in its former guise as a vertically-integrated utility." The Commission found that:

> [T]here 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, [and] system planning to ensure overall reliability. Of course, PG&E formerly provided to the [Control Area Agreement] customers all the necessary services required for the safe and reliable operation of a high voltage electric transmission system. Accordingly, the

> rate schedules for each of the [Control Area Agreements] 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.
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> 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 [Control Area Agreement] customers access to the ISO controlled-grid. Consistent with its obligations as a control area operator, the ISO operates a real time Imbalance Energy market to ensure that all generation and all load within the control area are balanced on a moment-to-moment basis . . . . [T]he 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 [Control Area Agreement] customers gain access to the grid necessary to satisfy the requirements under their contracts.

Id. at 61,361-62 (footnotes omitted).

The Commission reversed the finding of the ALJ that the Market Operations charge did not represent new services. PG&E challenged the finding of the ALJ, arguing 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." *Id.* at 61,362. The Commission agreed, finding that, "[a]s with the [Control Area 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 [Control Area Agreements] is unrelated to the ISO activities that give rise to the [Market Operations] component of the [Grid Management Charge]." *Id.* The Commission also acknowledged that "[m]any [Control Area Agreement] customers argue that they should not be assessed the [Market Operations] component of the [Grid Management Charge] because they can self-provide certain services." *Id.* The Commission found that the Market Operations charge would only be assessed "for accessing the ISO-controlled grid to support transmission service" and, therefore, the Market Operations charge did not violate cost-causation principles. *Id.*

Upon requests for rehearing, the Commission reconsidered its view of the exemption to the gross load allocation that it had crafted in Opinion No. 463, finding that "this exception is not supported by record evidence." *Cal. Indep. Sys. Operator Corp.*, 106 F.E.R.C. ¶ 61,032 at 61,106, 61,111 (2004) ("Opinion 463-A"). The Commission, however, continued to "believe that certain behind the meter generators should be subject to an exception," and therefore adopted a new standard:

> In light of the nature of the [Control Area Services] 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 [control area gross load] 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 [Control Area Services] charge.

Id.

Several parties again petitioned for rehearing, and the Commission found that those petitions "have made clear that questions concerning the exemption, as well as the manner in which it would be administered, present issues of material fact that cannot be resolved based on the record before us." *Cal. Indep. Sys. Operator Corp.*, 109 F.E.R.C. ¶ 61,162 at 61,772, 61,774 (2004). The Commission therefore ordered a second evidentiary hearing on the question of the exemption. *Id.*

After conducting a second hearing, the ALJ released her findings on the exemption to the Control Area Gross Load allocation. The ALJ explained how the California ISO "models" generators:

> [I]t is necessary to keep in mind that the ISO does not actually model generating units. Instead, it adopts the power flow models, including the representations of generating units, which are developed by the investor-owned [Participating Transmission Operators]. A model is a quantitative representation of the facilities that constitute the grid, and their physical limitations. . . . The ISO has explained that while it does not model generating units *per se*, it does use the models provided to it by the [Participating Transmissions Operators] to conduct studies that examine the effects of different conditions under which the transmission system may have to operate and to determine the effects of the conditions on the transmission system.

Cal. Indep. Sys. Operator Corp., 111 F.E.R.C. ¶ 63,008 at 65,044, 65,052-53 (2005) ("Initial Decision II") (footnotes omitted).

The ALJ also recited the ISO's view that "the purpose of the [Control Area Services] charge" is not "to recover the costs of modeling generating units"; rather "the criterion of whether a generating unit was modeled . . . is an objective criterion used as a surrogate to identify load with a more limited []dependence on the ISO's control area services." *Id.* at 65,049. The ALJ also described the kinds of behind-the-meter load and generation that must be modeled:

> (1) behind-the-meter generation that may deliver excess energy to the transmission system in the wholesale market arena; (2) behind-the-meter load serviced by the behind-the-meter generation that would remain connected and continue to draw power from the transmission system in the event the behind-the-meter generation tripped or was curtailed; and (3) behind-the-meter generation that is of such size, nature, and character or connected at a critical point within the transmission system such that the performance of the transmission system with respect to transient stability, voltage collapse, local area power quality, fault current contribution or coordination of protective devices.

Id. at 65,056.

In Opinion No. 463-B, the Commission adopted many of the factual findings of the ALJ, and clarified the nature and scope of the "modeling" exemption. The Commission adopted the ALJ's definition of a model as "a quantitative representation of the facilities that constitute the grid, and their physical limitations." *Cal. Indep. Sys. Operator Corp.*, 113 F.E.R.C. ¶ 61,135 at 61,536, 61,546 (2005) ("Opinion No. 463-B") (quotation marks omitted). The Commission further cited testimony from an expert witness that a "model" as used in the behind-the-meter exemption is a "numerical representation of the physical equipment, and its limits, that comprises the electric grid, the interrelations between the equipment (that is, how the pieces are 'wired' together), and the information on the real world limitations of such equipment." *Id.*

The Commission agreed with the ALJ that the "ISO does not itself create models of generating units, but uses those provided by the Participating Transmission Owners to conduct studies concerning transmission planning and operation." *Id.* The Commission, however, "reject[ed] the contention . . . that because the ISO does not actually construct the base-case models . . . it does not 'model' generation. The important fact is that the generators were included in the models which the ISO examines and on which it bases its studies. . . . [T]he relevant factor [is] *whether* a particular Generating Unit was modeled, and not *who* modeled the Generating Unit in question." *Id.* (quotation marks omitted).

The Commission also clarified that the intent of the "modeling" exemption was to "identify[] and defin[e] the subset of behind-the-meter generators which incur no Control Area Services costs (or only *de minimis* costs)." *Id.* at 61,544. Behind-the-meter generation was defined further to describe "situations in which a Load's electrical consumption cannot be distinguished from a Generating Unit's simultaneous production of electricity, because both are measured with only one meter." *Id.* at 61,544-45 (quotation marks omitted). The Commission described the intended scope of the exemption from the gross load allocation of the Control Area Services charge to be "extremely limited":

> A hypothetical situation which we believed indicated the need for an exemption was a behind-the-meter 10 MW generator which served its own load except for two weeks a year when it was off-line for maintenance. . . . [T]he great majority of the time, such a generator and an equivalent amount of behind-the-meter load would not [be] seen by the ISO, and not receive any [Control Area Services]. . . . [As a witness explained:
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>> The ISO] admits that it knows very little about the behind-the-meter load served by on-site generation, it is hard for me to understand how such load causes the []ISO to do any work. When such loads are not served by on-site generation, that is, when they are served over the utility's transmission and distribution facilities, is when they cause the []ISO to do work, such as ensuring operating reserves; but at these times,

> the []ISO sees these loads and appropriately assesses them the [Control Area Services] charge.
>
> It is the generators serving this load unseen by the ISO – for which the ISO obviously does not provide Control Area Services – for which the Commission has been trying to craft an exemption.

Id. at 61,545 (footnote omitted).

Finally, the Commission found that the record showed that "generation which is not modeled does not incur Control Area Services costs." *Id.* at 61,547. Relying on the testimony of an ISO witness, the Commission found that

> for on-site behind-the-meter generation, the ISO has no information and must make estimates to figure gross load allocation. Thus, while there is no specific quantification in the record concerning Control Area Services costs for this behind-the-meter generation, there is evidence that the ISO does not "see" this generation . . . and "does no work" for it, *except* when it is actually using the ISO grid. . . . [T]here is indeed a small subset of generators for which the ISO incurs no Control Area Services costs whatsoever.

Id. (footnote omitted). Based on these findings, the Commission found that the "modeling" exemption was justified.

The Commission issued a final opinion denying requests for rehearing of Opinion No. 463-B. The Commission maintained that the standard that it developed for the behind-the-meter exemption – allowing generators that are not "modeled" by the ISO to avoid paying the Control Area Services charge on a gross load basis – was justified. The Commission maintained "that while the mechanics of the exemption from allocation of [Control Area Services] costs based on [gross load] has evolved in the course of this proceeding as the factual record has developed, the Commission has held firm to its view that generators that will not cause the ISO to incur expenses should have their load exempted from [Control Area Services] charges." *Cal. Indep. Sys. Operator Corp.*, 116 F.E.R.C. ¶ 61,224 at 61,913, 61,916 (2006) ("Opinion 463-C"). Reviewing challenges to the standard that it had adopted, the Commission concluded that it was justified and that no party had raised any issue requiring a rehearing. The Commission therefore denied all rehearing requests in all respects. *Id.* at 61,919.

After this decision, the Existing Customers petitioned this court for review of Opinion 463-C and prior decisions of the Commission leading up to that opinion. CoGen, however, sought FERC rehearing of Opinion No. 463-C. The Commission summarily dismissed CoGen's request for a rehearing, stating that "[t]he Commission does not allow rehearing of an order denying rehearing." *Cal. Indep. Sys. Operator Corp.*, 118 F.E.R.C. ¶ 61,061 at 61,317, 61,319 (2007). CoGen then petitioned this court for review of this final order denying a rehearing of Opinion No. 463-C, and the prior opinions.

II. ANALYSIS

A. *Standard of Review*

We review the Commission's orders "under the familiar arbitrary and capricious standard." *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004). "We abide by the Commission's factual findings if they are supported by substantial evidence, and . . . affirm the Commission's orders so long as FERC examined the relevant data and articulated a rational connection between the facts found and the choice made. When FERC's orders concern ratemaking, we are particularly deferential to the Commission's expertise." *Id.* (quotation marks, citations, and alterations omitted).

B. ***CoGen's Petition Is Untimely***

Under 16 U.S.C. § 825*l*(b):

> [A] party . . . aggrieved by an order issued by the Commission . . . may obtain a review of such order in the United States Court of Appeals . . . by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition preying that the order of the Commission be modified or set aside.

This provision establishes a jurisdictional time bar on petitions for review of FERC orders. *See City of Batavia v. FERC*, 672 F.2d 64, 72-73 (D.C. Cir. 1982). Therefore, because "[s]tatutory jurisdictional requirements . . . are not mere technicalities that can be brushed aside by a court," *Williston Basin Interstate Pipeline Co. v. FERC*, 475 F.3d 330, 336 (D.C. Cir. 2006), we must parse the record with care to determine whether CoGen's petition for review is timely.

The Commission's orders became ripe for judicial review with Opinion No. 463-C, which denied all of the parties' requests for rehearing of Opinion 463-B in their entirety. The Existing Customers sought review of Opinion No. 463-B and Opinion No. 463-C after the denial of the request for rehearing. CoGen, however, filed a request for rehearing of Opinion 463-C before the Commission, a request that was denied in a summary decision, and now seeks review of the later order.

CoGen argues that Opinion No. 463-C "did not simply deny rehearing. . . . Instead, Opinion 463-C set forth a [new] standard for exemption from the [Control Area Services] charge." Reply Br. of Cogeneration Association at 4. CoGen finds this new standard in a paragraph in Opinion No. 463-C in which the Commission defends the modeling standard for the exemption to the gross load allocation against criticism that it violates cost causation principles:

> The Commission previously noted that based on cost-causation principles, certain customers should be exempted from the allocation of [Control Area Services] costs, and upon further investigation the Commission refined that exception to better match the specifics of cost-causation in this proceeding. The [California] ISO incurs administrative costs in conducting such activities as transmission planning studies and transmission operation studies. Accordingly, we disagree with [the] assertion that there is no cause and effect relationship between modeled generation and [California] ISO's administrative expenses. Additionally, [Participating Transmission Operators] historically have been the source of the transmission and generation data required to conduct such studies and analyses. *To the extent that generators are included in [Participating Transmission Operator] studies and/or models and the ISO subsequently receives the information, the ISO will decide whether that information is relevant and useful in conducting its various studies and in modeling the transmission system. If the ISO decides that the information regarding behind-the-meter generators is relevant to its studies and system modeling, then those generators are ineligible for the exemption because they are significant for study and modeling purposes and thus ultimately relate to administrative costs incurred by the ISO.* We therefore will deny rehearing requests of [CoGen] and SMUD on this issue.

116 F.E.R.C. at 61,917 (footnote omitted) (emphasis added). However, this paragraph simply does not do the work that CoGen wants it to do. Nothing in Opinion No. 463-C changes the standard given in Opinion No. 463-B. Opinion No. 463-C simply offers further justification for why the standard is appropriate and consistent with FERC's cost-causation principles. The standard, that generators that are not "modeled" by the ISO – *i.e.*, generators on which the Participating

Transmission Operators are not required to provide data to the ISO – are exempt from the gross load allocation, remained the same. It was the same before and after Opinion No. 463-C. In the language at issue, the Commission simply reiterated its argument – which it had offered many times before – that modeling was an appropriate proxy for costs incurred. That the Commission used slightly different words to do so does not make Opinion No. 463-C a separate order requiring a request for rehearing.

In order for petitioners to preserve their rights to judicial review under 16 U.S.C. § 825*l*(b), they must file a request for rehearing of a challenged order with FERC "unless there is reasonable ground for failure so to do." *Allegheny Power v. FERC*, 437 F.3d 1215, 1220 (D.C. Cir. 2006) (quoting statute). We clarified the circumstances under which a complainant need not request rehearing:

> [W]e conclude that [the Federal Power Act] does require an application for rehearing of an order on rehearing when the later order modifies the results of the earlier one in a significant way, raising objections to the rehearing order that are substantially different from those raised against the original one.

Town of Norwood, Mass. v. FERC, 906 F.2d 772, 775 (D.C. Cir. 1990). In *Allegheny Power*, we further clarified that the Act "requires a second petition only when the *result* is different; a petitioner need not file a second petition 'when the outcome had not been changed but the Commission had supplied a new improved *rationale*.'" 437 F.3d at 1222 (quoting *Cal. Dep't of Water Res. v. FERC*, 306 F.3d 1121, 1226 (D.C. Cir. 2002)) (brackets omitted).

These cases describe the conditions under which a request for rehearing is necessary to preserve challenges on objections to a Commission order, but they also indicate when a challenge is ripe for judicial review. When a petition for rehearing is not necessary – *i.e.*, when a rehearing has been denied in its entirety with no substantive modification in the order – the case is ripe for judicial review and the clock on the jurisdictional time-bar starts ticking. *Cf. Williston Basin*, 475 F.3d at 335 (holding that, under the Natural Gas Act, court had no jurisdiction over petition filed more than 60 days after the FERC order "of which [petitioner] now seeks review" where request for rehearing was not timely filed). CoGen was required to file a petition for review within 60 days of FERC's issuance of Opinion No. 463-C. It is quite clear that Opinion No. 463-C provided an adequate basis for a petition for judicial review. Because Opinion No. 463-C was simply a denial of rehearing and did not, as the CoGen argues, create a new standard for the exemption to the gross load allocation of the Control Area Services charge, CoGen's petition for review is time barred. Accordingly, we have no jurisdiction over the challenges raised by CoGen.

C. *The Grid Management Charge and Pass-Through Tariff Are for New Services*

The Existing Customers argue that the Grid Management Charge and the pass-through tariff violate the *Mobile-Sierra* doctrine because they amount to an alteration of an existing contract. The *Mobile-Sierra* doctrine arises from two Supreme Court decisions, *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956), and *Fed. Power Comm'n v. Sierra Pacific Power Co.,* 350 U.S. 348 (1956). We have described the doctrine as follows:

> Under the well-settled and oft-invoked *Mobile-Sierra* doctrine, utility providers that negotiate fixed-rate contracts with their customers may, as part of that negotiation, voluntarily relinquish some of the rate-filing freedom to which they are otherwise entitled under Section 205 of the [Federal Power Act]. Under such contracts, utility

> providers are prohibited from filing a new rate for services currently provided (and therefore subject to) the negotiated contract rate. FERC is similarly prohibited from modifying the contract rate . . . except where the modification is both required by the public interest and upon a showing that the changes are just, reasonable, and nondiscriminatory.

East Kentucky, 489 F.3d at 1309 (quotation marks, brackets, footnotes, and citations omitted).

However, where "a new rate" is intended "to recover the costs of new benefits and services," "[t]he *Mobile-Sierra* doctrine, powerful though it may be where it applies, is not implicated." *Id.* The question that we must address, then, is whether the Control Area Services charge and Market Operations charge are for new services provided by the ISO for the benefit of the Existing Customers among others. If they cover new services, then the *Mobile-Sierra* doctrine does not apply and the Commission was justified in upholding the Grid Management Charge and pass-through tariff. In *Midwest ISO* and *East Kentucky*, we addressed very similar questions relating to the Midwest ISO, and found that the ISO provided new services to customers with preexisting contracts with formerly vertically integrated utilities. Applying those cases to the California ISO, we find that the ISO similarly provides new services. Therefore, the *Mobile-Sierra* doctrine is inapplicable.

In *Midwest ISO*, we reviewed a decision by the Commission concerning the allocation of the Midwest ISO's administrative costs. *Midwest ISO*, 373 F.3d at 1366-67. The Commission had required the "ISO Cost Adder, [which] was designed to recover [Midwest ISO] administrative costs," to be applied to all loads in the system, including "bundled" and "grandfathered load." *Id.* When the Midwest ISO was created, the participating transmission owners had obligations "to provide bundled retail service (generation and transmission) to consumers at rates frozen by state legislation, state regulatory agencies, or legal settlements," as well as "pre-existing bilateral agreements with other utilities to provide wholesale transmission service at fixed rates." *Id.* at 1365. The owners proposed that the Cost Adder be applied only to "new wholesale and unbundled retail transmission," *id.* at 1365-66, but first an ALJ and then the Commission found that in order for the Cost Adder to be "just and reasonable," it had to apply to "bundled retail loads or grandfathered loads," because "[a]ll of the Midwest ISO's Participants' transmission customers will benefit" from the new system." *Id.* at 1366-67.

We upheld the Commission's determination finding that "all transmission customers – bundled, unbundled, grandfathered, whatever – benefit from the enhanced reliability and security [Midwest]ISO brings to the transmission grid." *Id.* at 1369-70. We also found that "benefits such as an overall reduction in the costs of transmitting energy within the region and large scale regional coordination and planning of transmission would redound to all users of the transmission grid." *Id.* at 1371 (quotation marks omitted). Because all transmission customers "draw benefits from being a part of the [Midwest] ISO regional transmission system, FERC correctly determined that they should share the cost of *having* an ISO." *Id.*

In *East Kentucky*, we addressed a follow-up issue. The Cost Adder at issue in *Midwest ISO* was applied by the ISO to the participating transmission owners; the question in *East Kentucky* was whether the transmission owners could pass through that charge to customers with preexisting contracts. The Commission found that the owners could pass through the cost of administering the ISO, because "the benefits brought by the []ISO represent new services not previously provided under . . . pre-ISO grandfathered contracts." *East Kentucky*, 489 F.3d at 1307 (quotation marks omitted). Those benefits included:

> (1) independent and regional grid planning (as opposed to utility-by-utility planning), (2) enhanced reliability, (3) increased efficiency, (4) more effective management of grid congestion to accommodate greater power flows, (5) access to spot markets, and (6) price transparency to facilitate bilateral contract formation.

Id. We concluded that the Commission "reasonably rested its decision on this new services analysis and considered evidence that the costs to be collected under [the new charge] are separate and distinct from the costs collected under the grandfathered agreements." *Id.* at 1308 (quotation marks omitted).

Both *Midwest ISO* and *East Kentucky* show that regional ISOs generate significant benefits for all customers of a transmission system, including customers that had preexisting contracts with formerly vertically-integrated utilities for all services. *East Kentucky* clearly rejected the argument that transmission contracts that provided for safe, reliable transmission by a regional operator positively exclude new services provided by an ISO. ISOs produce new benefits that the vertically-integrated utilities did not; therefore, it is not enough for the Existing Customers to point to their contracts with these utilities and argue that the new system does not provide them with any benefits that they had not contracted for in prior years.

FERC made factual findings that the California ISO would generate significant new services for PG&E's existing customers. In Opinion No. 463-A, the Commission noted that the California ISO has brought about "'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.'" 106 F.E.R.C. at 61,111 (quoting witness). The Commission recited some of the benefits of the ISO:

> [B]y 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 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.

Id. at 61,112.

The Commission also noted the creation of new market opportunities, which in the long term will "result in an increased supply of competing generation to load-serving entities . . . leading to lower overall costs." *Id.* These same new market opportunities were credited by this court in *Midwest ISO* and *East Kentucky* as lending support to the justification for a new charge. The Commission further noted evidence provided by PG&E that "the costs of the [Grid Management Charge] passthrough were for the ISO's service, and not the service which PG&E has provided and continues to provide under" existing contracts. *Id.* The Commission credited the testimony of PG&E witness Mr. Bray:

> Mr. Bray specifically explained that the "ISO performs certain activities in its role of control area operator which were not performed in the pre-ISO era." He further stated that the ISO's new tasks had a direct impact on PG&E, which "performs on behalf of each and every [Control Area Agreement] customer as its ISO-certified Scheduling Coordinator a new and unique function that it did not provide to the [Control Area Agreement] customers prior to the ISO." He also distinguished the costs charged by

> PG&E for services performed under the [Control Area Agreements] from the costs that PG&E was passing through to its [Control Area Agreement] customers by means of the [pass-through tariff].

Id. (footnotes, brackets, and ellipses omitted). The Commission additionally credited the testimony of PG&E 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 [the] ISO [Grid Management Charge] are included in PG&E's transmission operation and maintenance expense accounts or the [Control Area Agreements].'" *Id.* (quoting witness) (bracket omitted).

The petitioners fail in their attempts to rebut FERC's analysis. Petitioners argue that new market opportunities are not a new benefit, but this contention is directly contrary to this court's findings in *Midwest ISO* and *East Kentucky*. Petitioners also fail to address new efficiencies that are created by the existence of a regional transmission grid. The best argument presented by the petitioners is that, under the new regime, PG&E has fewer responsibilities for "managing the Control Area" and therefore fees that it collected for that role in the past should be returned to customers. Br. for Western Area Power Admin. at 45-46. The Commission addresses this argument in two ways. First, the Commission credited PG&E's testimony that the new ISO arrangement creates additional burdens on PG&E in its role as Scheduling Coordinator. More importantly, the Commission has refuted the petitioners' zero-sum argument by noting that the new arrangement – while it may generate long-term benefits – results in "exponential[]" increases in the complexity of the system. Thus, it is not the case that there is a one-for-one relationship such that each service that is now done by the ISO means one less service provided by PG&E. The point is that, together, PG&E and the ISO perform new and better services for customers. The pass-through tariff is dollar-for-dollar based on the Grid Management Charge, which itself is the cost of starting up and operating the ISO. The customers get the benefit of the new system and pay exactly the cost of the new system.

In its first Initial Decision, the ALJ found that "PG&E has failed to carry its burden of proof" to show that the Market Operations charges were for new services "when those services are being self-provided and not procured through the ISO Markets." 99 F.E.R.C. at 65,173. The Commission overruled that finding, holding that the ISO is only "assessing charges to the responsible [Scheduling Coordinator] for accessing the ISO-controlled grid to support transmission service." Opinion No. 463, 103 F.E.R.C. at 61,362. The Commission further clarified its position in Opinion No. 463-A, stating that "the [Market Operations] charge is only assessed on a Scheduling Coordinator when it procures such services through the ISO markets. The tariff further provides that a Scheduling Coordinator's responsibility for these costs is reduced by other, self-provided ancillary services." 106 F.E.R.C. at 61,114 (footnote omitted). Thus, the Commission argues, "the parties' claim of being charged twice for the same service cannot be sustained." *Id.*

The Commission's finding on the Market Operations charge is based on substantial evidence and it is not arbitrary or capricious. The Existing Customers' complaint is premised on their view that, when they self-provide ancillary services, they should not be charged a Market Operations charge because they are not availing themselves of any Market Operations services. But, as the Commission has noted, this is a misplaced concern. The billing determinant for the Market Operations charge is "the proportion of a given [Scheduling Coordinator's] total purchase and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy . . . to the total purchases and sales of all [Scheduling Coordinators]." PG&E – in its role as a Scheduling

Coordinator – then passes on that charge to its customers, based on "total purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy" to its customers. FERC, both in the administrative record and in oral arguments to this court, has indicated that all self-provision of ancillary services will be accounted for, and that the Market Operations charge for all existing customers will be reduced accordingly. The Existing Customers have shown nothing to the contrary. The Commission's findings therefore survive scrutiny under the deferential arbitrary and capricious standard of review.

Finally, we do not address the arguments raised by the Existing Customers that provisions of their contracts with PG&E either expressly forbid PG&E from charging for "new services" or provide for specific consultive procedures before any such charges may be implemented. The contract provisions cited by petitioners do not facially support the assertions they now advance. Furthermore, petitioners have failed to show that they properly raised these precise contract claims with FERC so as to preserve them for judicial review.

Because the ISO provides new services, the Grid Management Charge and PG&E's pass-through of that charge to the Existing Customers do not violate the *Mobil-Sierra* doctrine. The Commissions factual findings on this matter relied on substantial evidence, and its decision to approve the charge and pass-through was not arbitrary or capricious.

D. *The "Modeling" Exemption to the Gross Load Allocation of the Control Area Services Charge Was Not Arbitrary*

The Commission found that a gross load allocation for the Control Area Services charge was appropriate. The Control Area Services charge "represent[s] the ISO's administrative costs of providing essential services necessary to ensure the safe, reliable operation of the transmission grid and the dispatch of bulk power supplies." Opinion No. 463, 103 F.E.R.C. at

61,356 (quotation marks and brackets omitted). The Commission found that allocation of this charge on a gross load basis did not violate cost-causation principles, because "the [Control Area Services] in question are not and could not be self-provided" and "all load is wholly dependent on the performance of [Control Area Services], without which no load serving entity could operate. These services cannot . . . be duplicated by [Scheduling Coordinators] or other parties operating in a smaller service area within the ISO's footprint." *Id.* at 61,357.

Focusing on the "behind-the-meter" exemption to the gross load allocation, Br. for Western Area Power Admin. at 55-56, petitioners argue that the Commission was correct to carve out an exemption to the gross load allocation for certain types of generation, but that the final exemption adopted by the Commission was "illogical" and arbitrary, *id.* at 58. Petitioners contend that because FERC has created an exemption for generators that do not make use of the ISO controlled grid, it cannot exempt "only *some* of [that] load." *Id.* at 57. Petitioners claim that there are other types of generation "for which [California] ISO does not have to plan and over which it is not responsible" that do not fall within the exemption. *Id.* at 60. Two examples are cited by petitioners: electricity supplied to SMUD from the Western Area Power Administration "over non-[]ISO grid facilities" and electricity that flows within a "[Metered Subsystem] bubble." *Id.* at 59. A Metered Subsystem bubble, according to petitioners, is an "area . . . served by an [existing customer] relying, in part or in whole, on transmission that is outside the control of [the] ISO and where the [existing customer] is wholly responsible for all load and generation." *Id.* at x. Petitioners complain that the Commission failed to explain "why *only* 'behind-the-meter-generation' so defined would reduce the burden on the []ISO grid." *Id.* at 59.

The arbitrary and capricious standard structures our review of the Commission's adherence to the cost-causation principle. As we stated in *Midwest ISO*, the cost-causation principle requires

> that all approved rates reflect to some degree the costs actually caused by the customer who must pay them. Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. Also not surprisingly, we have never required a ratemaking agency to allocate costs with exacting precision. It is enough, given the standard of review under the APA, that the cost allocation mechanism not be "arbitrary or capricious" in light of the burdens imposed or benefits received.

Midwest ISO, 373 F.3d at 1368-69 (quotation marks, brackets, and citations omitted). "FERC is not bound to reject any rate mechanism that tracks the cost-causation principle less than perfectly." *Sithe/Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 5 (D.C. Cir. 2002).

The Commission decision does not fail arbitrary and capricious review. On several occasions, FERC has given adequate explanations for why it arrived at the "modeling" standard for the gross load exemption. In Opinion 463-B, FERC reviewed the findings of the ALJ and drew several factual conclusions that support the behind-the-meter exemption:

> [T]he Commission hereby finds that: (1) the ISO, using models provided by the Participating Transmission Owners, conducted studies concerning transmission planning and operation during the locked-in period; (2) the generating units included in these studies were modeled by the ISO during the [relevant] period, and thus the ISO

> incurred costs recovered by the ISO's Control Area Services charge; [and] (3) there is record evidence that unmodeled behind-the-meter generation did not impose Control Area Services costs because it was not taken into account by the ISO's transmission planning and operations . . . .

113 F.E.R.C. at 61,544. In Opinion 463-C, the Commission explained succinctly that when "the ISO decides that the information regarding . . . generators is relevant to its studies and system modeling . . . they are significant for study and modeling purposes and thus ultimately relate to administrative costs incurred by the ISO." 116 F.E.R.C. at 61,917.

It is worth noting that the exemption as currently crafted does not benefit the ISO or PG&E. The administrative costs incurred by the ISO that the Control Area Services charge is meant to recoup will be the same with the exemption in its current form, with a broader exemption, or with no exemption at all. The only question is who will ultimately pay, an allocation question that pits customers against each other, but not ultimately against the ISO or PG&E. Any Control Area Services charge that is not paid by petitioners in this case will simply be paid by another customer. The current exemption is reasonable and relatively straightforward to administer, while other alternatives would be much more difficult to administer.

Petitioners complain that the exemption is not perfect, and that the costs of the ISO are not shared precisely according to the users that place the most strain on the system. That may be true, but the Commission has articulated a reasoned explanation for carving out the exemption that it did. And the exemption indisputably excludes at least some of the relevant generators, and it is convenient to administer. The Commission settled on the modeling exemption only after receiving extensive public comments and carefully considering a number of possibilities. Neither the agency's deliberative process nor its final decision fails scrutiny under the arbitrary and capricious standard of review. Indeed, it is noteworthy that petitioners have not proposed any alternatives that are clearly better.

III. CONCLUSION

For the reasons discussed above, we lack jurisdiction to address CoGen's petition for review, and we deny the Existing Customers' petition for review for want of merit.