United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued February 25, 2010 Decided July 23, 2010

No. 07-1208

SACRAMENTO MUNICIPAL UTILITY DISTRICT,
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION,
ET AL.,
INTERVENORS

Consolidated with 07-1216, 07-1217, 07-1513, 08-1298,
08-1311

On Petitions for Review of Orders
of the Federal Energy Regulatory Commission

Carolyn F. Corwin and *Harvey L. Reiter* argued the causes for petitioners San Diego Gas & Electric Company and Sacramento Municipal Utility District on CRR Issues. With them on the briefs were *James R. Dean, Jr.*, *Don Garber*, and *Lucy Holmes Plovnick*. *William L. Massey* and *Glen L. Ortman* entered appearances.

Lisa G. Dowden, *Harvey L. Reiter*, and *Deborah A. Swanstrom* argued the causes for petitioners City and County of San Francisco, California, Imperial Irrigation District, and Sacramento Municipal Utility District on Tariff Charge Issues. When them on the briefs were *Meg Meiser*, *Theresa Mueller*, *M. Denyse Zosa*, and *Lodie D. White*.

Sean M. Neal, *Michael Postar*, and *Bhaveeta K. Mody* were on the brief for intervenors Modesto Irrigation District and Transmission Agency of Northern California in support of petitioners. *Wallace L. Duncan* and *Derek A. Dyson* entered appearances.

Beth G. Pacella, Senior Attorney, and *Samuel Soopper*, Attorney, Federal Energy Regulatory Commission, argued the causes for respondent. With them on the brief was *Robert H. Solomon*, Solicitor.

Kenneth G. Jaffe argued the cause for intervenors in support of respondent. With him on the brief were *Michael E. Ward*, *Nancy J. Saracino*, *Daniel J. Shonkwiler*, *Roger E. Collanton*, *Jennifer L. Key*, *E. Kathleen Moore*, *Christopher C. O'Hara*, *Arthur Lawrence Haubenstock*, *Charles Ragan Middlekauff*, *Jeffery D. Watkiss*, and *Stuart Caplan*. *Bradley R. Miliauskas* entered an appearance.

Before: BROWN, GRIFFITH and KAVANAUGH, *Circuit Judges*.

PER CURIAM: Following the California energy crisis of 2000–01, the California Independent System Operator (California ISO or the ISO) began the process of redesigning California's electricity market. The Federal Energy Regulatory Commission (FERC or the Commission) issued a series of orders providing guidance on California ISO's proposals. Ultimately, in four orders issued between 2006 and 2008, the Commission approved the ISO's new market design, rejecting the numerous objections lodged by at least sixty-seven intervenors. Four parties—the Sacramento Municipal Utility District (Sacramento), the Imperial Irrigation District (Imperial), the City and County of San Francisco (San Francisco), and the San Diego Gas & Electric Company (San Diego)—now petition for review of these orders. Sacramento and Imperial challenge California ISO's "locational marginal pricing" rate design, arguing in particular that it is unreasonable and unlawful to charge customers for the marginal cost of transmission losses. San Francisco challenges the "local resource adequacy requirement" imposed by California ISO, claiming it deprives San Francisco of the value of a preexisting contract. Finally, San Diego and Sacramento challenge aspects of the financial mechanism California ISO devised to allow customers to hedge against congestion costs. We find no merit to these arguments and therefore deny the petitions for review.

I. Background

A. The Parties

"In 1996, the Commission ordered the national deregulation of electricity transmission services. Order No. 888 required utilities to 'unbundle' their electricity generation and transmission services and to file new 'open access' tariffs—modeled on a *pro forma* tariff included in the rulemaking—guaranteeing non-discriminatory access to their transmission facilities by competing generators." *Sacramento Mun. Util. Dist. v. FERC*, 428 F.3d 294, 295–96 (D.C. Cir. 2005) ("*Sacramento I*") (citing *Promoting Wholesale Competition Through Open Access Non-Discriminatory*

Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (Apr. 24, 1996) ("Order 888")).[1] Order 888 also encouraged public utilities "to participate in Independent System Operators ('ISOs')." *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 397 (D.C. Cir. 2004). "An ISO conducts the transmission services and ancillary services for all users of such a system, replacing the conduct of such services by the system owners . . . . FERC deems it crucial that an ISO be independent of the market participants so that decisions of policy, operation, and dispute resolution be free of the discriminatory impetus inherent in the old system." *Id.* (citing Order 888 at 31,731).

Thus, in 1996, the California legislature chartered California ISO, "a non-profit organization that took over operation (but not ownership) of many transmission facilities" in the state. *Sacramento Mun. Utility Dist. v. FERC*, 474 F.3d 797, 798 (D.C. Cir. 2007). California ISO maintains a tariff, subject to approval by the Commission, setting forth the terms, conditions, and rates under which it provides electricity service to customers. Sacramento, Imperial, San Francisco, and San Diego are all "load-serving entities," meaning they acquire electricity from California ISO for delivery to end-use consumers. The wholesale rates they pay are dictated by the ISO's tariff.

However, these four petitioners are not all alike. San Diego is a privately-owned utility that became a "participating transmission owner" in California ISO by turning over

[1] We have previously traced in detail the historical developments that led the Commission to issue Order 888. *See, e.g.*, *Transmission Agency of N. Cal. v. FERC*, 495 F.3d 663, 667 (D.C. Cir. 2007); *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1363–65 (D.C. Cir. 2004).

operational control of its transmission facilities to the ISO. *See W. Area Power Admin. v. FERC*, 525 F.3d 40, 44 (D.C. Cir. 2008). Thus, California ISO assumed the obligation to honor San Diego's preexisting transmission contracts. By contrast, Sacramento, Imperial, and San Francisco are publicly-owned "non-jurisdictional" utilities that opted not to become participating transmission owners of California ISO. (They are called "non-jurisdictional" because, as governmental entities, they are not subject to FERC's jurisdiction under §§ 205 and 206 of the Federal Power Act, *see* 16 U.S.C. § 824(f).) Accordingly, they own or co-own certain transmission facilities that are within California ISO's "balancing authority area"[2] but are not part of the ISO's grid. These entities retain "transmission ownership rights"—contractual entitlements to use such facilities.

B. The Market Redesign and Technology Upgrade Proposal

"In 2000, wholesale prices for electricity in California increased dramatically and resulted in the now-infamous California energy crisis." *Pac. Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 1317 (D.C. Cir. 2004). This prompted California ISO, at the behest of the Commission, to begin redesigning California's electricity market to avoid any repetition of the 2000–01 crisis. California ISO's "market redesign and technology upgrade" proposal followed. Over the course of six years, the Commission issued more than thirty orders providing guidance to California ISO and its market participants on the various contours of the proposed changes.

[2] A "balancing authority area"—also called a "control area"—refers to the collection of generation, transmission, and end-users within the metered boundaries of the California ISO system, with respect to which the ISO is responsible for maintaining a balance of supply and demand.

The Commission ultimately approved California ISO's revised tariff in four orders issued between 2006 and 2008.[3] Three features of this tariff are challenged here: its incorporation of marginal loss charges into locational marginal prices, its local resource adequacy requirement, and its congestion revenue rights mechanism.

1. Locational Marginal Pricing

California ISO proposed to use "locational marginal pricing" (LMP) to set wholesale electricity prices. With an LMP-based rate structure, prices are designed to reflect the least-cost of meeting an incremental megawatt-hour of demand at each location on the grid, and thus prices vary based on location and time. Each LMP consists of three components: (i) the cost of generation; (ii) the cost of congestion; and (iii) the cost of transmission losses. *See* First Market Redesign Order ¶ 50. The first component refers basically to the baseline cost of serving load[4] anywhere on the system in the absence of congestion and transmission losses. *Id.* With respect to the second component, we have explained:

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[3] *Cal. Indep. Sys. Operator Corp.*, Order Conditionally Accepting the California Independent System Operator's Electric Tariff Filing to Reflect Market Redesign and Technology Upgrade, 116 F.E.R.C. ¶ 61,274 (Sept. 21, 2006) ("First Market Redesign Order"); *Cal. Indep. Sys. Operator Corp.*, Order Granting in Part and Denying in Part Requests for Clarification and Rehearing, 119 F.E.R.C. ¶ 61,076 (Apr. 20, 2007) ("Second Market Redesign Order"); *Cal. Indep. Sys. Operator Corp.*, Order Conditionally Accepting Tariff Provisions, Subject to Modification, and Granting in Part and Denying in Part Rehearing, 120 F.E.R.C. ¶ 61,023 (July 6, 2007) ("Third Market Redesign Order"); *Cal. Indep. Sys. Operator Corp.*, Order Denying Requests for Rehearing and Clarification, 124 F.E.R.C. ¶ 61,094 (July 28, 2008) ("Fourth Market Redesign Order").

[4] "Load" refers to end-use customers of the transmission system, the primary source of "demand" for electric energy.

> LMP . . . incorporates the cost of congestion into the price of energy. Under the LMP system, [an ISO] takes into account the limits on available transmission capacity when determining the price of energy at each node in its transmission grid. This results in higher energy prices at nodes that require the use of congested transmission lines and lower prices in less congested areas. . . . LMP [therefore] . . . giv[es] market participants incentives to avoid congestion-causing transactions [and] is also more economically efficient: scarce transmission capacity is allocated to those who value it most instead of being physically rationed.

Wis. Pub. Power, Inc. v. FERC, 493 F.3d 239, 250–51 (D.C. Cir. 2007). The third component, transmission losses,

> refer[s] to the amount of electric energy lost when electricity flows across a transmission system: it is a function of the square of the amount of the current flowing on the wire and of the resistance it encounters. In general, the current on a given transmission line remains a constant, and the loss associated with a single transmission of electricity is primarily a function of the distance the electricity is transmitted. [An ISO] must deliver to the electricity customer the entire amount contracted for, regardless of the inevitable loss, so a transmission customer [*i.e.*, a load-serving entity] . . . generally compensates [the ISO] for lost energy either by providing more energy at

> the injection point than the electricity customer receives at the withdrawal point, or by providing energy in-kind to the transmitting utility.

Sithe/Independence Power Partners, L.P. v. FERC, 285 F.3d 1, 2 (D.C. Cir. 2002) (citation omitted). In other words, unless the load-serving entity self-supplies sufficient electricity to make up for the amount lost during transmission, it must compensate the ISO for the losses.

Transmission losses can be calculated on either an "average" or a "marginal" basis. If transmission losses are simply averaged system-wide and allocated to all load-serving entities *pro rata*, "cross-subsidies" result: "parties that schedule[] long-distance transmissions pa[y] too little, while those that schedule[] shorter transmissions pa[y] too much." *Wis. Pub. Power*, 493 F.3d at 252. Marginal loss pricing, by contrast, "recovers transmission losses on a transaction-by-transaction basis by . . . treat[ing] every transmission as if it were the last (marginal) transmission on the system. This pricing scheme sends more efficient signals to market participants, but because transmission losses increase with the amount of current in the system, treating every transmission as the marginal transmission produces revenue in excess of actual losses." *Id.*

California ISO proposed to incorporate the marginal cost of transmission losses into LMPs, arguing this was "necessary to assure least-cost dispatch and establish nodal prices that accurately reflect the cost of supplying the load at each node." First Market Redesign Order ¶ 66 (footnote omitted). The ISO acknowledged that revenue collection would exceed losses and therefore proposed to credit excess revenues back to load-serving entities on a *pro rata* basis by reducing the cost of each megawatt hour purchased by a proportionate amount of the excess revenues. *See id.* ¶¶ 67–68.

Finally, California ISO proposed to create several zones, called "load aggregation points." Within each zone, the ISO proposed to calculate an average zonal price based upon the weighted average of the nodal LMPs within the zone. Suppliers would continue to be paid the precise LMP at a given node, but consumers would pay the aggregated price of their zone. California ISO contended that using zonal pricing for load—for a transition period—would protect consumers in congested areas from the sudden increase in costs that otherwise would result from the switch to an LMP-based market.

The Commission approved California ISO's adoption of LMP, finding it would "promote efficient use of the transmission grid, promote the use of the lowest-cost generation, provide for transparent price signals, and enable transmission grid operators to operate the grid more reliably." First Market Redesign Order ¶ 63. The Commission accepted the ISO's proposal to "reflect marginal losses in its calculation of LMP, because doing so sends more accurate price signals and assures least-cost dispatch." *Id.* ¶ 90.

Sacramento and Imperial challenge the Commission's approval of California ISO's proposal to include marginal loss charges in LMPs. They argue the Commission's finding that marginal loss charges would "necessarily" lower costs was in conflict with the Commission's previous orders and lacked substantial evidence. Sacramento also challenges the Commission's finding that marginal loss charges would result in transmission service equivalent or superior to that offered under FERC's *pro forma* tariff. Imperial challenges the Commission's finding that marginal loss charges would lead to “just and reasonable” rates and further argues the Commission exceeded its statutory jurisdiction by authorizing the ISO to assess marginal loss charges to transactions in which Imperial uses its transmission ownership rights.

2. Resource Adequacy Requirements

“Resource adequacy is the availability of an adequate supply of generation or demand responsive resources to support safe and reliable operation of the transmission grid.” First Market Redesign Order ¶ 3 n.2. The Commission explained that “ensur[ing] that all load serving entities procure adequate generation capacity to serve their load . . . is critical to maintaining reliability and ensuring that wholesale prices remain just and reasonable. Further, . . . resource adequacy requirements . . . will lessen the likelihood of price spikes occurring during periods of high demand.” *Id.* ¶ 4. As part of its market redesign proposal, California ISO proposed to impose on load-serving entities two types of resource adequacy requirements: “system” requirements and “local” requirements. System resource adequacy requirements are set by state authorities and aim to ensure there is sufficient generation in the entire California ISO balancing authority area to serve the ISO’s aggregate load. Local resource adequacy requirements are imposed on entities that serve load in constrained areas—known as “local capacity areas” or “load pockets”—where the transmission capability is insufficient to reliably serve 100% of the load without relying on generation capacity that is physically located within that area. California ISO proposed to perform an annual technical study to calculate the minimum amount of generation capacity that must be available within each local capacity area. Then, responsibility for acquiring the necessary local resources would be allocated to the applicable load-serving entities in accordance with each entity’s share of load.

San Francisco contended it should be permitted to satisfy its local resource adequacy requirement with resources it could import from outside the load pocket it serves, pursuant to a preexisting firm transmission contract. California ISO refused, explaining that the *local* requirement could only be satisfied with resources physically situated within the load pocket. FERC sided with the ISO. San Francisco petitions for review, arguing FERC's decision arbitrarily and capriciously abrogated its contractual rights.

3. Congestion Revenue Rights

As noted above, LMP incorporates the cost of congestion into the price of energy. To provide a measure of protection for customers desiring to hedge against the price uncertainty that can result from fluctuations in congestion, California ISO proposed a system of "congestion revenue rights" (CRRs). Congestion revenue rights are

> financial instruments that entitle their holders to be paid the congestion costs associated with transmitting a given quantity of electricity between two specified points. A party planning a transmission can thus hedge its exposure to congestion costs by acquiring a corresponding [congestion revenue right]. At the time of the transmission, the party will pay [the ISO] the applicable congestion costs, but will then receive the same amount back from [the ISO] in its capacity as the holder of the [congestion revenue right].

Wis. Pub. Power, Inc., 493 F.3d at 251 (citation omitted). California ISO proposed to offer two types of congestion revenue rights: short-term (with terms of less than one year) and long-term (with ten-year terms). Both would be "obligation" rather than "option" rights. Obligation rights entitle the holder to a payment when congestion is in the direction of the congestion revenue right—that is, when the price at the withdrawal point is higher than the price at the generation point—but require the holder to make a payment to the ISO when congestion is in the opposite direction. Option rights, by contrast, entitle the holder to be paid but never require the holder to make a payment.

California ISO proposed to allocate congestion revenue rights among load-serving entities according to an annual four-tier nomination process. For the allocation of short-term congestion revenue rights in Tiers 1 and 2 in the initial year, the ISO proposed to require that "nominations for CRR allocations . . . be source verified," meaning that load-serving entities would be required to "demonstrate that, during a historical reference period, the [load-serving entity] had an entitlement to receive energy from the nominated sources to serve its demand." First Market Redesign Order ¶ 712. The ISO explained that "basing the CRR allocation on a period that has already occurred avoids the potential for the allocation process to distort incentives to contract for energy." *Id.* California ISO proposed to use April 2006 to March 2007 as the historical reference period. San Diego objected, arguing that its transmission usage during this timeframe was unusually low and that the ISO's proposal would unjustifiably cause San Diego to enter the congestion revenue right allocation process with a substantial deficit of rights on which to hedge its existing procurement decisions.

California ISO proposed to allow load-serving entities to convert the short-term rights they received in Tiers 1 and 2 into long-term rights in the long term tier (Tier LT). Initially, the ISO proposed to allow entities to convert 50% of their adjusted load metric (a calculation that measures an entity's exposure to congestion costs) into long-term rights. But in response to San Diego's objection, the Commission held that no more than 20% of an entity's adjusted load metric may be nominated for long-term rights—although the percentage increases 10% annually in subsequent years until it reaches 50%.

In Tier 3 (actually the fourth tier), California ISO proposed to allow any load-serving entity to request any congestion revenue right. If demand exceeds the rights available, then every entity receives a *pro rata* share of the remaining rights. Finally, the ISO proposed to auction off any congestion revenue rights that remain after the four-tier process. Of course, at any stage in the process, load-serving entities are free to buy or sell congestion revenue rights through bilateral transactions with other market participants. Every year after the initial year, the same tiered nomination process is repeated, except allocations no longer are source verified. Instead, load-serving entities that previously have received short-term congestion revenue rights either can renew them or convert them to long-term rights. Third Market Redesign Order ¶ 164.

San Diego and Sacramento petition for review of the Commission's approval of California ISO's congestion revenue right proposal. San Diego argues FERC did not go far enough in ordering a remedy suited to San Diego's unique circumstances. Sacramento argues FERC acted arbitrarily and capriciously in determining that the ISO did not need to offer option rights in addition to obligation rights.

We consolidated these petitions for review into the instant action.

II. Discussion

"We review FERC's orders under the arbitrary and capricious standard and uphold FERC's factual findings if supported by substantial evidence." *Am. Gas Ass'n v. FERC*, 593 F.3d 14, 19 (D.C. Cir. 2010); *see* 5 U.S.C. § 706(2) (2006). "We affirm the Commission's orders so long as FERC examine[d] the relevant data and articulate[d] a . . . rational connection between the facts found and the choice made. In matters of ratemaking, our review is highly deferential, as [i]ssues of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission." *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1347 (D.C. Cir. 2009) (internal quotation marks and citations omitted).

We will first address Sacramento and Imperial's challenges to California ISO's proposal to incorporate marginal loss charges into LMPs. Second, we will consider San Francisco's argument regarding the effect of the ISO's local resource adequacy requirement on its contractual rights. And finally, we will address Sacramento and San Diego's objections to the ISO's congestion revenue rights proposal.

A.

The Commission approved California ISO's proposal to incorporate marginal loss charges as part of the locational marginal prices the ISO will charge transmission customers. Sacramento and Imperial claim the Commission acted arbitrarily and capriciously in doing so. Some of the arguments in support of that claim are advanced jointly by both Sacramento and Imperial; other arguments are advanced only by one party or the other.

1.

Both Sacramento and Imperial challenge FERC's conclusion that marginal loss pricing would "necessarily reduce" the total cost of meeting electricity demand within the California ISO system. *See* Second Market Redesign Order ¶ 41. They contend, first, that FERC's conclusion constituted an unexplained departure from a guidance order issued by the Commission in 2004; and second, that FERC's conclusion lacked substantial evidence to support it. Both arguments lack merit.

First, FERC's conclusion about the benefits of marginal loss pricing did not conflict with or depart from its 2004 guidance order.

In that 2004 order, FERC said it would "accept the CAISO's proposal to use marginal losses in its calculation of LMPs because this approach helps to assure a least-cost dispatch." *Cal. Indep. Sys. Operator Corp.*, Order on Further Development of the California ISO's Market Redesign and Establishing Hearing Procedures, 107 F.E.R.C. ¶ 61,274, at 62,269 (2004). FERC also stated: "While we believe a marginal loss approach provides for the most efficient dispatch, we would be concerned if this application were to substantially raise implementation costs of the CAISO's market redesign. We note that, if in the process of further developing the marginal loss proposal and tariff language the CAISO and market participants determine that use of average losses at inception would be more easily administered and less costly, then the CAISO may file to use average losses when it makes its tariff filing." *Id.* at 62,270. In other words, the Commission in 2004 generally approved of the use of marginal loss charges, but it left California ISO with flexibility to decide how quickly to implement those charges.

Sacramento and Imperial focus on the Commission's statement permitting flexibility in the implementation of marginal loss charges. They claim that this statement actually undermines FERC’s subsequent determination that marginal loss charges would “necessarily” lower the cost of meeting electricity demand. That is incorrect. As the Commission explicitly stated in its 2004 order, it was concerned about the possible “*implementation*” costs of moving to marginal loss pricing, which might justify the use of a different scheme “*at inception*.” *Id.* (emphasis added). The 2004 guidance order did not indicate any doubts as to whether the adoption of marginal loss charges would reduce costs in the long run. On the contrary, FERC’s 2004 statements were entirely consistent with its subsequent findings about the efficiency gains associated with marginal loss pricing.

Sacramento and Imperial also claim the 2004 guidance order required California ISO to consult with its stakeholders about the costs of using marginal loss charges. It did not. As FERC explained in response to Sacramento and Imperial’s protest, the 2004 order did not say anything about consultation; it only “required an explanation from the CAISO to the extent that it and its stakeholders determined that implementing marginal losses would be substantially more costly than implementing average losses.” Second Market Redesign Order ¶ 46. The Commission concluded that because California ISO never determined “that using marginal losses would raise the implementation cost of” its market redesign proposal, California ISO was not required to consult with its stakeholders about alternatives to marginal loss pricing, and thus it had “acted in accordance with the June 2004 Order.” *Id.* We must defer to the Commission’s reasonable interpretations of its own orders to the extent there is ambiguity, and this interpretation of the 2004 order was eminently reasonable. *See Wis. Pub. Power Inc.*, 493 F.3d 239.

Second, FERC's conclusion about the benefits of marginal loss pricing was supported by substantial evidence—that is, "such relevant evidence as a reasonable mind might accept as adequate to support the conclusion." *Consol. Oil & Gas, Inc. v. FERC*, 806 F.2d 275, 279 (D.C. Cir. 1986) (internal quotation marks omitted).

The record before the Commission contained evidence adequate to support the Commission's finding of an efficiency gain from using marginal loss charges. In particular, that finding was supported by the testimony of Lorenzo Kristov, California ISO's "Principal Market Architect," and that of Farrokh Rahimi, California ISO's "Principal Market Engineer." *See* J.A. 340 (Prepared Direct Testimony of Lorenzo Kristov) ("By paying supply resources their nodal LMPs with marginal losses included the CAISO sends them price signals that correspond to operating levels consistent with the optimal Dispatch of resources to meet Demand."); J.A. 886-87 (Prepared Direct Testimony of Farrokh Rahimi) (explaining calculation of marginal loss component of LMP). The Commission cited both experts' testimony in support of its conclusion regarding the benefits of marginal loss charges. *See* Second Market Redesign Order ¶ 41 n.65.

Sacramento and Imperial argue that the Commission ignored contrary testimony from Ziad Alaywan, an energy industry consultant with experience working for California ISO. Alaywan questioned the reasonableness of the marginal loss charge proposal in two different ways: First, he predicted that California ISO's decisions to charge zonal prices rather than nodal prices and to refund excess marginal loss revenue to customers would reduce the efficiency gains anticipated from the move to marginal loss pricing. Second, he stated that the volatility of marginal loss charges would create planning problems for long-term firm transmission customers. *See* J.A. 1206–13 (Prepared Answering Testimony of Ziad Alaywan P.E.). In other words, Alaywan argued that using marginal losses would result in fewer benefits and more costs than expected.

FERC addressed Alaywan's arguments. In response to the suggestion that zonal aggregation and refunding of excess revenues would reduce the benefits of using marginal loss charges, the Commission explained that (i) customers would face the same marginal-loss-charge differential across suppliers, and would thus have the same incentives to select the lowest-cost supplier, regardless of whether the customers paid a nodal or zonal price; and (ii) each customer would receive the same per-megawatt-hour rebate regardless of whether that customer chose a high-cost or low-cost supplier, so the rebates would not affect the customer's incentives to choose the lowest-cost supplier. *See* Second Market Redesign Order ¶ 37 & nn.60–61. And in response to the contention that the volatility of marginal loss charges would create planning problems for long-term customers, the Commission found that "the overall benefits of" marginal loss charges "outweigh the perceived difficulties in hedging" those charges. *Id.* ¶ 42. Thus, the Commission reasonably responded to the issues raised by Alaywan's testimony.

In any event, even if Alaywan's testimony arguably could have supported a different conclusion on the costs and benefits of the marginal loss proposal, that would not mean FERC's conclusion lacked substantial evidence. We must "defer[] to the Commission's resolution of factual disputes between expert witnesses." *Elec. Consumers Res. Council v. FERC*, 407 F.3d 1232, 1236 (D.C. Cir. 2005); *see also Ariz. Corp. Comm'n v. FERC*, 397 F.3d 952, 954-55 (D.C. Cir. 2005) (FERC's orders do not lack substantial evidence "simply because petitioners offered some contradictory evidence") (internal quotation marks omitted).

Finally, Sacramento and Imperial maintain that the Commission's conclusion about the benefits of using marginal loss charges lacked substantial evidence because it was based "solely on theoretical postulates." Pet'rs' Br. on Tariff Charge Issues at 24 (quoting *Elec. Consumers Res. Council v. FERC*, 747 F.2d 1511, 1518 (D.C. Cir. 1984)). In advancing that argument, Sacramento and Imperial misunderstand our precedent. As we have recognized, this Court's rationale for vacating the FERC order at issue in our 1984 decision in *Electric Consumers* was not that the Commission had relied on economic theory, but that it had "distorted the economic theory it claimed to apply." *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 688 (D.C. Cir. 2000). Neither *Electric Consumers* nor any other case law prevents the Commission from making findings based on "generic factual predictions" derived from economic research and theory. *Id.* (quotation omitted). Under our precedent, therefore, it was perfectly legitimate for the Commission to base its findings about the benefits of marginal loss charges on basic economic theory, given that it explained and applied the relevant economic principles in a reasonable manner.

2.

Sacramento argues that California ISO's proposal to use marginal loss charges was inconsistent with the requirement, embodied in FERC Orders 888 and 890, that tariff provisions be consistent with or superior to the terms of the Commission's *pro forma* tariff.

FERC established the *pro forma* tariff in 1996, setting it out in Appendix D to Order 888. *See* Order 888 at 21,706–24. The current version of the *pro forma* tariff, as revised most recently in 2007, appears in Appendix C to Order 890. *See Preventing Undue Discrimination and Preference in Transmission Service*, 72 Fed. Reg. 12,266, 12,503–31 (Feb. 16, 2007) ("Order 890"). The *pro forma* tariff contains "minimum terms and conditions of non-discriminatory service." *Id.* at 12,269 ¶ 14. Transmission providers may adopt tariff provisions that deviate from those of the *pro forma* tariff, but any deviations must be "consistent with or superior to" the terms of the *pro forma* tariff. *Id.* at 12,288–89 ¶¶ 143, 157; *see also* Order 888, 61 Fed. Reg. at 21,618–19; *Sacramento I*, 428 F.3d at 296.

Sacramento maintains that the adoption of marginal loss charges rendered California ISO's proposed tariff inferior to the *pro forma* tariff in two distinct ways: (i) by making it harder for customers to hedge against price uncertainty, and (ii) by making it harder for customers to self-supply energy losses associated with their transactions. FERC addressed both of Sacramento's arguments, and its conclusion that California ISO's proposed tariff was consistent with the *pro forma* tariff was both reasonable and reasonably explained.

First, Sacramento argues that because marginal loss charges are volatile and cannot be hedged, customers under the California ISO tariff are less able to avoid price uncertainty than are customers under the *pro forma* tariff. This is because the *pro forma* tariff enables customers to avoid price volatility by obtaining long-term physical firm transmission rights with fixed rates. Sacramento further points out that in 1999, FERC determined that a tariff that included variable *congestion* charges would be inferior to the *pro forma* tariff unless it offered customers an instrument for hedging against those congestion charges. *See Cal. Indep. Sys. Operator Corp.*, Order Conditionally Accepting Proposed Tariff Changes, 87 F.E.R.C. ¶ 61,143, at 61,570 (1999); *see also Sacramento I*, 428 F.3d at 297.

As the parties agree, at the present time no one has been able to develop a mechanism for customers to hedge against variable marginal loss charges. *See* Second Market Redesign Order ¶ 42 ("hedging mechanisms for marginal losses are in the experimental stage"); J.A. 1165 (Sacramento Protest) ("Marginal losses are inherently unhedgable."). Therefore, Sacramento insists, FERC should have ruled that the inclusion of marginal loss charges without a marginal loss hedge made California ISO's proposed tariff inferior to the *pro forma* tariff.

In the proceedings below, FERC sufficiently addressed Sacramento's argument that the lack of a marginal loss hedging mechanism made California ISO's proposed tariff inferior to the *pro forma* tariff. The Commission explained at length that a system of locational marginal pricing would benefit load-serving entities like Sacramento by providing more efficient dispatch and more accurate signals regarding the need for investment in particular generation or transmission facilities. *See, e.g.*, Third Market Redesign Order ¶ 246. However, because no one has been able to develop a marginal loss hedge, exposing customers to variable, unhedgeable marginal loss charges is currently a necessary cost of the shift to locational marginal pricing. FERC concluded that the benefits of locational marginal pricing outweighed that cost, so that a tariff with locational marginal pricing—even one lacking a marginal loss hedge—would be superior to a tariff without that pricing mechanism. *See id.* ("the 'total package' of [locational marginal pricing] and [congestion revenue rights] is superior to a pure physical rights regime"); Fourth Market Redesign Order ¶ 100 ("the benefits of marginal losses outweigh the perceived difficulties in hedging them"). That determination involved a "policy judgment[] . . . at the core" of FERC's "regulatory mission," and we therefore afford it substantial deference. *Alcoa*, 564 F.3d at 1347 (quotation omitted).

Relatedly, Sacramento argues that when FERC denied its request for a "transition mechanism" to refund marginal loss charges to customers until a marginal loss hedge could be developed, the Commission made an unexplained departure from one of its own prior decisions. San Francisco et al. Reply Br. on Tariff Charge Issues at 10; *see Midwest Indep. Transmission Sys. Operator, Inc.*, Order Conditionally Accepting Tariff Sheets To Start Energy Markets and Establishing Settlement Judge Procedures, 108 F.E.R.C. ¶ 61,163 (2004) ("*Midwest ISO*"). Sacramento is wrong: FERC did not depart from *Midwest ISO*. In that case, the Commission conditionally approved the adoption of marginal loss charges but mandated a "transitional safeguard . . . suspending marginal loss charges above average or historical loss charges for a period of five years" in order to give customers "time to adjust" to marginal loss pricing. *Id.* at 61,925-26 ¶ ¶ 66, 73–74. In this case, however, Sacramento never requested a "transitional" refund mechanism of the type FERC required in *Midwest ISO*. On the contrary, Sacramento cited *Midwest ISO* only in connection with its argument that marginal loss pricing would *never* be acceptable without a hedging mechanism—a mechanism that Sacramento itself suggested would be impossible to develop. Consequently, the Commission's decision not to accept Sacramento's suggestion to indefinitely postpone implementation of marginal loss pricing was not a "departure" from *Midwest ISO*.

Second, Sacramento argues that because marginal loss charges cannot be "self-supplied" without overestimating the amount of the charges, customers under the California ISO tariff are less able to self-supply the energy losses associated with their transmission service than are customers under the *pro forma* tariff.

As explained above, energy losses occur whenever a transmission provider delivers electricity to a transmission customer. The customer must account for those losses. Under the *pro forma* tariff, the customer has two basic options for doing so: It can either pay the transmission provider the value of the lost energy, or it can self-supply the losses by scheduling or providing additional energy to cover the energy that will be lost during transmission. *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*, 62 Fed. Reg. 12,274, 12,310 (Mar. 4, 1997) ("Order 888-A"). A customer that chooses to self-supply losses can either generate the lost energy itself or purchase it from a third party. *Id.*

The *pro forma* tariff facilitates self-supply by requiring a transmission provider to tell its customers "what the energy and capacity loss factors would be for any transmission service it may provide so that potential customers will know the amount of losses to replace." Order 888, 61 Fed. Reg. at 21,583. Under the *pro forma* tariff, then, a customer taking service under a long-term contract can calculate the losses for which it will be responsible over the term of the contract and provide for those losses in advance, thereby avoiding risk and uncertainty. Under California ISO's proposed tariff, however, marginal loss charges are variable and cannot be forecast with certainty. Therefore, Sacramento maintains, customers wanting to self-supply the energy losses associated with their future transmission service will not be able to do so as effectively under the California ISO tariff as they could under the *pro forma* tariff. *See* J.A. 1164 (Sacramento Protest).

In the proceedings below, FERC acknowledged that under the California ISO tariff, customers would not be able to predict marginal loss charges with certainty. But the Commission determined that this did not render California ISO's tariff inferior to the *pro forma* tariff because customers would still be able to self-supply their transmission losses by "conservatively estimating" the amount of future loss charges. Second Market Redesign Order ¶ 47. FERC thus concluded that the "consistent with or superior to" standard of Orders 888 and 890 is satisfied by a regime where self-supply requires conservative estimation.

That conclusion is entitled to substantial deference, both as an interpretation of the parameters set by FERC's own orders, *see Wis. Pub. Power*, 493 F.3d at 266, and as a judgment involving regulatory policy at the core of FERC's mission, *see Alcoa*, 564 F.3d at 1347. The determination of how one tariff compares to another is a technical inquiry properly confided to FERC's judgment. While it might have been preferable for the Commission to provide a fuller explanation of why the ability to "conservatively estimat[e]" losses is equivalent or superior to the ability to precisely predict losses, the Commission's failure to discuss that issue at greater length is not fatal to its order. The Commission grappled with Sacramento's objection and provided a rational justification for rejecting it, and we cannot say the Commission's conclusion was unreasonable.

3.

Imperial contends that the system of locational marginal pricing proposed by California ISO was not just and reasonable as required by § 205 of the Federal Power Act. In support of that contention, Imperial makes two distinct arguments. First, Imperial asserts that California ISO's tariff will not realize the theoretical benefits of including marginal loss charges in LMP because customers will pay zonal aggregate prices rather than nodal prices. Second, Imperial argues that the marginal loss charges in California ISO's tariff, and the mechanism for refunding excess revenues from those charges back to customers, are not consistent with cost causation principles. We find that neither of these arguments has merit.

First, as we have already explained, FERC reasonably responded to the argument that zonal aggregate pricing would prevent California ISO from realizing the benefits of locational marginal pricing.

The Commission determined that having customers "pay zonal, and not nodal, prices" would neither "preclude least-cost dispatch" nor prevent "the economic efficiency benefits of marginal losses" from materializing. Second Market Redesign Order ¶ 37. The key point, FERC emphasized, was that "all *suppliers* will receive nodal prices that reflect the cost of marginal losses." *Id.* (emphasis added). The Commission explained that this would ensure least-cost dispatch for the following reason: "The delivered cost of a source depends on its cost at the source's location, plus costs for losses and congestion. Since all suppliers will receive nodal prices . . . the difference in marginal loss charges will be the same whether the load pays a nodal or a zonal price." *Id.* In other words, FERC concluded that regardless of whether California ISO employed a zonal or nodal pricing structure, transmission customers would have the same incentive to select the lowest-cost supplier.

The Commission had substantial evidence on which to base that conclusion, as its Principal Market Architect testified that "there is general agreement among experts and those who operate markets based on LMP that the most important element in achieving the operational benefits of LMP is to settle supply resources at nodal prices, and that it is much less important to settle Demand at nodal prices." J.A. 343 (Prepared Direct Testimony of Lorenzo Kristov).

Imperial has not offered any meaningful response to the Commission's reasoning on this point and has failed to show that the Commission's conclusion was arbitrary or capricious.

Second, FERC reasonably concluded that California ISO's treatment of marginal loss charges was consistent with cost causation principles.

California ISO proposed to credit excess revenues from marginal loss charges back to transmission customers on a *pro rata* basis by using those revenues to uniformly reduce the cost of each megawatt-hour purchased on the system. *See* First Market Redesign Order ¶¶ 67–68. Imperial complains that this refund mechanism "lacks any rational nexus to specific ratepayers which actually paid more money than necessary to replace energy lost when transmission service was provided to them." Pet'rs' Br. on Tariff Charge Issues at 37.

FERC fully addressed that cost-causation argument below. The Commission acknowledged that because transmission losses increase exponentially with overall system usage, charging each customer for marginal losses rather than average losses will result in over-collection "roughly by a factor of two." First Market Redesign Order ¶ 66. But the Commission explained that treating each transmission customer as the marginal customer is consistent with cost-causation principles because "the cost incurred to serve any customer (while serving all other customers) is the marginal cost of delivering electricity to the customer." Second Market Redesign Order ¶ 44. In other words, it is not "possible to determine a cost below marginal cost that any individual [customer] caused as a result of that customer's use of electricity." *Id.* Thus, it is "just and reasonable for a customer to pay a price for electricity that reflects the marginal cost of producing and delivering it to the customer." *Id.* The Commission then reasoned logically that "since the price customers are paying (based on marginal losses) is the correct marginal cost for the energy they are purchasing, customers are not entitled to receive any particular amounts through disbursement of the over-collections." First Market Redesign Order ¶ 94.

The Commission's explanation was reasonable. Although treating every customer as the marginal customer results in over-collection *in the aggregate*, that treatment is reasonable for each customer. No customer is less deserving than another of being treated as the marginal customer; therefore, no customer is entitled to demand a refund greater than its *pro rata* share of the excess revenues collected.

Beside those two arguments, Imperial also claims that locational marginal pricing with marginal loss charges will not send accurate price signals to transmission customers because a customer "will not know the amount of those [marginal loss] charges at the time service is requested." Pet'rs' Br. on Tariff Charge Issues at 35. Because neither

Imperial nor any other party raised that argument before the Commission, it has been forfeited. *See* 16 U.S.C. § 825*l*(b) ("No objection to [an] order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing unless there is reasonable ground for failure so to do."). In any event, we have previously accepted the precise rationale that FERC relied on in this case. *See Wis. Pub. Power*, 493 F.3d at 252 ("Marginal loss pricing recovers transmission losses on a transaction-by-transaction basis by incorporating them into the LMP. . . . This pricing scheme sends more efficient signals to market participants . . . .").

4.

California ISO's proposed tariff recognized that "[t]ransmission [o]wnership [r]ights represent transmission capacity on facilities that are located within the [California ISO balancing authority area] that are either wholly or partially owned by an entity that is not a [p]articipating [transmission owner]." Tariff § 17. For example, Imperial and San Diego (along with a third utility) jointly own the Southwest Power Link transmission line, which is located within the ISO's balancing authority area. Because San Diego is a participating transmission owner of the ISO but Imperial is not, Imperial has transmission ownership rights entitling it to a share of the line's transmission capacity.

California ISO proposed to treat transactions involving transmission ownership rights as follows: If a preexisting transmission ownership rights agreement specified a methodology for calculating transmission losses, the ISO would honor it. *See* First Market Redesign Order ¶ 1003. Otherwise, the transaction would be treated like any other on the ISO's grid, *i.e.*, the load-serving entity would be required either to self-supply sufficient electricity to cover transmission losses, or it would be charged the marginal cost of losses and would receive a *pro rata* refund of the revenue over-collection. *See id.* ¶ 976 & n.418. Imperial objected on the ground that holders of transmission ownership rights "are not using [California ISO's] transmission system to deliver energy purchased from the [ISO]. . . . [Rather, they] are using their own transmission capacity." Second Market Redesign Order ¶ 452. Therefore, Imperial argued, "loss provisions . . . should be matters negotiated between [California ISO] and a [transmission ownership rights] holder." *Id.* The Commission rejected Imperial's objection, explaining that California ISO could assess marginal loss charges to transactions involving transmission ownership rights when those transactions cause losses on the ISO's grid. *See id.* ¶ 458.

Imperial petitions for review, arguing the Commission's decision exceeded its statutory jurisdiction. "FERC's interpretation of its own statutory jurisdiction is entitled to *Chevron* deference." *Detroit Edison Co. v. FERC*, 334 F.3d 48, 53 (D.C. Cir. 2003). Governmental entities such as Imperial "are exempt from the [Federal Power Act] and therefore exempt from FERC's jurisdiction when they provide transmission services." *Transmission Agency of N. Cal.*, 495 F.3d at 667 n.4; *see* 16 U.S.C. § 824(f). According to Imperial, by approving California ISO's assessment of marginal loss charges to transactions involving Imperial's use of transmission ownership rights, FERC unlawfully "dictat[ed] rates, terms or conditions of service . . . to a non-jurisdictional governmental entity's use of its own transmission facilities" and effectively "compel[led] such entity to transfer . . . control over its transmission facilities to [California ISO]." Pet'rs' Br. on Tariff Charge Issues at 41–42.

This is a gross mischaracterization of what the Commission authorized. FERC made clear in its order that marginal loss charges could be applied only to "transactions that . . . involve injections and withdrawals from the [California ISO] grid" and could not be assessed "where the [transmission ownership rights] holder has no point of interface with the [ISO]." Second Market Redesign Order ¶ 458 & n.432. And at oral argument, counsel for the Commission insisted the ISO could never charge for losses occurring on "[Imperial's] own transmission ownership rights part of the system." *See* Tr. of Oral Argument at 35:1–3; *see also id.* at 35:21–23 ("There will be no marginal loss charges under these orders for transmission over the transmission ownership right."). Asked whether marginal loss charges could be assessed to any portion of a transaction that occurs "off the [California ISO] grid," FERC's counsel responded unambiguously in the negative. *Id.* at 36:15–18. Given these limitations, we are satisfied the Commission did not exceed its jurisdiction. Far from compelling Imperial to become a participating transmission owner of California ISO, FERC merely permitted the ISO to charge Imperial for the costs incurred by the ISO when Imperial conducts transactions that cause transmission losses on the ISO's grid. The Commission's proper exercise of its power to regulate California ISO's rates was not transformed into a violation of its statutory jurisdiction by dint of its incidental effect on Imperial. *See Transmission Agency of N. Cal.*, 495 F.3d at 671–72 (holding FERC did not exceed its jurisdiction in passing judgment on a non-jurisdictional entity's revenue requirement because such review was necessary in order for FERC to determine whether the ISO's rates were "just and reasonable").

An analogous issue was presented in *Mich. Pub. Power Agency v. FERC*, 405 F.3d 8 (D.C. Cir. 2005). There, following FERC's assessment of annual charges on the Midwest Independent System Operator (Midwest ISO), the Commission approved Midwest ISO's request to pass through a proportionate share of those charges to two non-jurisdictional governmental agencies. *Id.* at 11–12. The agencies petitioned for review, claiming FERC exceeded its jurisdiction in authorizing the "pass-through of annual charges for the portion of the transmission that they take pursuant to their ownership interests." *Id.* at 12. We acknowledged that the Commission could "not . . . assess[] annual charges *directly*" on the agencies but held there was no "jurisdictional bar . . . to *passing through* a share of those charges to the [governmental] [a]gencies." *Id.* at 13 (emphasis added). We reasoned that because "the [governmental] [a]gencies use [Midwest ISO's] transmission system when they take transmission pursuant to their ownership interests," and because "the Commission regulates that system and incurs costs for such regulation that it seeks to recoup through its annual charges," the Commission was "empowered to . . . permit a public utility to pass through a proportionate share of its annual charge to [the governmental agencies]." *Id.*

Similarly, here, Imperial relies on California ISO's transmission system even when it "take[s] transmission pursuant to [its] ownership interests." *Id.*; *see* Second Market Redesign Order ¶ 458 (noting that "[e]ven though . . . the [transmission ownership rights] facilities are not a part of [California ISO], they are integrally connected to the [ISO's] grid"); *id.* ¶ 484 (noting that "[transmission ownership rights] facilities . . . are interconnected with the [ISO's] grid and, therefore, influence power flows on the grid"). For instance, the Commission and California ISO both assert that, because Imperial's transmission ownership rights pertain to facilities located within the ISO's balancing authority area, the ISO is charged with responsibility for supplying any electricity shortfall if Imperial does not self-supply sufficient electricity to cover all transmission losses. Even at oral argument, counsel for Imperial failed to dispute this proposition. *See* Tr. of Oral Argument at 28:19–25. Rather, counsel merely declared that Imperial always "self-suppl[ies] energy to make up for losses." *Id.* at 28:25; *see also id.* at 30:1–3, 30:14–17. That, however, is a non-sequitur. Because Imperial causes transmission losses on California ISO's transmission system when Imperial conducts transactions involving an injection or withdrawal from the ISO's grid, *see* Second Market Redesign Order ¶ 458 & n.432, the ISO understandably desired to charge Imperial for the cost of those losses *if* Imperial happens *not* to self-supply sufficiently. The Commission reasonably concluded that it had jurisdiction, not to "authoriz[e] [California ISO] to charge Imperial for the use of its own facilities," but to "allow[] the [ISO] to charge Imperial for services the [ISO] is providing under [its] [t]ariff, and for use of [California ISO]-controlled facilities." *Id.* ¶ 485.

Imperial argues that even if the Commission did not exceed its statutory jurisdiction, it acted arbitrarily and capriciously in finding it "just and reasonable" to assess marginal loss charges to transactions involving non-jurisdictional entities' use of transmission ownership rights. We disagree. As explained above, the Commission reasonably found that charging for marginal losses sends more accurate price signals, promotes efficient dispatch, and is consistent with cost causation principles. Imperial offered no persuasive reason why these same benefits would not also flow from assessing marginal loss charges to transactions involving transmission ownership rights. *See* Second Market Redesign Order ¶ 484. Nor did the Commission, as Imperial argues, "erroneously conflate[] the burden of proof" by obligating Imperial to prove that the ISO's proposal was *not* "just and reasonable." Pet'rs' Br. on Tariff Charge Issues at 55. Rather, FERC properly placed the "initial burden of showing that the tariff proposal is just and reasonable" on California ISO. Second Market Redesign Order ¶ 14; *see also id.* ¶ 484. Then, after finding that the ISO had established that it was "just and reasonable" to assess marginal loss charges to transactions that cause losses on the ISO's grid, *see* First Market Redesign Order ¶ 987, the Commission simply found that Imperial had failed to controvert that conclusion, *see* Second Market Redesign Order ¶ 458. Furthermore, we note that the Commission ordered California ISO to "honor specified loss percentages in [transmission ownership rights] agreements, and only assess marginal losses to [transactions involving transmission ownership rights] in the absence of such explicit loss percentages." *Id.* ¶ 484. FERC sensibly concluded that this would provide "a reasonable accommodation" between, on the one hand, honoring the contractual rights of transmission ownership rights holders, and on the other hand, preventing undue discrimination among grid users and achieving the efficiency benefits of marginal loss pricing. *See* First Market Redesign Order ¶ 1003; Second Market Redesign Order ¶ 475. In sum, Imperial has failed to show that the Commission exceeded its jurisdiction or acted arbitrarily or capriciously in approving California ISO's assessment of marginal loss charges in these limited circumstances.

5.

In a final attack on FERC's approval of marginal loss pricing, Imperial argues that the imposition of marginal loss charges—particularly on holders of transmission ownership rights—will deter utilities from making investments in transmission infrastructure. The Commission has recognized that its Congressionally-defined regulatory mission includes stimulating transmission investment. *See, e.g.*, Order 890 ¶ 79 (noting that the Energy Policy Act of 2005 "placed special emphasis on the development of transmission infrastructure") (citing 16 U.S.C. § 824s). However, contrary to Imperial's claim that FERC abdicated this responsibility, the Commission carefully analyzed whether California ISO's proposed market reforms would incentivize smart, efficient infrastructure investment. For instance, the Commission explained that incorporating marginal loss charges into LMPs "will create financial incentives to dispatch the lowest cost energy," and "[i]n the long-term, by making energy and congestion prices more transparent, . . . will help encourage transmission and generation investment at appropriate locations." First Market Redesign Order ¶ 10. This finding was not arbitrary or capricious because, as explained at length above, the Commission reasonably found, based on substantial evidence, that charging for marginal losses would send more accurate price signals to market participants. It logically follows that marginal loss pricing "will signal more accurately the location where new transmission and/or generation needs to be built and where investments in demand response should be made." Third Market Redesign Order ¶ 254. Thus, the Commission had a sound basis for rejecting "Imperial's claims that treatment of [transmission ownership rights] under [California ISO's proposal] will create a disincentive for new transmission investment," and concluding that "the assessment of marginal losses [to transactions involving transmission ownership rights] will provide a more accurate cost allocation mechanism than the application of average losses, and can help entities better predict cost exposure when planning transmission expansion." Second Market Redesign Order ¶ 475. We see no merit to Imperial's contention that the Commission failed to give adequate consideration to its arguments, or acted arbitrarily or capriciously in rejecting them.

B.

We next turn to San Francisco's challenge to the resource adequacy requirement. San Francisco provides electricity to consumers situated within a load pocket, which means the capacity to transport power into the city is so limited that imported generation alone cannot reliably satisfy customer demand for electricity. First Market Redesign Order ¶ 1156 n.507. To guarantee reliability, California ISO proposed a requirement that would call upon San Francisco to ensure that a certain amount of generation capacity is located within the load pocket. *Id.* ¶ 1156. San Francisco contends that its contracts to import electricity are as good as having locally generated power. FERC rejected this argument and denied San Francisco's rehearing request. We deny the petition for review. FERC provided a reasoned explanation for its determination that San Francisco could not satisfy its local resource adequacy requirement with contractual rights to imported power. *See E. Tex. Elec. Coop., Inc. v. FERC*, 218 F.3d 750, 753 (D.C. Cir. 2000).

San Francisco's argument misconceives the nature of the local adequacy requirement. The requirement exists to ensure a minimum amount of capacity is available *within* the load pocket. FERC argues this requirement is necessary because the physical limits of transmission facilities make it impossible to reliably meet the demand for energy in load pockets with outside resources alone. *See* Second Market Redesign Order ¶ 601. A contingency such as a weather-related transmission outage could disrupt the ability to import energy, leaving San Francisco's residents powerless. The fact that San Francisco has contracted for imported power is irrelevant to this reality. As the intervenors supporting FERC put it, “contract rights will not keep the lights on.” Br. of Intervenors Supporting Resp’t at 43.

San Francisco contends that the ISO’s stance abrogates San Francisco’s existing contract rights and reduces their value, violating the ISO’s duty to honor any contract executed by San Francisco prior to April 1, 1998. *See Pac. Gas & Elec. Co.*, 81 FERC at 61,471–72. California ISO annually determines the amount of locally generated electricity required of San Francisco by calculating what it can and does import. *See* Second Market Redesign Order ¶ 601; First Market Redesign Order ¶ 1168. San Francisco suggests that the annual study insufficiently credits San Francisco for the full value of its existing transmission contracts. Pet’rs’ Br. on Tariff Charge Issues at 63, 64 & n.118. But San Francisco failed to challenge the methodology of the technical study before the Commission, so this argument is not properly before us. 16 U.S.C. § 825*l*(b); *see Jackson County v. FERC*, 589 F.3d 1284, 1291 (D.C. Cir. 2009).

The local resource adequacy requirement does not alter or diminish San Francisco’s preexisting contract rights. San Francisco continues to obtain the same resources for the agreed-upon price. Indeed, it may continue to satisfy customer demand however it sees fit using either locally generated or imported power, and could sell any excess power it generates. *See* Second Market Redesign Order ¶ 602. In fact, load-serving entities such as San Francisco need not meet their local resource adequacy requirement by generating electricity, but if they do not, they must shoulder the cost when California ISO makes up for any shortfall. Tariff Section 43.7.2. San Francisco faces a new obligation that cannot be satisfied with the power it imports under its existing contracts. To be sure, San Francisco did not anticipate this requirement when it made its current agreements. But the fact that San

Francisco may now value less the resources it obtains from its suppliers does not render FERC's decision to uphold the requirement arbitrary or capricious.

San Francisco argues that FERC's decision to allow California ISO to permit imported power to satisfy the system resource adequacy requirements but not the local requirements was arbitrary and capricious. Again, San Francisco's argument fails to understand the different reasons for the different requirements. California ISO implemented the system resource adequacy requirement to ensure adequate generation capacity within the ISO's balancing authority area as a whole. Each load-serving entity must show it has access to enough generating capacity to ensure reliable operation of the grid and proper functioning of the markets for electricity. Load-serving entities may satisfy this requirement with power imported from outside the load pocket. San Francisco argues that if California ISO found imported power sufficiently reliable to satisfy the system resource adequacy requirement, it was irrational to exclude it from the local calculation. But the system and local adequacy requirements serve different objectives. The local requirement exists to prevent local shortages, and does so by requiring a set level of local production. The aim of the system requirement is to prevent ISO-wide shortages by ensuring that the load-serving entities collectively have the capacity, whether by local production or by contract, to obtain power sufficient to meet the ISO's demand. First Market Redesign Order ¶ 1116. There is nothing arbitrary or capricious about permitting load-serving entities to satisfy these different requirements with different sources of power.

C.

Finally, we consider two challenges to California ISO's congestion revenue rights proposal. San Diego objects to the formula by which the ISO intends to allocate these rights, arguing that it will receive an inadequate share. Sacramento challenges the type of congestion revenue right FERC has approved, claiming the ISO must make available "option" rights as well as the proposed "obligation" rights. We reject both challenges.

1.

California ISO proposed allocating the initial congestion revenue rights based on transmission usage from April 2006 to March 2007. FERC approved the use of this reference period because it was "reasonably representative of the period during which the rates will be in effect," early enough that entities could not strategically enter into contracts to "cherry-pick[]" the most valuable congestion revenue rights, and yet recent enough that the data was not stale. Third Market Redesign Order ¶ 155.

San Diego claims it will receive too few congestion revenue rights because of its anomalously low transmission use from April 2006 to March 2007. San Diego speculates that it will be unable to make up for this shortfall by acquiring additional congestion revenue rights at later stages because demand will outstrip supply and holders of rights will sell them only at exorbitant prices. San Diego argues that it will be unable to acquire sufficient rights, and those that it purchases will be sold at inflated costs that it will have to pass on to its customers.

To address this scenario, San Diego proposed that the measure of transmission usage should include not only transmission between April 2006 and March 2007 but also all contracts for future delivery that were in place during that period. *Id.* ¶ 145. In the alternative, San Diego recommended that congestion revenue rights should be renewable only for the duration of the underlying contracts that governed transmission usage during the reference period, in contrast to the 10-year renewal permitted under the ISO's proposal. *Id.* ¶ 146.

FERC considered San Diego's proposals but declined to adopt either. Instead, FERC ordered California ISO to decrease the number of short-term congestion revenue rights that could be converted to long-term rights in the first years of the allocation process. *Id.* ¶ 157. California ISO originally proposed that entities could convert 50% of their load into long-term congestion revenue rights. In response, FERC required that the number start at 20% and rise to 50% over a three-year period. This change was intended to ensure that entities with higher initial allocations than San Diego would not be able to lock in long-term advantages. FERC reasoned that this approach would make more congestion revenue rights available in the free-choice tiers because rights that are not renewed revert to the free-choice tier and the ISO may allocate them to any party requesting them. At the same time, FERC's approach continues to provide load-serving entities "a degree of certainty that they can either acquire long-term . . . or renew short-term" congestion revenue rights. Fourth Market Redesign Order ¶ 31; *see also id.* ¶ 32.

San Diego requested rehearing, arguing that FERC's modification to the allocation process did not fully address its concerns. In denying rehearing, FERC reiterated that the limitations it placed on the conversion of short-term rights to long-term rights would ensure the availability of sufficient congestion revenue rights. *Id.* ¶¶ 28, 32. Any further limitations, FERC concluded, would not strike the best balance "between providing [entities] reasonable certainty that they can keep the [congestion revenue rights] associated with existing contracted resources and providing [them] with the flexibility to request new [congestion revenue rights] associated with future procurement decisions." *Id.* ¶ 32.

San Diego now argues that FERC's failure to provide an effective remedy to an acknowledged problem is arbitrary and capricious and inconsistent with section 205 of the Federal Power Act. When reviewing FERC's selection of a remedy, we give the Commission "great deference," *La. Pub. Serv. Comm'n v. FERC*, 522 F.3d 378, 393 (D.C. Cir. 2008), because "[a]gency discretion is often at its zenith" when the agency is fashioning remedies, *Towns of Concord, Norwood, & Wellesley v. FERC*, 955 F.2d 67, 76 (D.C. Cir. 1992) (internal quotation marks omitted). We extend this deference to "a predictive judgment by FERC about the effects of a proposed remedy for undue discrepancies among operating companies." *La. Pub. Serv. Comm'n v. FERC*, 551 F.3d 1042, 1045 (D.C. Cir. 2008). As we have often noted, we "will set aside FERC's remedial decision only if it constitutes an abuse of discretion." *La. Pub. Serv. Comm'n v. FERC*, 174 F.3d 218, 225 (D.C. Cir. 1999). We find no such abuse of discretion here.

FERC explained that its decision was a product of balancing the competing policy goals of flexibility and certainty. In administering the allocation of congestion revenue rights, FERC must ensure that the process is flexible enough that load-serving entities can acquire new congestion revenue rights in later years to accommodate their evolving needs, while simultaneously providing load-serving entities with assurances that they have reliable and long-term congestion hedges for their current transmission usage. Fourth

Market Redesign Order ¶¶ 28, 32. San Diego asks us to reject FERC's policy determination in favor of San Diego's own. This we will not do. FERC reflected on the competing interests at stake to explain why it struck the balance it did. "This court properly defers to policy determinations invoking the Commission's expertise in evaluating complex market conditions." *Tenn. Gas Pipeline Co. v. FERC*, 400 F.3d 23, 27 (D.C. Cir. 2005).

The Federal Power Act does not compel a different result. San Diego argues that the allocation process prevents it from acquiring the long-term transmission rights to which it is entitled under § 217(b)(4) of the Federal Power Act to support its long-term power supply arrangements. 16 U.S.C. § 824q(b)(4). But as we have explained, this claim boils down to a dispute between the competing predictions of FERC and San Diego about how the market for revenue rights will operate in the future. San Diego speculates that it will be unable to obtain the rights it needs either in the free-choice tier or through bilateral transactions, while FERC predicts that its modification to the allocation process will allow San Diego to meet those needs. Fourth Market Redesign Order ¶ 34. "[I]t is within the scope of the agency's expertise to make such a prediction about the market it regulates, and a reasonable prediction deserves our deference notwithstanding that there might also be another reasonable view." *Envtl. Action, Inc. v. FERC*, 939 F.2d 1057, 1064 (D.C. Cir. 1991). FERC's determination that the allocation process, taken as a whole, allows load-serving entities to obtain congestion revenue rights for both present and future needs was a reasonable one. Moreover, if, in the future, the allocation process results in an unjust outcome, San Diego may petition the Commission to order appropriate changes at that time under section 206 of the Federal Power Act, 16 U.S.C. § 824e (2006). *See* Fourth Market Redesign Order ¶ 34 n.36.

FERC's decision was also consistent with its precedent. San Diego cites several cases in which FERC excepted one market participant from rules applicable to other entities in order to ameliorate unjust results. *See New Eng. Power Pool*, 101 F.E.R.C. ¶ 61,344, at 62,431 (2002); *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 F.E.R.C. ¶ 61,163, at 61,928 (2004); *Sw. Power Pool*, 116 F.E.R.C. ¶ 61,162 (2006), *order on reh'g*, 118 F.E.R.C. ¶ 61,035 (2007). San Diego suggests that FERC should likewise afford it special treatment in light of the allegedly unjust share of revenue rights it will receive. But San Diego has not requested an exception so much as a complete redesign of the rule. No cited precedent compels the imposition of either of the particular remedies San Diego demands in this case. Because FERC did not act arbitrarily or capriciously in rejecting San Diego's proposed changes to the congestion revenue rights allocation process, we deny San Diego's petition for review on this issue.

2.

Sacramento challenges FERC's approval of California ISO's decision to offer obligation congestion revenue rights, but not option rights. These rights concern congestion costs, which are the costs associated with transmitting energy between two points on the grid with varying congestion. The holder of an obligation right is entitled to a payment from the ISO when the congestion at the source point is lower than the congestion at the withdrawal point. But when the situation is reversed—when congestion at the source point is higher than at the withdrawal point—the holder of the obligation right must make a payment to the ISO. By contrast, option rights include only the entitlement to receive payments from the ISO and carry no obligation to make payments.

Sacramento argues that the ISO's decision to offer only obligation rights violates Order No. 890, which requires that the ISO's pricing approach be comparable to the former physical rights system. Sacramento's argument boils down to a simple premise: With obligation rights, Sacramento faces the possibility of having to make congestion payments to the ISO. Under the physical rights system, it would never face this prospect. Therefore, Sacramento argues, the two systems are not comparable. FERC rejected Sacramento's request for option rights, concluding that the premise of its argument was flawed. FERC concluded that obligation rights are in fact equivalent to physical rights. Fourth Market Redesign Order ¶ 92. This conclusion was not arbitrary and capricious.

FERC relied on record evidence to explain its conclusion that obligation rights, when matched with a transmission schedule, are equivalent to physical rights, *see* J.A. 2274 (Prepared Direct Testimony of Dr. Susan L. Pope); J.A. 448 (Prepared Direct Testimony of Scott M. Harvey and Susan L. Pope); and "articulate[d] a satisfactory explanation for its action including a rational connection between the facts found and the choice made." *Williston Basin Interstate Pipeline Co. v. FERC*, 519 F.3d 497, 499 (D.C. Cir. 2008) (internal quotation marks omitted). Usually, the congestion cost of energy at its source point will be lower than the cost at its withdrawal point. In these circumstances, an entity with a schedule to transmit energy between these two points and a matching obligation congestion revenue right engages in two transactions with the ISO. First, the load-serving entity pays to the ISO the congestion cost associated with transmitting the electricity from the source point to the withdrawal point. Second, the ISO pays the holder of the matching congestion revenue right the same congestion cost. The net effect of these two transactions is that the load-serving entity pays zero if it holds the corresponding congestion revenue right. The result is the same in the unusual circumstance in which the congestion cost of energy at the source point is higher than at the withdrawal point. In these cases, the congestion cost associated with transmitting electricity is negative, and the load-serving entity receives a credit equal to the difference in congestion costs between the source point and the withdrawal point. The holder of the corresponding obligation right pays the ISO the same amount in congestion costs. Again, the net effect of these transactions is that if the load-serving entity also holds the corresponding congestion revenue right, it pays no congestion costs at all. Third Market Redesign Order ¶ 223. Accordingly, we hold that FERC's conclusion that "[a] party that submits a physical schedule that matches its obligation [congestion revenue right] should face little risk of negative payments," Fourth Market Redesign Order ¶ 94; *see also* Third Market Redesign Order ¶ 226, was rationally based on record evidence. *See Williston Basin*, 519 F.3d at 499.

III. Conclusion

For the foregoing reasons, the petitions for review are

Denied.