ORAL ARGUMENT SCHEDULED FOR FEBRUARY 25, 2010

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IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Nos. 07-1208*, et al.*

SACRAMENTO MUNICIPAL UTILITY DISTRICT*, ET AL.*
PETITIONERS,

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT.

ON PETITIONS FOR REVIEW OF ORDERS OF THE
FEDERAL ENERGY REGULATORY COMMISSION

BRIEF FOR RESPONDENT FEDERAL ENERGY REGULATORY COMMISSION

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COMMISSION
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DECEMBER 7, 2009

CIRCUIT RULE 28(a)(1) CERTIFICATE

A. Parties

All parties appearing before the Commission and this Court are listed in Petitioners' Rule 28(a)(1) certificates.

B. Rulings Under Review:

The rulings under review appear in the following orders issued by the Federal Energy Regulatory Commission:

1. *California Independent System Operator Corp.*, 116 FERC ¶ 61,274 (2006) ("First Market Redesign Order"), JA 1623;

2. *California Independent System Operator Corp.*, 119 FERC ¶ 61,076 (2007) ("Second Market Redesign Order"), JA 2428;

3. *California Independent System Operator Corp.*, 120 FERC ¶ 61,023 (2007) ("Third Market Redesign Order"), JA 3053;

4. *California Independent System Operator Corp.*, 124 FERC ¶ 61,094 (2008) ("Fourth Market Redesign Order"), JA 3395;

5. *California Independent System Operator Corp.*, 119 FERC ¶ 61,313 (2007) ("Compliance Order"), JA 2913; and

6. *California Independent System Operator Corp.*, 121 FERC ¶ 61,030 (2007) ("Compliance Rehearing Order"), JA 3231.

C. Related Cases:

This case has not previously been before this Court or any other court. Two subsequent appeals pending in this Circuit seek review of orders related to the orders contested here: *Sacramento Municipal Utility District v.*

FERC, No. 09-1141 (D.C. Cir. May 18, 2009) and *Sacramento Municipal Utility District v. FERC*, No. 09-1142 (D.C. Cir. May 18, 2009). The Court has granted motions to hold both cases in abeyance until disposition of the appeals at bar.

/s/ Samuel Soopper
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December 7, 2009

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GLOSSARY

California ISO	California System Operator Corporation
Commission	Federal Energy Regulatory Commission
Compliance Order	*Cal. Indep. Sys. Oper. Corp.*, 119 FERC ¶ 61,313 (2007)
Compliance Rehearing Order	*Cal. Indep. Sys. Oper. Corp.*, 121 FERC ¶ 61,039 (2007)
Congestion Revenue Rights Br.	Brief filed by Sacramento and San Diego
February 2006 Filing	R. 1, California ISO's February 9, 2006 Filing
FERC	Federal Energy Regulatory Commission
First Market Redesign Order	*Cal. Indep. Sys. Oper.Corp.*, 116 FERC ¶ 61,274 (2006)
Fourth Market Redesign Order	*Cal. Indep. Sys. Oper.Corp.*, 124 FERC ¶ 61,094 (2008)
FPA	Federal Power Act
Imperial	Imperial Irrigation District
June 2004 Guidance Order	*Cal. Indep. Sys. Oper. Corp.*, 107 FERC ¶ 61,274 (2004)
Marginal Loss/Resource Adequacy Br.	Brief filed by San Francisco, Imperial and Sacramento

Market Redesign	California ISO's comprehensive market redesign
Sacramento	Sacramento Municipal Utility District
San Diego	San Diego Gas & Electric Company
San Francisco	City and County of San Francisco, California
Second Market Redesign Order	*Cal. Indep. Sys. Oper.Corp.*, 119 FERC ¶ 61,076 (2007)
Third Market Redesign Order	*Cal. Indep. Sys. Oper. Corp.* 120 FERC ¶ 61,023 (2007)

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ON PETITIONS FOR REVIEW OF ORDERS OF THE
FEDERAL ENERGY REGULATORY COMMISSION

BRIEF OF RESPONDENT
FEDERAL ENERGY REGULATORY COMMISSION

STATEMENT OF THE ISSUES

Four petitioners[1] seek review of three of the dozens of issues addressed in a series of orders issued by the Federal Energy Regulatory Commission ("Commission" or "FERC"), approving a comprehensive redesign ("Market

[1] The petitioners are the City and County of San Francisco, California ("San Francisco"), the Imperial Irrigation District ("Imperial"), Sacramento Municipal Utility District ("Sacramento") and San Diego Gas & Electric Company ("San Diego").

Redesign") by the California System Operator Corporation ("California ISO") of the electricity markets it administers. The issues raised are:

1. Whether the Commission reasonably approved California ISO's proposal to use a Locational Marginal Pricing rate design (including a marginal loss component), based on its well-demonstrated economic and reliability benefits (Raised in the brief filed by San Francisco, Imperial and Sacramento ("Marginal Loss/Resource Adequacy Br.")).

2. Whether the Commission properly determined that California ISO's Resource Adequacy proposal, to ensure the necessary transmission capacity for electric reliability, was appropriate (Raised in the Marginal Loss/Resource Adequacy Br).

3. Whether the Commission reasonably determined that California ISO's Congestion Revenue Rights mechanism, to allow market participants to manage the costs of transmission congestion, should be adopted without certain modifications requested by two parties (Raised in the brief filed by Sacramento and San Diego ("Congestion Revenue Rights Br.")).

STATUTES AND REGULATIONS

The relevant statutes and regulations are contained in the Addendum to this brief.

INTRODUCTION

California ISO is a non-profit organization that operates, but does not own, the myriad transmission facilities in its system. *See Sacramento Municipal Utility District v. FERC*, 474 F.3d 797, 798 (D.C. Cir. 2007). This case involves the comprehensive redesign of California ISO's electric markets to create significantly greater reliability and economic efficiency.

While parties challenged many aspects of California ISO's proposed market redesign before the Commission, on appeal petitioners raise challenges to only a few aspects of the redesign: the use of marginal losses in Locational Marginal Pricing, the Resource Adequacy requirement, and the Congestion Revenue Rights system.

In a series of orders, the Commission found no merit to petitioners challenges, and conditionally approved California ISO's market redesign proposal as just and reasonable. *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 (2006) ("First Market Redesign Order"), JA 1623, *order on reh'g*, 119 FERC ¶ 61,076 ("Second Market Redesign Order"), JA 2428, *order on reh'g*, 120 FERC ¶ 61,023 (2007) ("Third Market Redesign Order"), JA 3053, *order on reh'g*, 124 FERC ¶ 61,094 (2008) ("Fourth Market Redesign Order"), JA 3395; *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,313 (2007) ("Compliance Order"), JA 2913, *order on reh'g*, 121 FERC ¶ 61,030 (2007) ("Compliance Rehearing Order"), JA 3231.

STATEMENT OF FACTS

I. Events Leading To The Challenged Orders

A. The Commission Requires California ISO To Redesign Its Markets

As early as 2000, the Commission recognized that there were fundamental structural problems with the efficiency and reliability of California ISO's system and directed the ISO to redesign certain aspects of its markets. *See* First Market Redesign Order P 12, JA 1635; *Cal. Indep. Sys. Operator Corp.*, 105 FERC ¶ 61,140 P 5 (2003); *Cal. Indep. Sys. Operator Corp.*, 90 FERC ¶ 61,006 at 61,013-14, *order on reh'g*, 91 FERC ¶ 61,026 (2000); *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 97 FERC ¶ 61,275 at 62,245 (2001).

California ISO initially submitted a market redesign proposal on May 1, 2002, but withdrew it after the Commission issued an order requiring substantial modifications. *Cal. Indep. Sys. Operator Corp.*, 100 FERC ¶ 61,060 (2002). First Market Redesign Order P 12, JA 1635-36. California ISO filed a new conceptual proposal on July 22, 2003, seeking guidance as to whether the Commission would find the proposed market redesign elements just and reasonable. *Id.*, JA 1636.

California ISO conducted an extensive stakeholder process both before and after submitting its conceptual proposal. First Market Redesign Order P 15, JA 1636; R. 1, California ISO's February 9, 2006 Filing ("February 2006 Filing"), Transmittal Letter at 13, JA 130; *id.* at Att. D at 2, JA 305; *id.* at Att. E, JA 308-15. In addition, the Commission held numerous technical conferences with California ISO and market participants, and issued more than 20 orders providing guidance on the conceptual market redesign proposal. First Market Redesign Order PP 13-14, JA 1636. On July 1, 2005, the Commission approved in principle California ISO's conceptual market redesign proposal. *Cal. Indep. Sys. Operator Corp.*, 112 FERC ¶ 61,013, *order on reh'g*, 112 FERC ¶ 61,310, *order on reh'g and technical conference*, 113 FERC ¶ 61,151 (2005).

B. California ISO's Market Redesign Proposal

After "more than six years of expert analysis, broad stakeholder input from those within and outside California, coordination with state authorities, and Commission guidance," First Market Redesign Order P 3, JA 1628, on February 9, 2006, California ISO submitted, pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, the market redesign proposal addressed in the challenged orders, R. 1.

California ISO explained that structural flaws in its prior system "led to excessive Congestion costs and inefficient use of the [California ISO]-controlled grid," and "failed to ensure that the resources necessary for reliability would be made available . . . ." R. 1, February 2006 Filing, Transmittal Letter at 1-2, JA 118-19. California ISO proposed to comprehensively overhaul its markets to remedy these flaws.

A key part of California ISO's proposal was to use Locational Marginal Pricing to manage congestion and effectively price energy and ancillary services. *Id.* at 15, JA 132. Under Locational Marginal Pricing, prices vary by location and time, and accurately reflect the least-cost of serving the next megawatt-hour of demand, including the marginal cost of transmission losses, at each location on the California ISO grid. First Market Redesign Order PP 10, 47, JA 1632, 1647-48. Transmission losses necessarily occur "[w]hen electricity is transmitted across power lines, [as] some portion of the energy is lost as heat. The loss is a function of (among other things) the length of the transmission and the square of the amount of current being transmitted." *Wis. Pub. Power Inc. v. FERC*, 493 F.3d 239, 252 (D.C. Cir. 2007). "Marginal losses reflect the marginal cost of transmission losses associated with serving an increment of load."[2] Second Market Redesign Order n.24, JA 2438.

[2] "'Load' simply refers to demand for service on a transmission grid." *Wis. Pub. Power*, 493 F.3d at 249 n.1.

California ISO explained that Locational Marginal Pricing would "more accurately price the true cost of using the grid and therefore should result in a more efficient and effective dispatch, *i.e.*, a dispatch that enables more efficient generation to be dispatched and compete for limited transmission capacity." R. 1, February 2006 Filing, Transmittal Letter at 15, JA 132. Unlike California ISO's prior system, under Locational Marginal Pricing the ISO would consider the marginal cost of transmission losses for each generator and dispatch the least-cost generator to serve each increment of load, decreasing the actual cost of meeting load. First Market Redesign Order PP 91 and 92 and n.84, JA 1661; *see also Atlantic City Elec. Co. v. PJM Interconnection, L.L.C,* 115 FERC ¶ 61,132 at P 4 (2006), cited First Market Redesign Order P 91, JA 1661 (same). "In addition," California ISO pointed out, "[Locational Marginal Pricing]-based markets will provide invaluable locational information to those considering long-run investments in new Generation, Load management, and other Demand resources." R. 1, February 2006 Filing, Transmittal Letter at 15, JA 132.

California ISO also proposed to require load-serving entities to meet both overall system and local resource adequacy requirements. California ISO explained that, "[a]s demonstrated by the 2000-2001 energy crisis in California, no market can function reliably, with reasonable prices and with limited volatility, in the absence of adequate infrastructure or resources. In order to maintain the reliability of the California electric grid and to serve customer needs, the [California ISO] must have the ability to serve Demand when and where it is needed." R. 1, February 2006 Filing, Transmittal Letter at 59, JA 176.

In addition, California ISO proposed a Congestion Revenue Rights program, which it described as a "critical piece" of the entire Market Redesign. R. 1, February 2006 Filing, Transmittal Letter at 23, JA 140. Specifically, the ISO explained, "[Congestion Revenue Rights] will allow Market Participants to obtain financial protection for the risk of Congestion Charges associated with the [Locational Marginal Pricing]-based Congestion Management design." *Id.*

At first, the ISO proposed only short-term Congestion Revenue Rights, *i.e.*, with terms of less than a year. These Congestion Revenue Rights initially would be released to load-serving entities by means of an allocation process, after which California ISO would conduct an auction for the Congestion Revenue Rights remaining. *Id.* at 26-27, JA 143-44.

Congestion Revenue Rights would be allocated according to a tier system. For the first year of market operations under the Market Redesign Tariff (designated Year One), nominations for the priority tiers (Tiers 1 and 2), would have to be "source verified," *i.e.*, to be eligible for allocation in Tiers 1 and 2, a load-serving entity would have 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." *Id.* at 29, JA 146.

Originally, California ISO proposed that the historical reference period for source verification would be from September 1, 2004, until August 31, 2005. Because initiation of the Market Redesign Tariff was postponed several times, however, the actual historical reference period was correspondingly updated.

C. California ISO's Long-Term Congestion Rights Proposal

Section 1233 of the Energy Policy Act of 2005 added section 217 to the FPA, which provides, as relevant here, that the Commission shall exercise its statutory authority:

> in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load serving-entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.

16 U.S.C. § 824q(b)(4). Section 1233(b) of the Act further instructed the Commission to implement this provision by rule or order within a year of its enactment (*i.e.*, by August 5, 2006). Pub. L. No. 109-58, 119 Stat. 960.

In response, on July 20, 2006, the Commission issued a Final Rule amending its regulations to require transmission organizations that are public utilities with organized electricity markets, such as California ISO, to make available long-term firm transmission rights pursuant to certain established guidelines. *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, FERC Stats. & Regs. ¶ 31,226 (2006), *order on reh'g*, Order No. 681-A, 117 FERC ¶ 61,201(2006), *order on reh'g*, Order No. 681-B, 126 FERC ¶ 61,254 (2009), *appeal pending sub nom. Sacramento Municipal Utility District v. FERC*, No. 09-1141 (D.C. Cir. May 18, 2009) (The guidelines are codified at 18 C.F.R. § 42.1(d), and are included in the Statutory and Regulatory Appendix to this brief). The regulations further directed organized transmission markets to make filings with the Commission by January 29, 2007, of either "[t]ariff sheets and rate schedules that make available long-term firm transmission rights that satisfy" the regulatory guidelines, or an explanation of how its current tariff sheet and rate schedules meet this criterion. 18 C.F.R. § 42.1(c)(1)(i)-(ii).

On January 29, 2007, California ISO filed its proposal "to provide long-term firm transmission rights in its markets" in compliance with Order Nos. 681 and 681-A. R. 435, *et seq.*, January 29, 2007 Filing (January 2007 Filing) at 1, JA 2222. California ISO stated that its long-term firm transmission rights, called Long Term Congestion Revenue Rights, satisfied each of the seven guidelines set out in the agency's Final Rule. *Id.* at 1-2, JA 2222-23.

California ISO proposed to implement its long-term Congestion Revenue Rights by building on the short-term program already approved by the Commission. January 2007 Filing, Transmittal Letter at 10, JA 2231. Specifically, the ISO explained, it was introducing "a new allocation tier (Tier LT) after Tier 1 and Tier 2 in the [Congestion Revenue Rights] allocation process for [Congestion Revenue Rights] Year One." *Id.* (footnote omitted).

Thus, the long-term Congestion Revenue Rights process consists of a four tier process which allows load-serving entities to nominate a certain number of such rights based upon their grid usage. Once the source-verified nominations for Tiers 1 and 2 are completed in the first year of Market Redesign operation, load-serving entities can then nominate any such rights they received for long-term status in the LT Tier. January 2007 Filing, Transmittal Letter at 12, JA 2233.

While California ISO initially proposed eligibility for long-term Congestion Revenue Rights in year one to be 50% of a load-serving entity's adjusted load metric (a calculation which measures an entity's exposure to congestion charges), the Commission preferred a more gradual approach, to help strike an appropriate balance between providing certainty to entities that had already made long-term procurement decisions and flexibility for those needing to nominate Congestion Revenue Rights to match future procurement. Third Market Redesign Order PP 136-37, JA 3098. Thus, the agency generally reduced the eligibility for long-term

Congestion Revenue Rights to 20% of a load-serving entity's adjusted load metric the first year of Market Redesign operation. (The percentage increases 10% annually in subsequent years until it reaches 50%). *See Id.* P 136, JA 3098.

Following the long-term tier is Tier 3 (actually the fourth tier), a flexible choice tier that permits load-serving entities to nominate Congestion Revenue Rights from any source. January 2007 Filing, Exh. ISO-1 (Kristov testimony) at 32, JA 2389.

Finally, California ISO holds an auction of any remaining Congestion Revenue Rights. However, at any stage in the process, a load-serving entity may obtain Congestion Revenue Rights through bilateral transactions, either by sale or trade, to best match its needs. *See* First Market Redesign Order P 707, JA 1824.

After the first year of operation, the four-tiered Congestion Revenue Rights process continues, but without source verification. Rather, Tier 1 allocations are based upon the Priority Nomination Process, so that load-serving entities have the option of re-nominating previously allocated Congestion Revenue Rights, whether or not they initially had been source verified. Third Market Redesign Order P 164, JA 3107. Additionally, in the second and third tiers, a load-serving entity would be able flexibly to nominate its previously nominated short-term rights for long-term status. *Id.*

Two of California ISO's specific Congestion Revenue Rights proposals are raised on appeal. First, the ISO proposed that the "historical reference period for source verification [be] changed to calendar year 2006." January 2007 Filing, Transmittal Letter at 9 (footnote omitted), JA 2230. Second, California ISO proposed that, like their short-term brethren, "Long Term [Congestion Revenue Rights] also be obligations," January 2007 Filing, Transmittal Letter at 10, JA 2231. This meant that the holder of a long-term Congestion Revenue Right would not only receive congestion revenues, but also would be obligated "to pay congestion charges in certain circumstances depending on whether the difference between the congestion components of the [Locational Marginal Price] at the source [*i.e.*, receipt point] and the [Locational Marginal Price] at the sink [*i.e.*, delivery point] is positive or negative." *Id.* at 10 n.31, JA 2231.

II. The Challenged Orders

The challenged orders approved as just and reasonable California ISO's proposal to redesign its markets to provide for, among other things, Locational Marginal Pricing (including a marginal loss component), Resource Adequacy requirements, and Congestion Revenue Rights.

As the Commission explained, Locational Marginal Pricing with a marginal loss component would promote efficient use of the transmission grid and use of the lowest-cost generation, provide for transparent price signals, and enable California

ISO to operate the grid more reliably. *See*, *e.g.*, First Market Redesign Order PP 63, 90, JA 1653, 1661. Furthermore, the Commission found California ISO's proposed Resource Adequacy requirements were critical for reliable operation of the grid and functioning of California ISO's markets, as well as to ensure that rates and services would be just and reasonable. *See*, *e.g.*, Second Market Redesign Order P 551, JA 2644.

The Commission also found California ISO's Congestion Revenue Rights proposal just and reasonable and not unduly discriminatory. *See*, *e.g.*, Fourth Market Redesign Order P 28, JA 3404-05. Specifically, the Commission determined, California ISO's "proposed source verification process and its use of the 2006 historical reference period is a reasonable means to establish 'priority' [Congestion Revenue Rights] nominations in [Market Redesign] year 1." *Id.* Moreover, California ISO's proposal to provide only obligation and not option Congestion Revenue Rights was equivalent to physical rights and satisfied the requirements of Order Nos. 681 and 681-A. Third Market Redesign Order P 226, JA 3130; Fourth Market Redesign Order P 92, JA 3429-30.

SUMMARY OF ARGUMENT

<u>Locational Marginal Pricing</u>

The Commission reasonably approved California ISO's proposal to implement Locational Marginal Pricing with a marginal loss component as part of its Market Redesign. The significant benefits of this rate design – improved price signals, greater market transparency, more efficient use of the transmission grid, including encouraging appropriate generation and transmission investment – are well-established both by substantial evidence in the present record, as well as the fact that Locational Marginal Pricing mechanisms with marginal loss components have already been successfully established in other major organized electricity markets.

The Commission also was on firm regulatory ground when it approved the use of load aggregation point pricing for load (*i.e.*, average locational marginal prices within California ISO's pre-existing pricing zones) as a transitional mechanism. As demonstrated by both the evidence in the record and experience in other organized markets, this transitional measure will provide economic efficiency benefits, while tempering the immediate impact of Locational Marginal Pricing on ratepayers.

Furthermore, the Commission reasonably found California ISO's proposal was just and reasonable without a marginal loss hedge. The Commission already had determined, in its Order No. 681 rulemaking, that regional transmission organizations are not required to provide marginal loss hedges.

The Commission also appropriately found that, because entities will be able to conservatively estimate losses, the marginal loss proposal preserves self-supply consistent with Order No. 888.

There also is no merit to challenges to the mechanism approved to allocate excess marginal loss revenues. Crediting on a load-ratio share basis ensures that load will pay the correct amount (marginal cost) for energy, that the marginal loss price signal will not be distorted, and is consistent with cost-causation principles and this Court's precedent.

Finally, the Commission reasonably found that marginal losses should apply to transmission ownership rights transactions that involve injections and withdrawals from the California ISO grid. As the Commission explained, applying marginal losses to transmission ownership rights is no different than applying them to other import and export schedules.

Resource Adequacy

California ISO's proposed resource adequacy requirements are critical to the reliable operation of the grid, proper functioning of California ISO's markets, and to ensure just and reasonable rates. As California ISO will calculate each local resource adequacy requirement as the amount of capacity that cannot be met with capacity outside a load pocket due to transmission limitations, the Commission reasonably approved California ISO's proposed requirement that local resource adequacy requirements be met by resources within a load pocket.

California ISO's local resource adequacy requirement does not interfere with San Francisco's preexisting contract rights. San Francisco retains the full rights of its existing transmission contract to transmit power from outside a load pocket; it simply may not use resources outside a load pocket to satisfy local resource adequacy requirements.

Congestion Revenue Rights

The Commission reasonably approved California ISO's Congestion Revenue Rights proposal as an appropriate mechanism to provide long-term firm transmission rights as part of its Market Redesign.

More specifically, the Commission appropriately determined that using California ISO's proposed historical reference period as a measure by which market participants would initially nominate Congestion Revenue Rights was reasonable. The designated period was reasonably representative of the market, and prevented parties from strategically altering supply decisions in order to cherry-pick the most valuable rights. The Commission also appropriately held that the one party objecting to the historical period had not met its burden to demonstrate that it would suffer discrimination in acquiring sufficient Congestion

Revenue Rights. Rather, the Commission found that that party's needs should be met because of certain adjustments the agency mandated in the Congestion Revenue Rights rate design, as well as the flexibility for acquiring such rights already built into the program.

Second, the Commission reasonably approved California ISO's proposal to offer only obligation-type, as opposed to option-type, Congestion Revenue Rights. There was substantial evidence in the record that obligation rights would provide greater congestion relief, while limiting financial risk to market participants. Thus, the agency determined that obligation-type Congestion Revenue Rights met all necessary statutory and regulatory requirements.

ARGUMENT[3]

I. STANDARD OF REVIEW

The Court reviews FERC orders under the Administrative Procedure Act's arbitrary and capricious standard. *Wis. Pub. Power*, 493 F.3d at 256. Under that standard, the Commission's decision must be reasoned. *East Texas Elec. Coop., Inc. v. FERC*, 218 F.3d 750, 753 (D.C. Cir. 2000). For this purpose, the Commission's factual findings are conclusive if supported by substantial evidence

[3] On November 2, 2007, the Court directed the parties to address in their briefs the issues presented in FERC's July 19, 2007 Motion to Dismiss. In light of subsequent events, the Commission has determined that it no longer intends to pursue dismissal of the petitions for review.

in the record. *Id.*; FPA § 313(b), 16 U.S.C. § 825*l*(b). Moreover, the "'question is not whether record evidence supports petitioners' version of events, but whether it supports FERC's.'" *Wis. Pub. Power*, 493 F.3d at 266-67 (quoting *Ariz. Corp. Comm'n v. FERC*, 397 F.3d 952, 954 (D.C. Cir. 2005)).

The Court "recogniz[es] that 'matters of rate design . . . are technical and involve policy judgments at the core of FERC's regulatory responsibilities. Hence, the court's review of whether a particular rate design is just and reasonable is highly deferential.'" *Wis. Pub. Power*, 493 F.3d at 256 (quoting *Me. PUC v. FERC*, 454 F.3d 278, 287 (D.C. Cir. 2006); *see also Blumenthal v. FERC*, 552 F.3d 875, 881 (D.C. Cir. 2009) ("the statutory requirement that rates be 'just and reasonable' is obviously incapable of precise judicial definition, and we afford great deference to the Commission in its rate decisions") (quoting *Morgan Stanley Capital Group, Inc. v. Pub. Util. Dist. No. 1*, 128 S. Ct. 2733, 2738 (2008)).

In addition, "[i]n evaluating FERC's interpretation of its own order[s], [the Court] afford[s] the Commission substantial deference, upholding the agency's decision 'unless its interpretation is plainly erroneous or inconsistent' with the order[s]." *Consumers Energy Co. v. FERC*, 428 F.3d 1065, 1067-68 (D.C. Cir. 2005).

II. THE COMMISSION REASONABLY APPROVED THE USE OF MARGINAL, RATHER THAN AVERAGE, LOSSES

A. The Benefits Of Using Marginal Losses Are Well-Established

By the time the First Market Redesign Order issued, Locational Marginal Pricing mechanisms with marginal loss components already had been successfully implemented in other organized electric markets. First Market Redesign Order PP 25, 63, JA 1641, 1653.[4] As the Commission found in this (and those other cases), Locational Marginal Pricing with a marginal loss component provides substantial benefits. Second Market Redesign Order P 41 and nn.64-65, JA 2447-48 ("The benefits of using marginal losses are well documented.[[5]]").

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[4] *See also Atlantic City*, 115 FERC ¶ 61,132 at PP 4, 22-24; *New PJM Co.*, 107 FERC ¶ 61,271 at P 55 n.68 (2004); *Pennsylvania-New Jersey-Maryland Interconnection*, 81 FERC ¶ 61,257 at 62,253 (1997) (regarding Locational Marginal Pricing in the PJM Interconnection, L.L.C.); *Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,196 at PP 53, 56, *order on reh'g*, 103 FERC ¶ 61,210 at PP 28-29 (2003) (regarding Locational Marginal Pricing in the Midwest Independent System Operator); *New England Power Pool*, 100 FERC ¶ 61,287 at PP 64, 71, *order on reh'g*, 101 FERC ¶ 61,344 (2002); *Northeast Utils. Serv. Co.*, 105 FERC ¶ 61,122 at PP 18-20 (2003), *order on reh'g*, 109 FERC ¶ 61,204 at PP 14-15 (2004) (regarding Locational Marginal Pricing in ISO New England); *Central Hudson Gas & Elec. Corp.*, 86 FERC ¶ 61,062, *order on reh'g*, 88 FERC ¶ 61,138 (1999), *pet. for review granted in part, sub nom. Sithe/Indep. Power Partners v. FERC*, 285 F.3d 1 (D.C. Cir. 2002) (regarding Locational Marginal Pricing in the New York Independent System Operator).

[5] Citing, *e.g.*, R. 1, February 2006 Filing, Att. F (Kristov Testimony) at 25, JA 340; *id.* Att. I (Rahimi Testimony) at 40-46, JA 886-92; *Midwest ISO*, 102 FERC ¶ 61,196 at P 53; *Central Hudson*, 88 FERC ¶ 61,138 at 61,384-85; *New England*

Specifically, Locational Marginal Pricing "communicate[s] the true market value of electricity at each location, . . . creat[ing] financial incentives to dispatch the lowest cost energy . . . ." First Market Redesign Order P 10, JA 1632. Moreover, "[i]n the long-term, by making energy and congestion prices more transparent, locational marginal pricing will help encourage transmission and generation investment at appropriate locations, as well as demand response." *Id.*; *see also*, *e.g.*, Second Market Redesign Order P 21, JA 2438-39 (same). Thus, Locational Marginal Pricing "promote[s] efficient use of the transmission grid, promote[s] the use of the lowest-cost generation, provide[s] for transparent price signals, and enable[s] transmission grid operators to operate the grid more reliably." First Market Redesign Order P 63, JA 1653.

B. The Commission Reasonably Found That Using Marginal Losses Would Provide Benefits

Sacramento and Imperial claim that the challenged orders conflicted with statements in an earlier Commission Guidance Order. Marginal Loss/Resource Adequacy Br. 21-24. Even if that claim were correct (which, as explained immediately below, it is not), it would not help Sacramento and Imperial. The Commission "conducted a *de novo* review" of the challenged California ISO

Power Pool, 100 FERC ¶ 61,287; *Northeast Util. Serv.*, 105 FERC ¶ 61,122, 109 FERC ¶ 61,204.

Market Redesign proposal. First Market Redesign Order n.44, JA 1644. As a result, statements made in a Guidance Order regarding California ISO's earlier conceptual proposal were not binding on the Commission in its review in the challenged orders of California ISO's later Market Redesign proposal.

In any case, Sacramento and Imperial's claim is incorrect. Sacramento and Imperial first contend that "FERC's conclusion [in the challenged orders] that using marginal losses would 'necessarily' lower costs contradicted its finding [in *Cal. Indep. Sys. Oper. Corp.*, 107 FERC ¶ 61,274 at P 147 (2004) ("June 2004 Guidance Order")] that if a cost-benefit inquiry established the contrary, California ISO 'may file to use average losses.'" Marginal Loss/Resource Adequacy Br. at 21 (capitalization in heading altered); *see also id.* at 22-24 (expanding on argument and citing to Second Market Redesign Order P 41, JA 2447, and June 2004 Guidance Order, 107 FERC ¶ 61,274 at P 147).

In Sacramento's view, FERC's finding in the challenged orders that "the use of marginal losses will necessarily reduce the cost of meeting load because it will take full account of the effect of losses on the marginal cost of delivering alternative sources of energy to load," Second Market Redesign Order P 41, JA 2448 (citing First Market Redesign Order P 92, JA 1661), contradicted statements in the June 2004 Guidance Order, 107 FERC ¶ 61,274 at P 147, that the Commission "would be concerned if [applying a marginal loss approach] were to substantially raise implementation costs of the [California ISO]'s market redesign," and, therefore, "if in the process of further developing the marginal loss proposal and tariff language the [California ISO] and market participants determine that use of average losses at inception would be more easily administered and less costly, then [California ISO] may file to use average losses when it makes its tariff filing." Marginal Loss/Resource Adequacy Br. at 21-23.

In fact, however, FERC's finding that "the *use* of marginal losses would necessarily reduce the cost of meeting load," Second Market Redesign Order P 41, JA 2448 (emphasis added), was unrelated to its earlier statement (made during the conceptual proposal stage) that marginal losses might substantially increase the costs of *implementing* the market redesign, June 2004 Guidance Order, 107 FERC ¶ 61,274 at P 147 (emphasis added). The June 2004 Guidance Order statement addressed the Commission's potential concern that "*implementing* marginal losses would be substantially more costly than *implementing* average losses."[6] Second Market Redesign Order P 46, JA 2450 (emphasis added). By contrast, the Commission's finding in the challenged orders that "the *use* of marginal losses will *necessarily reduce the cost of meeting load*" did not address market redesign

[6] This concern was allayed when California ISO's Market Redesign proposal "neither represent[ed] to the Commission that using marginal losses would raise the implementation cost of [the market redesign], nor . . . propose[d] to use average losses." Second Market Redesign Order P 46, JA 2450.

implementation costs but, rather, one of the well-documented benefits of *using* marginal losses. Second Market Redesign Order P 41, JA 2448 (emphases added) (citing, *e.g.*, R. 1, February 2006 Filing, Att. F (Kristov Testimony) at 25, JA 340; *id.* Att. I (Rahimi Testimony) at 40-46, JA 886-92; *Midwest ISO*, 102 FERC ¶ 61,196 at P 53; *Central Hudson*, 88 FERC ¶ 61,138 at 61,384-85; *New England Power Pool*, 100 FERC ¶ 61,287; *Northeast Util. Serv.*, 105 FERC ¶ 61,122, *reh'g denied*, 109 FERC ¶ 61,204).

Sacramento and Imperial also assert that the Commission's benefits finding conflicted with certain witness testimony. Marginal Loss/Resource Adequacy Br. at 23 (citing R.30, Exh. SMD-1, at 26-29, 72-79, JA 1191-94, 1206-13). "Of course," however, "the 'question is not whether record evidence supports petitioners' version of events, but whether it supports FERC's.'" *Wis. Pub. Power*, 493 F.3d at 266-67 (quoting *Arizona*, 397 F.3d at 954). Here, substantial record evidence (*e.g.*, Second Market Redesign Order P 41, JA 2447-48 (citing, *e.g.*, R. 1, February 2006 Filing, Att. F (Kristov Testimony) at 25, JA 340; *id.* Att. I (Rahimi Testimony) at 40-46, JA 886-92)) supported FERC's benefits findings, which, therefore, should be upheld.

There also is no merit to Sacramento and Imperial's contention that the Commission improperly approved the use of marginal losses based solely on economic theory and the theoretical benefits of the marginal loss methodology.

Marginal Loss/Resource Adequacy Br. at 23-24 (citing *Elec. Consumers Res. Council v. FERC*, 747 F.2d 1511, 1514, 1518 (D.C. Cir. 1984)). The Commission did not rely only on economic theory and theoretical benefits. Rather, as the Commission noted, Locational Marginal Pricing mechanisms with marginal loss components already had been implemented successfully in a number of other Regional Transmission Organizations' markets when the Commission approved the Locational Marginal Pricing proposal here. First Market Redesign Order PP 25, 63, JA 1642, 1653.[7]

In any event, the Commission appropriately could have relied solely on economic theory and theoretical benefits in making its findings here. This Court has "rejected the idea that '*Electricity Consumers*' reference to 'economic theory' was intended to invalidate agency reliance on generic factual predictions merely because they are typically studied in the field called economics.'" *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 688 (D.C. Cir. 2000) (citing *Assoc. Gas Distribs. v. FERC*, 824 F.2d 981, 1008 (D.C. Cir. 1987)).

Moreover, contrary to Sacramento and Imperial's claim, Marginal Loss/Resource Adequacy Br. at 22, the Guidance Order did not find that California ISO's "use of marginal losses would *not* necessarily produce benefits." Rather, that Order explicitly "accept[ed] the [California ISO]'s [conceptual] proposal to

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[7] *See* cases cited n.4.

use marginal losses in its calculation of [Locational Marginal Prices] because this approach helps to assure a least-cost dispatch." June 2004 Guidance Order, 107 FERC ¶ 61,274 at P 142.

Sacramento and Imperial next contend that the June 2004 Guidance Order required California ISO to consult with its stakeholders and conduct a cost-benefit analysis regarding whether to propose the use of marginal losses. Marginal Loss/Resource Adequacy Br. at 23-24. Interpreting its own order, however, the Commission reasonably determined otherwise. Second Market Redesign Order P 46, JA 2450.

As the Commission found, the June 2004 Guidance Order required additional action or explanation by California ISO only if it proposed using average, rather than marginal, losses. *Id.* (citing June 2004 Guidance Order, 107 FERC ¶ 61,274 at P 147). Because California ISO proposed to use marginal losses and did not indicate any concern that doing so would raise market redesign implementation costs, no explanation was required here. *Id.* While Sacramento and Imperial contend the June 2004 Guidance Order required more, Marginal Loss/Resource Adequacy Br. at 22-23, the Commission's reasonable interpretation of its own order, not Sacramento and Imperial's alternative interpretation, is due deference and should be upheld. *Wis. Pub. Power*, 493 F.3d at 266; *Entergy Services, Inc. v. FERC*, 375 F.3d 1204, 1209 (D.C. Cir. 2004).

C. FERC Reasonably Approved The Transitional Use of Load Aggregation Points Rather Than Full Locational Marginal Pricing

Imperial claims that, because load will be charged average zonal marginal prices rather than full Locational Marginal Prices during the early stage of the market redesign, California ISO's Locational Marginal Pricing mechanism will not provide benefits. Marginal Loss/Resource Adequacy Br. at 36. As the Commission found, this claim has no merit. Second Market Redesign Order P 37, JA 2445-46.

In its Market Redesign proposal, California ISO noted that "California's transmission grid was not built with the expectation that the system would be used to support [a Locational Marginal Pricing]-based market," and that applying full locational pricing "for the initial release of the [market redesign] could result in extremely high prices to consumers in congested areas resulting from constraints in a transmission system that was designed and constructed under an entirely different regulatory regime . . . ." R. 1, February 2006 Filing, Transmittal Letter at 20, JA 137. California ISO proposed, therefore, that, while suppliers would be paid full locational marginal prices, load initially would be charged Load Aggregation Point prices. *Id.*; *see also id.* Att. F (Kristov Testimony) at 27-29, JA 342-44; First Market Redesign Order PP 26, 49, 595, 596, 599, and nn.50 and 278, JA 1642, 1648, 1793, 1795. Thus, for load California ISO would calculate a price for each of three zones based upon the weighted average of the locational marginal prices within that zone. First Market Redesign Order P 596, JA 1793-94.

The Commission approved this proposal, finding that it "provides a reasonable and simplified approach for introducing [Locational Marginal Pricing], while minimizing its impact on load." First Market Redesign Order P 611, JA 1798 (citing several guidance orders: *Cal. Indep. Sys. Operator*, 105 FERC ¶ 61,140; *Cal. Indep. Sys. Operator Corp.*, 112 FERC ¶ 61,013 (2005); *Cal. Indep. Sys. Operator Corp.*, 112 FERC ¶ 61,310 (2005); *Cal. Indep. Sys. Operator Corp.*, 113 FERC ¶ 61,151 (2005)); *see also* Second Market Redesign Order P 19, JA 2437 (same); *ISO New England, Inc.*, 91 FERC ¶ 61,311 at 62,070 (2000) (approving the use of Load Aggregation Point pricing as "a reasonable initial approach to congestion pricing" for ISO New England, and noting that similar pricing was approved for the New York ISO and PJM). Although acknowledging that Load Aggregation Point pricing "may not be the optimal solution" for the "economic hardship on entities located in load pockets," the Commission "found it to be a just and reasonable transition mechanism." First Market Redesign Order P 611, JA 1798. Second Market Redesign Order P 19, JA 2438 (citing *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 at P 68 (2006); *Midwest Indep. Transmission Sys. Operator*, 109 FERC ¶ 61,157 at P 80 (2004)).

The Commission explained that, even in the initial period when load pays [Load Aggregation Point] prices, California ISO's proposal will provide economic efficiency benefits. First Market Redesign Order PP 603, 607, 614, JA 1796, 1797, 1799; Second Market Redesign Order P 37, JA 2445. For example, it will provide the California ISO and transmission investors with improved congestion price signals. First Market Redesign Order PP 603, 607, 614, JA 1796, 1797, 1799.

In addition, the Commission found, California ISO's proposal will ensure least-cost dispatch. Second Market Redesign Order P 37, JA 2445. "In choosing among alternative sources of supply, a load (purchasing bilaterally) or the [California ISO] (in purchasing for the spot market) will need to consider which [suppliers] have the lower delivered cost to the load," including marginal loss and congestion costs. *Id.* Since all suppliers will receive full Locational Marginal Prices, the difference in marginal losses among the suppliers will be the same whether load pays a full Locational Marginal or Load Aggregation Point price. *Id.*; *see also id.* n.60, JA 2446 (providing illustrative example). "Thus, the ranking of resources in terms of relative delivered costs will be the same whether loads pay nodal [*i.e.*, full Locational Marginal] or zonal [*i.e.*, Load Aggregation Point] costs." *Id.*

Noting, however, that full Locational Marginal Pricing "sends more accurate price signals to load and, therefore, can encourage more demand response, which is an important element in mitigating market power and promoting an efficient market," the Commission authorized Load Aggregation Point pricing for load solely as a transitional mechanism. First Market Redesign Order P 614, JA 1799. Accordingly, the Commission directed California ISO to increase the number of Load Aggregation Point zones in phase two of the market redesign, and then to move to full Locational Marginal Pricing for load. Second Market Redesign Order P 19, JA 2437; *see also* First Market Redesign Order PP 611, 614, JA 1798, 1799.

D. FERC Appropriately Found Locational Marginal Pricing Just And Reasonable Without A Marginal Loss Hedge

Sacramento claims that California ISO's "proposal to change its tariff to include marginal losses, but without a hedging mechanism, contravened Order 890," *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007). Marginal Loss/Resource Adequacy Br. at 26; *see also id.* at 27-28.

In support of its claim, Sacramento cites to Order No. 890's requirement that transmission providers proposing tariff changes that deviate from the *pro forma* Order No. 890 tariff demonstrate that the proposal will provide customers with service that is consistent with or superior to that available under the *pro forma* tariff. Marginal Loss/Resource Adequacy Br. at 26 (citing Order 890 P 157). Sacramento also cites to Order No. 681 and *Cal. Indep. Sys. Oper. Corp.*, 87 FERC

¶ 61,143 at 61,570-72 (1999), for the proposition that a congestion charge hedge is required to meet the "consistent with or superior to" standard. Marginal Loss/Resource Adequacy Br. at 27 and n.18. Sacramento argues, therefore, that a marginal loss hedge also is required to meet that standard.

As the Commission explained, however, it "already decided in [its Order No. 681 rulemaking]," in response to a claim by Sacramento, "that [regional] transmission organizations are not required to provide marginal loss hedges." Third Market Redesign Order P 229, JA 3132-32 (citing Order No. 681 P 478; Order No. 681-A PP 105-05); *see also* Fourth Market Redesign Order P 95, JA 3430 (same); Order No. 681 P 477 (setting out Sacramento's claim); Order No. 681-A P 104 (same); *see also Sacramento Municipal Utility District v. FERC*, 428 F.3d 294, 298-99 (D.C. Cir. 2005) (rejecting, as an impermissible collateral attack, Sacramento's challenge to FERC finding in a rulemaking made in response to matter raised by a party to that rulemaking).

Furthermore, the Commission found no merit to the claim that the physical firm transmission rights provided under the *pro forma* Order No. 890 tariff were superior to California ISO's proposal. Third Market Redesign Order P 247, JA 3139. "In the past, physical firm transmission rights were provided by contract, and those agreements generally assigned to transmission customers the cost of losses, or a percentage of losses, which were calculated on an average loss basis."

Id. While Locational Marginal Pricing will expose transmission customers to marginal, rather than average, loss charges, the Commission explained, those customers will greatly benefit from the use of marginal losses. *Id.* (citing record evidence and precedent regarding the well-documented benefits of using marginal losses listed in n.5 *supra*); Second Market Redesign Order P 42, JA 2448 ("we find that the overall benefits of marginal losses outweigh the perceived difficulties in hedging marginal losses"); Fourth Market Redesign Order P 100, JA 3432 (same).

In fact, the Commission determined that the proposal's "'total package' of [Locational Marginal Pricing] and [Congestion Revenue Rights] is superior to a pure physical rights regime. [Locational Marginal Pricing] will result in more efficient, least-cost dispatch, and signal where investment is needed in generation and/or transmission. This efficiency, combined with long-term [Congestion Revenue Rights] that will help provide increased certainty regarding the congestion cost risks of long-term transmission service in organized electricity markets, will help . . . market participants make efficient investment decisions and long-term power supply arrangements." Third Market Redesign Order P 246, JA 3139 (citing Order No. 681 P 473 (finding that organized markets with Locational Marginal Pricing generally improve the firmness of physical transmission scheduling by reducing the incidence of transmission loading relief); Order No. 890 P 625 ("We believe that [Locational Marginal Pricing] market designs can provide significant benefits to customers through the more efficient use of the grid")); *see also* Third Market Redesign Order P 252, JA 3142 ("we find, on balance, the combination of physical scheduling rights and financial transmission rights under the [proposal] are superior to a pure physical rights approach"). As a result, the Commission noted, it already had approved similar marginal loss provisions (*i.e.*, without hedges) for other Regional Transmission Organizations. *Id.* P 247, JA 3139-40.

The Commission also pointed out that "it is much more difficult to design a marginal loss hedge than a congestion hedge, in part due to the variables that influence marginal losses, such as ever-shifting line loading." Second Market Redesign Order P 446, JA 2596; *see also* Fourth Market Redesign Order P 95, JA 3431 (same). "Consequently, while theoretically possible, to date no one has designed a workable marginal loss hedge, so no transmission organization has been able to implement one." Third Market Redesign Order P 229, JA 3132 (citing Order No. 681-A P 105); *see also* Second Market Redesign Order P 42, JA 2448 ("no other [Regional Transmission Organization] or [Independent System Operator] has been able to develop a hedging mechanism for marginal losses because, as [California ISO] pointed out, hedging mechanisms for marginal losses are in the experimental stage"); Fourth Market Redesign Order P 95, JA 3431 (same). "Indeed, none of the parties in this case ha[d] offered such a hedge." Second Market Redesign Order P 446, JA 2596.

Fundamentally, although acknowledging that "it is economically desirable for customers to be able to hedge uncertain costs," the Commission found that "the ability to hedge all costs is not a prerequisite for just and reasonable rates." Second Market Redesign Order P 42, JA 2448; *see also* Fourth Market Redesign Order P 100, JA 2433 (same); Second Market Redesign Order P 446, JA 2596 ("While we are sympathetic with the desire to hedge these losses, and have directed the [California ISO] to continue to work towards developing a marginal loss hedge, we do not find the lack of a marginal loss hedge to be unjust or unreasonable") (citing Order No. 681-A P 105).

Based on the same rationale, the Commission also reasonably rejected Sacramento's proposal that, "until the [California ISO] develops a marginal loss hedge, the Commission direct it to adopt a . . . transition mechanism, which would permit market participants to receive refunds so that they would not pay more than their average losses," Marginal Loss/Resource Adequacy Br. at 29 (quoting Fourth Market Redesign Order P 99, JA 3432). Fourth Market Redesign Order P 100, JA 3432.

Sacramento claims that the Commission acted inconsistently with *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163 (2004), when it rejected Sacramento's proposed "transitional" mechanism. Marginal Loss/Resource Adequacy Br. at 30-32. This claim is incorrect.

In *Midwest ISO*, the Commission determined that, "to give market participants more time to adjust to the [Locational Marginal Pricing] approach for setting prices and to develop confidence in market processes, [it would] permit surplus [marginal] loss revenues to be credited to those participants whose costs from marginal losses exceed the costs that would result from average loss pricing." *Midwest ISO*, 108 FERC ¶ 61,163 P 73; *see also Wis. Pub. Power*, 493 F.3d at 265 (same). "This transitional loss refund approach [was made] available to all existing transmission customers for a period of five years and to all new transmission customers for a period of one year from the start of the . . . markets." *Midwest ISO*, 108 FERC ¶ 61,163 P 73

Sacramento, by contrast, proposed a refund mechanism under which transmission customers would pay only average losses **until California ISO developed a marginal loss hedge**. Fourth Market Redesign Order P 99, JA 3432; R. 627, Sacramento Request For Rehearing of the Third Market Redesign Order, at 6, JA 3206. As the Commission explained, however, no Regional Transmission Organization or Independent System Operator had been able to develop a workable marginal loss hedge, and it was only theoretically possible that one could be designed. Third Market Redesign Order P 229, JA 3132 (citing Order No. 681-A P 105); *see also* Second Market Redesign Order PP 42, 446, JA 2448, 2596 (same).

In addition, *Midwest ISO* was issued in 2004. By the time Sacramento proposed its transitional marginal loss mechanism (in its 2007 Request for Rehearing of the Third Market Redesign Order), Locational Marginal Pricing mechanisms with marginal loss components already had been successfully implemented in other Regional Transmission Organizations' markets, including PJM, ISO-New England and New York ISO. First Market Redesign Order PP 25, 63, JA 1641, 1653 (citing cases listed, *supra* n.4). "While [it] underst[ood] certain parties' uneasiness with the pace of [market redesign] implementation, given the backdrop of the California energy crisis," the Commission determined that it would "not require additional phase-in of the market redesign, beyond that which it ha[d] already established." First Market Redesign Order P 25, JA 1641; *see also id.* PP 1381-82, JA 1990-91 (same); Second Market Redesign Order P 19, JA 2437 (same); First Market Redesign Order P 611, JA 1798 (approving Load Aggregation Point pricing, *i.e.*, average zonal marginal pricing, for load during the initial release of the Market Redesign as a transitional mechanism to minimize the impact of the Market Redesign on load).

Moreover, while customers will be charged marginal losses, they will receive credits for excess marginal loss revenues. Third Market Redesign Order P

247, JA 3139. Accordingly, the marginal loss charge will be dampened, and, in fact, might result in a financial outcome not substantially different from paying average loss charges. *Id.* This will not, however, undermine the economic benefits of marginal losses, as "rebating the over-collection to loads on a load-ratio share basis will not affect the relative loss costs of alternative supply sources. That is because a customer's rebate will be virtually the same regardless of its choice of supply sources,[8] so the difference in loss charges between supply sources will not be affected by the rebate." Second Market Redesign Order P 37, JA 2445.

Thus, although the Commission may not have referred specifically to *Midwest ISO*, the Commission adequately responded to Sacramento's *Midwest ISO*-based argument. *See Sacramento*, 474 F.3d at 803-04 (finding that, while FERC did not cite to a case proffered by Sacramento, it "adequately distinguished the principle [Sacramento] glean[ed] from" that case).

[8] "Any difference in revenue surplus associated with the choice among suppliers by a customer would be shared by all loads in the [California ISO], so the share of the difference in surplus retained by the customer would be very small." Second Market Redesign Order n.61, JA 2446.

E. The Commission Reasonably Determined That The Marginal Loss Proposal Appropriately Preserves Self-Supply, Consistent With Order No. 888

Sacramento contends that approving the marginal loss proposal violated Order No. 888's[9] determination that customers can self-supply their transmission losses. Marginal Loss/Resource Adequacy Br. at 32-34.[10] Again interpreting its own order, the Commission reasonably found otherwise. Second Market Redesign Order P 47, JA 2450.

FERC explained that entities will be able to "conservatively estimate[] losses, thus guaranteeing that they fully supply their losses." *Id.* "Accordingly," FERC determined, "this allows service consistent with Order No. 888 because the parties are provided flexibility to self-supply losses." Second Market Redesign Order P 47, JA 2450. Sacramento may interpret Order No. 888 to require more,

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[9] *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, FERC Stats. & Regs. ¶ 31,036, 61 Fed. Reg. 21,540 (1996), *clarified*, 76 FERC ¶ 61,009 and 76 FERC ¶ 61,347 (1996), *on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, 62 Fed. Reg. 12,274, *clarified*, 79 FERC ¶ 61,182 (1997), *on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248, 62 Fed. Reg. 64,688 (1997), *on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd, New York v. FERC*, 535 U.S. 1 (2002).

[10] While Sacramento's brief does not cite the portion of Order No. 888 upon which it relies, its Requests for Rehearing below (R. 251 at 10, JA 2079; R. 260 at 33, JA 2107) cite to Order No. 888-A at 30,237, which states that "supply of losses is

but the Commission's reasonable interpretation of its own order, not Sacramento's alternative interpretation, is due deference and should be upheld. *Wis. Pub. Power*, 493 F.3d at 266; *Entergy*, 375 F.3d at 1209.

Also, for the first time on appeal, Sacramento argues that "overestimating, *i.e.*, self-supplying *more* than its actual losses, could prove very costly." Marginal Loss/Resource Adequacy Br. at 34. As Sacramento acknowledges, however, if a transmission customer overestimates losses, it "would receive direct compensation through the energy payments for the excess generation at appropriate Locational prices." *Id.* (citing R. 30, Sacramento's Protest, at 45, JA 1168).

F. The Commission Reasonably Found That California ISO's Locational Marginal Pricing Mechanism Will Send More Accurate Price Signals

Imperial contends that the Locational Marginal Pricing Mechanism (including marginal loss charges) will not send market participants accurate price signals. Marginal Loss/Resource Adequacy Br. at 34-35. Instead, Imperial asserts, it will create rate uncertainty that, "rather than incenting investment in new transmission facilities at more cost-effective locations within the [California ISO], [will] actually discourage[] transmission owners, such as [Imperial], from investing

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purely a generation service that can be (1) self supplied; (2) purchased from the transmission provider, if it offers this service; or (3) purchased from a third party."

in facilities at any location *at all* in [California ISO]." Marginal Loss/Resource Adequacy Br. at 35; *see also id.* at 50-55.

To the contrary, as this Court has found, marginal loss pricing "sends more efficient signals to market participants . . . ." *Wis. Pub. Power*, 493 F.3d at 252. By "communicat[ing] the true market value of electricity at each location," the Locational Marginal Pricing proposal "will create financial incentives to dispatch the lowest cost energy," and "[i]n the long-term . . . help encourage transmission and generation investment at appropriate locations, as well as demand response." First Market Redesign Order P 10, JA 1632; *see also* Third Market Redesign Order P 254, JA 3143 ("[Locational Marginal Pricing] and marginal losses 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."). "These market design improvements will give investors greater confidence that their investments will be well-targeted to meet system needs and increase the likelihood that their investments will yield expected benefits." Third Market Redesign Order P 254, JA 3143; *see also* Second Market Redesign Order P 475, JA 2610 ("the assessment of marginal losses will provide a more accurate cost allocation mechanism than application of average losses, and can help entities better predict cost exposure when planning transmission expansion").

In addition, the Commission "disagree[d] with Imperial's claims that treatment of [transmission ownership rights] under [the market redesign] will create a disincentive for new transmission investments . . . ." Second Market Redesign Order P 475, JA 2609. New transmission ownership rights capacity additions will not be subject to congestion charges; transmission ownership rights transactions subject to marginal loss charges will be eligible for excess marginal loss revenue credits; and transmission ownership rights holders may be eligible for special transmission pricing incentives in accordance with the Commission's rulemaking in *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006). *Id.* "Consequently," the Commission found "that, overall, the treatment of [transmission ownership rights] under [the market redesign] should not deter investment in new transmission infrastructure." *Id.*

Imperial next asserts that "purchasers will not know the amount of [marginal loss] charges at the time service is requested and, therefore cannot possibly change a purchasing decision based on the amount of those charges," purportedly "defeat[ing] a central purpose of the FPA, requiring rates to be on file and noticed to the public, to enable purchasers to know in advance the consequences of the purchasing decisions they make." Marginal Loss/Resource Adequacy Br. at 35 and n.24 (internal quotation omitted). Imperial did not raise this assertion to the

Commission on rehearing, JA 2115, and, therefore, is jurisdictionally barred from raising it on appeal. FPA § 313(b), 16 U.S.C. § 825*l*(b) ("No objection to the 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 to do so."); *see also, e.g.*, *Pub. Serv. Comm'n of Wis. v. FERC*, 545 F.3d 1058, 1065 n.12 (D.C. Cir. 2008) (same).

As this Court has explained, "[e]nforcement of this provision, which [the Court] ha[s] considered to pose a jurisdictional bar, enables the Commission to correct its own errors, which might obviate judicial review, or to explain why in its expert judgment the party's objection is not well taken, which facilitates judicial review." *Save Our Sebasticook v. FERC*, 431 F.3d 379, 381 (D.C. Cir. 2005) (citations omitted); *see also Cal. Dep't of Water Res. v. FERC*, 306 F.3d 1121, 1125 (D.C. Cir. 2002); *Town of Norwood v. FERC*, 906 F.2d 772, 774-75 (D.C. Cir. 1990). Moreover, the "reasonable ground for failure" to raise an objection exception "is reserved for extraordinary situations," *Sebasticook*, 431 F.3d at 381-82 (citing *Wis. Power & Light Co. v. FERC*, 363 F.3d 453, 460 (D.C. Cir. 2004)), not present here.

In any event, contrary to Imperial's assertion, purchasers will know in advance the consequences of their purchasing decisions under California ISO's Locational Marginal Pricing mechanism. Each transmission will be subject to marginal losses determined “as if it were the last (marginal) transmission on the system,” *Wis. Pub. Power*, 493 F.3d at 252, and will receive an excess marginal loss revenue credit on a load-ratio share basis, First Market Redesign Order P 67, JA 1655; Second Market Redesign Order PP 37, 44, JA 2445, 2449.

G. The Commission Reasonably Approved California ISO’s Proposal To Allocate Excess Marginal Loss Revenues

There also is no merit to Imperial’s challenges to the mechanism the Commission approved to allocate excess marginal loss revenues. Marginal Loss/Resource Adequacy Br. at 36-38.

The Commission explained that “[i]t is a widely accepted principle of economics that prices in efficient, competitive markets reflect the marginal cost of producing and delivering the product or service to the customer” and, therefore, that 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.” Second Market Redesign Order P 44, JA 2445.

“Marginal cost includes the cost of marginal losses.” Second Market Redesign Order P 44, JA 2445. Because “it is a principle of mathematics that, whenever any variable is continuously increasing, the marginal value of the last unit exceeds the average of all units,” however, “marginal losses will always exceed average losses[,] and . . . more revenues will be collected from load than [must be paid] to generators to cover losses." First Market Redesign Order P 93, JA 1662 (citing *Atlantic City*, 115 FERC ¶ 61,132 at P 5).

California ISO proposed to credit the excess marginal loss revenues to all load on a load-ratio share basis; that is, on an hourly basis, California ISO would calculate a per-megawatt hour marginal loss credit to be applied to all load by dividing system-wide excess marginal loss revenues by system-wide megawatt hours of demand. R. 1, February 2006 Filing, Transmittal Letter 17-18, JA 134-35. The Commission found this proposal just and reasonable, as it ensures that load will pay the correct amount (marginal cost) for energy, and that all excess marginal loss revenues will be allocated in a manner that does not distort the marginal loss price signal. Second Market Redesign Order PP 37, 44, JA 2445, 2449.

Imperial complains that the crediting mechanism is inconsistent with cost causation principles, "lacks any rational nexus to specific ratepayers," and causes "some ratepayers [to] subsidize costs incurred to procure energy for losses occurring when [California ISO] is serving other ratepayers." Marginal Loss/Resource Adequacy Br. at 36-38. As this Court has found, however:

> the transmission losses occurring system-wide at any one time are caused by all the users on the system – are a function, that is, of the amount and direction of their aggregate demand. Therefore it is not irrational to conclude that each and every transmission user is equally responsible for all the transmission losses occurring on the system at any one time. In other words, . . . each customer is responsible for an indivisible portion of the transmission system losses imposed upon the

> system by the configuration of the group of customers using it at any one time."

Northern States Power Co. v. FERC, 30 F.3d 177, 182 (D.C. Cir. 1994). *See also Atlantic City*, 115 FERC ¶ 61,132 at P 5, cited First Market Redesign Order P 93, JA 1662 ("It is characteristic of the electric grid that marginal losses increase as the number of megawatts of power moved on the grid increases. . . . Since each customer contributes to the amount of power dispatched, each customer should pay equally for the marginal loss").

The "cost incurred to serve any customer (while serving all other customers) is the marginal cost of delivering electricity to the customer. Under cost causation principles," therefore, "no customer is entitled to a rebate below the marginal cost of serving that customer." Second Market Redesign Order P 44, JA 2449; *see also* First Market Redesign Order P 94, JA 1662 ("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") (citing *Atlantic City*, 115 FERC ¶ 61,132 at P 24); Second Market Redesign Order P 456, JA 2600 ("refunding to all customers on an average basis is equitable because the surplus created by the marginal loss mechanism results from the total service provided to all customers in the aggregate"). "In fact, in *Northeast Utilities*[, 105 FERC ¶ 61,122 at P 20, *reh'g* *denied*, 109 FERC ¶ 61,204 at P 21], the Commission made clear that the method for disbursing the amounts of any over collections should not directly reimburse customers for their marginal loss payments, as such a reimbursement would interfere with the goal of basing prices on marginal losses and would undermine price signals to investors and load." First Market Redesign Order P 94, JA 1662.

H. The Commission Appropriately Determined That Transmission Ownership Rights Transactions Involving Injections And/Or Withdrawals From California ISO's Transmission Grid Should Be Assessed Marginal Losses

"A [transmission ownership right] is the right to use transmission facilities that are located within the California ISO Control Area, but are either partially or wholly owned by an entity that is not a [Participating Transmission Owner, *i.e.*, a transmission owner that has turned over operational control of its facilities to California ISO]." Second Market Redesign Order n.376, JA 2584; First Market Redesign Order P 975, JA 1887. Imperial contends that marginal losses should not be applied to transactions involving transmission ownership rights. Marginal Loss/Resource Adequacy Br. at 38-49.

The Commission appropriately rejected Imperial's request for special transmission loss treatment for transmission ownership rights, finding that, "[e]ven though a [transmission ownership rights] holder might be using its own facilities and the [transmission ownership right] facilities are not part of the [California

ISO],” transmission ownership rights transactions **that “involve injections and withdrawals from the [California ISO] grid”** appropriately “are subject to marginal losses . . . .” Second Market Redesign Order P 458, JA 2601 (emphasis added); *see also id.* n.432, JA 2601 (“no marginal losses should apply to transactions where the [transmission ownership rights] holder has no point of interface with the [California ISO]”); R.298, Imperial Rehearing Request, at 10, JA 2124 (acknowledging that Imperial uses transmission ownership rights to “wheel energy . . . through the [California ISO] for purposes of serving [its] own load”). “While [transmission ownership rights] facilities are not part of the [California ISO]-controlled grid, they are interconnected with the [California ISO] grid and, therefore, influence power flows on [California ISO’s] grid.” Second Market Redesign Order at P 484, JA 2613; *see also id.* (assessing marginal losses to transmission ownership rights holders “is just and reasonable and consistent with cost causation”); *id.* at P 458, JA 2601 (transmission ownership rights facilities “are integrally connected to the California ISO grid”); R.298, Imperial Rehearing Request, at 39, JA 2153 (acknowledging that transmission ownership rights facilities are “physically located inside the [California ISO] Control Area,” and that “[California ISO] must have some involvement with [transmission ownership rights] for reliability reasons”).

The Commission found that, "[b]ecause marginal losses apply at the interface to the [California ISO] grid just as they would for any other import or export on the [California ISO] grid, the fact that the [transmission ownership right facility] is not a part of the [California ISO] grid is irrelevant." Second Market Redesign Order P 458, JA 2601. Thus, "the application of marginal losses to [transmission ownership rights] is no different from the application of marginal losses to other import and export schedules." *Id.*

Moreover, the Commission explained, "[t]reating marginal losses on a comparable basis for all grid users, including [transmission ownership rights], sends more accurate price signals, and promotes efficient dispatch." Second Market Redesign Order P 484, JA 2613; *see also id.* P 424, JA 2585 (applying marginal losses to transmission ownership rights will "improv[e] the efficiency of [California ISO's] market operations"). "[A]s much as possible,"[[11]] therefore, "losses should be treated on a consistent basis throughout the system, both to avoid

[11] Under the Market Redesign, California ISO will not assess marginal losses to transmission ownership rights if an existing transmission ownership rights agreement specifies marginal loss percentages. Second Market Redesign Order P 484, JA 2613; *see also* First Market Redesign Order P 1003, JA 1896(same); Second Market Redesign Order P 484, JA 2613 ("the [Market Redesign] Tariff does not abrogate [transmission ownership rights] contracts; Imperial's and other [transmission ownership rights] agreements with the [California ISO] remain in place").

discrimination among transmission customers, and to prevent distortion or bias in decisionmaking." Second Market Redesign Order P 475, JA 2610.

"As for Imperial's assertion [(Marginal Loss/Resource Adequacy Br. at 46)] that the Commission lacks jurisdiction to approve a tariff filing under FPA section 205 that dictates rates, terms or conditions of service applicable to a government utility's use of its own facilities," the Commission explained that it was "not authorizing the [California ISO] to charge Imperial for the use of its own facilities." Second Market Redesign Order P 485, JA 2614. "Rather, [the Commission was] allowing [California ISO] to charge Imperial for services [California ISO] is providing under the [Market Redesign] Tariff, and for use of [California ISO]-controlled facilities." *Id.* (citing, *e.g.*, *Mich. Elec. Trans. Co.*, 115 FERC ¶ 61,105 at PP 14-15 (2006) [12] (tariff charges appropriately assessed to governmental entities where they take service not only over facilities in which they have an ownership interest, but also over FERC-jurisdictional facilities)). *See Transmission Agency of N. Cal. v. FERC*, 495 F.3d 663, 671-72 (D.C. Cir. 2007) (FERC has authority pursuant to FPA § 205 to review non-jurisdictional municipality's revenue requirement, which was a component of California ISO's jurisdictional rate).

[12] The Commission's order inadvertently cites to an earlier order in that docket, *Mich. Elec. Trans. Co.*, 113 FERC ¶ 61,105 (2006).

As already noted, the Commission approved the assessment of marginal loss charges to transmission ownership rights holders only when their transmission ownership rights transactions "involve injections and withdrawals from the [California ISO] grid." Second Market Redesign Order P 458, JA 2601. Marginal losses will not apply to transactions where the transmission ownership rights holder has no point of interface with the California ISO. *Id.* n.432, JA 2601. Thus, Imperial's argument that the Commission failed to distinguish between transmission ownership rights holders' use of their own transmission grid from their use of California ISO's grid, Marginal Loss/Resource Adequacy Br. at 47-48, is baseless. If a transmission ownership rights holder's use of its transmission ownership rights does not involve injections or withdrawals from California ISO's grid, it will not be assessed marginal loss charges.

Likewise, California ISO will assess transmission ownership rights holders marginal losses based on the marginal cost of losses at the receipt point (*i.e.*, source) and delivery point (*i.e.*, sink) on California ISO's grid. Compliance Order P 309, JA 3008; First Market Redesign Order n.418, JA 1889. Thus, there is no basis for Imperial's concern, raised for the first time on appeal, that California ISO will assess marginal loss charges for the portion of the transmission that takes place on a transmission ownership rights holder's own facilities. Marginal Loss/Resource Adequacy Br. 49.

Furthermore, the Commission did not, contrary to Imperial's claim, conflate the burden of proof regarding California ISO's proposal to apply marginal losses to transmission ownership rights transactions. Marginal Loss/Resource Adequacy Br. at 55. As the Commission recognized, "[t]he initial burden of showing that the tariff proposal is just and reasonable is on the party making the FPA section 205 filing." Second Market Redesign Order P 14, JA 2435. "In the [First Market Redesign Order], the Commission found [California ISO]'s [Market Redesign] proposal to be just and reasonable." *Id.* Having done so, the Commission was not obligated to do more. *See City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984). Nevertheless, FERC examined Imperial's alternative proposal, and determined that "Imperial ha[d] not explained sufficiently why allowing individual [transmission ownership rights] holders to negotiate different loss provisions for new transmission capacity would not be unduly discriminatory with respect to other [transmission ownership rights] holders and transmission customers in general." *Id.* P 475, JA 2610. *See also id.* P 45, JA 2450 (explaining that once the Commission "reached its conclusion that the [California ISO]'s marginal loss proposal was just and reasonable . . . the Commission merely noted that no one had convinced it otherwise").

III. THE COMMISSION REASONABLY APPROVED CALIFORNIA ISO'S RESOURCE ADEQUACY PROPOSAL

California ISO "has the responsibility to ensure the reliability of the transmission system under its control." First Market Redesign Order P 1115, JA 1928. "[W]ithout an adequate resource adequacy program, the [California ISO] cannot fulfill that responsibility." *Id.*

To ensure the availability of an adequate supply of generation or demand responsive resources when and where needed to support safe and reliable operation of the grid, California ISO proposed to require load-serving entities to meet both overall system and local (*i.e.*, for constrained areas and load-pockets) resource adequacy requirements. First Market Redesign Order PP 1090, 1094, JA 1921, 1922. System resource adequacy requirements would be set by state and local regulatory authorities; if state and local regulatory authorities do not establish a system resource adequacy requirement, California ISO's default system requirement (based on a 15 percent planning reserve margin requirement) would apply. *Id.* P 1094, JA 1922; Second Market Redesign Order P 555, JA 2646.

The Commission found, however, "that the [California ISO] must play a greater role in setting local [resource adequacy] requirements because it is uniquely situated to assess needs in constrained areas and load pockets." First Market Redesign Order P 1119, JA 1930. Thus, California ISO "will perform an annual technical study to determine the minimum amount of capacity that must be available to the [California ISO] within each local capacity area," *i.e.*, each "area in which the transmission [capability] is insufficient to serve load and any flow-through of electricity, thereby requiring a minimum amount of generation capacity to be located within the area." First Market Redesign Order P 1156 and n.507, JA 1939; Second Market Redesign Order P 551, JA 2644. California ISO "will then work with Local Regulatory Authorities to set local capacity area requirements." First Market Redesign Order P 1119, JA 1930. "[R]esponsibility for local capacity area resources will be allocated to all [load-serving entities] in the local capacity area in accordance with the [load-serving entity]'s share of load." *Id.* P 1156, JA 1939; *see also* Second Market Redesign Order P 580, JA 2655 (same).

The Commission found the proposed "minimum resource adequacy requirements [to be] central to the reliable operation of the grid, critical to the proper functioning of centralized energy markets in California, and necessary to ensure that jurisdictional rates and services are just, reasonable and not unduly discriminatory." Second Market Redesign Order P 551, JA 2644. In fact, the Commission found that the "nexus between resource adequacy and the reliability and market functions of the [California ISO] could not be clearer or more significant." *Id.* P 552, JA 2644.

Not only can "one party's resource adequacy decisions . . . cause adverse reliability and cost[] impacts on other participants in a regionally operated system," but "resource adequacy is necessary to ensure that energy market bid caps effectively restrict the ability of sellers to exercise market power" without "result[ing] in insufficient generating capacity being added to meet the longer term capacity needs of customers." Second Market Redesign Order P 552, JA 2645. "Moreover, resource adequacy requirements ensure that one [load-serving entity] cannot 'lean on' the others to the detriment of their customers and grid reliability as a whole, thereby preventing undue discrimination." *Id.*; *see also* First Market Redesign Order P 1116, JA 1928 (same). The Commission further found that local resource adequacy requirements would ensure that California ISO "has sufficient resources in the appropriate locations to operate the transmission system." *Id.* P 1094, JA 1922.

San Francisco contends that it should be able to satisfy its local resource adequacy requirements by importing its existing transmission contract[13] and transmission ownership rights resources into a load pocket. Marginal

[13] Existing transmission contracts are contracts executed prior to California ISO's existence that grant transmission service rights over a participating transmission owner's facilities in accordance with the terms and conditions specified in the contract. First Market Redesign Order n.374, JA 1867; Second Market Redesign Order n.374, JA 2584.

Loss/Resource Adequacy Br. at 55-66. As the Commission explained, however, local resource adequacy requirements must be met by resources within a load pocket "to ensure reliability of the [California ISO]-controlled grid, because transmission capability available to import energy to meet load in the load pocket is limited." Second Market Redesign Order P 580, JA 2655; *see also id.* P 601, JA 2662 (same). In fact, each "local capacity area resource requirement is calculated as the amount of capacity that cannot be met with capacity outside the load pocket due to transmission limitations." Second Market Redesign Order P 580, JA 2655; *see also* First Market Redesign Order P 1156 and n.507, JA 1939 (same); Second Market Redesign Order P 601, JA 2662 ("[California ISO], in its annual technical study, will take into account a system's capability to reliably import power to serve local demand from remote generation in determining local capacity area resource requirements;" "Each [load-serving entity], through its respective Local Regulatory Authority, will have the opportunity to provide input in establishing the parameters, assumptions and other criteria to be used in the technical study"). "Accordingly," the Commission found, it would "not [be] reasonable to allow [a load-serving entity] to use the transmission capacity underlying its [existing transmission contract rights] to meet any of its local requirements with generation capacity imported from outside the load pocket." *Id.*

This does not diminish San Francisco's preexisting contract rights. Second Market Redesign Order P 602, JA 2662. "San Francisco retains the full rights of its [existing transmission contract] to transmit power from outside resources to meet[] its resource plans and use economic resources to optimize its portfolio."[14] *Id.*; *see also*, *e.g.*, First Market Redesign Order P 902, JA 1867 (California ISO will honor all existing transmission contract scheduling rights); *id.* P 905, JA 1869 (California ISO "will reserve transmission capacity equal to the existing rights transmission capacity and make a corresponding adjustment in its determination of [available transmission capacity]"); Compliance Order P 277, JA 2999 (California ISO "will reserve transmission capacity equal to the [transmission ownership rights] transmission capacity and make an adjustment to the applicable [available transmission capacity]"). The Commission simply determined that resources outside a load pocket cannot be used to satisfy local resource adequacy requirements. San Francisco does not claim that it has such a contractual right.

San Francisco also argues that "[t]he obligation to pay (now or later) for new [local resource adequacy] capacity effectively strands some of [San Francisco]'s existing capital investments" because the "Raker Act[, 38 Stat. 242 § 6 (1913),]

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[14] As a result, contrary to San Francisco's contention (which it raises for the first time on appeal, *see* R. 253, San Francisco's Rehearing Request, JA 2081), there was no need for the Commission to "satisfy the very high standard for contract modification . . . ." Marginal Loss/Resource Adequacy Br. at 66.

prohibits [San Francisco] from selling Hetch Hetchy generation to non-public entities for resale, so [San Francisco] has limited options for use of power displaced by the [local resource adequacy] capacity." Marginal Loss/Resource Adequacy Br. at 65 and n.120. San Francisco did not raise this argument on rehearing to the Commission, R. 253, JA 2081, and, therefore, is jurisdictionally barred from raising it on appeal. FPA § 313(b), 16 U.S.C. § 825*l*(b); *see also, e.g.*, *Pub. Serv. Comm'n of Wisconsin*, 545 F.3d at 1065 n.12.

Even if this argument were properly before the Court, it has no merit. Under the Raker Act, San Francisco is permitted to sell electric energy to any municipality, municipal water district, or irrigation district. 38 Stat. 242 § 6 ("the grantee is prohibited from ever selling or letting to any corporation or individual, except a municipality or a municipal water district or irrigation district"); *see also* Compliance Order P 35, JA 2926 (finding that marginal loss charges would apply to San Francisco because the transmission of energy it sells to irrigation districts and municipalities under the Raker Act will likely generate losses). Thus, there is no basis for San Francisco's claim that its existing capital investments would be "stranded" as a result of the local resource adequacy requirement.

IV. THE COMMISSION'S REVIEW OF CALIFORNIA ISO'S CONGESTION REVENUE RIGHTS PROPOSAL WAS LEGALLY AND FACTUALLY SOUND

A. The Commission Reasonably Approved California ISO's Proposed Historical Reference Period

In accepting California ISO's proposed historical reference period for Congestion Revenue Rights allocation, the Commission determined that the 2006 historical period met the guidelines that govern its review of such proposals. First, the Commission observed, "the historical reference period chosen should be reasonably representative of the period during which the rates will be in effect." Third Market Redesign Order P 155 & n.91, JA 3104 (citing, *e.g.*, *Blue Ridge Power Agency*, 55 FERC ¶ 61,509 at 62,787 (1991)).

Second, the agency emphasized that relying on "a prior time period before market participants had notice that this 'snapshot' would be used for [Congestion Revenue Rights] allocation will ensure that parties do not strategically alter their supply decisions," thus preventing participants from "cherry-picking of the most valuable long-term [Congestion Revenue Rights]." *Id.* & n.92 (citing January 2007 Filing, Exh. No. ISO-2 (Dr. Pope's testimony) at 32-33, JA 2286-87).

Third, it was necessary for the designated time period to be "sufficiently close to the start of the [Market Redesign] that the data are not stale." *Id.* & n.93 (citing, *e.g.*, 18 C.F.R. § 35.13 (d)(4); *Blue Ridge*, 55 FERC at 62,787).

The Commission concluded that California ISO's "proposed 2006 historical period accomplishes these goals." Fourth Market Redesign Order P 29, JA 3405; *see also* Third Market Redesign Order P 156, JA 3105 (holding that California ISO's proposed period "better meets" the relevant criteria than alternate proposals, and "addresses stakeholders' concerns").[15] The designated period was "reasonably representative of the period during which the rates will be in effect," as "recent history is a reasonable indicator of the congestion charges that [load-serving entities] will incur" during the first year of Market Redesign operation. *Id.* (footnote omitted). Additionally, the period chosen was "far enough ahead of [Market Redesign] so that parties cannot change their procurement decisions, which have already been made, to obtain valuable [Congestion Revenue Rights]." *Id.*

This Court has firmly established that "FERC has wide discretion to determine where to draw administrative lines." *ExxonMobil Gas Marketing Co. v. FERC*, 297 F.3d 1071, 1085 (D.C. Cir. 2002) (quoting *AT&T Corp. v. FCC*, 220 F.3d 607, 627 (D.C. Cir. 2000) (internal quotation marks omitted)). In such a case, the Court has explained, it is "generally 'unwilling to review line-drawing

[15] The initial proposed period of September 1, 2004 through August 31, 2005 was changed because implementation of the Market Redesign was postponed. *See* Third Market Redesign Order P 156, JA 3105.

performed by the Commission unless a petitioner can demonstrate that lines drawn . . . are patently unreasonable, having no relationship to the underlying regulatory problem.'" *ExxonMobil*, 297 F.3d at 1085 (quoting *Cassell v. FCC*, 154 F.3d 478, 485 (D.C. Cir. 1998) and *Home Box Office, Inc. v. FCC*, 567 F.2d 9, 60 (D.C. Cir. 1977)). Thus, the burden is on the petitioner to show that the agency's "chosen line of demarcation is not within a zone of reasonableness as distinct from the question of whether the line drawn by the Commission is precisely right." *Pub. Serv. Comm'n of Wisconsin*, 545 F.3d at 1062 (quoting *ExxonMobil*, 297 F.3d at 1084) (internal quotation marks omitted).

San Diego cannot meet its burden to demonstrate that the Commission's approval of California ISO's proposed 2006 historical reference period was unreasonable. San Diego's challenge is predicated on the agency's alleged failure to "address [San Diego's] unique situation" which, it asserts, will cause it a disadvantage in the Congestion Revenue Rights allocation if the 2006 historical reference period applies. Congestion Revenue Rights Br. at 26.

To accommodate its purportedly unique situation, San Diego proposed two modifications to the 2006 reference period submitted by California ISO. *See* Congestion Revenue Rights Br. at 17 (citing San Diego Protest at 23-28, JA 2825-28).

First, San Diego argued that the definition of resource verification in 2006 should be expanded to include previously signed contracts. As the Commission observed, however, California ISO had considered this alternative "but found that changing the nature of the historical reference period to allow contracts for future delivery to count would be unworkable." Third Market Redesign Order P 152, JA 3103. Any such change, the ISO further maintained, if extended into the future sufficiently to give the benefit sought by San Diego, would create "difficult complexities" of administration, as well as a further delay in the "[Congestion Revenue Rights] implementation schedule." *Id.*

San Diego's other proposal was that resource-based priorities in the initial allocation of Congestion Revenue Rights be limited to the term of the underlying contracts. *See* Third Market Redesign Order P 146, JA 3101. As California ISO pointed out, however, based on Dr. Kristov's testimony, any "ongoing source verification" for the underlying contracts beyond the first year of Market Redesign operation would "carry with it inefficient contracting incentives and additional administrative complexity." *Id.* at P 153 & n.90, JA 3103 (citing R. 586, California ISO June 14, 2007 Answer, at 24, JA 2870 (citing R. 545, California ISO May 7, 2007 Filing, at Exh. ISO-1 (Dr. Kristov testimony) at 63, JA 2794)).

After considering all of this, the Commission determined that San Diego's requested modifications were unnecessary. Third Market Redesign Order P 157, JA 3105. Rather, "[San Diego's] concerns are best addressed by ensuring flexibility for [load-serving entities] to obtain the appropriate [Congestion Revenue Rights] in future years, rather than by changing or distorting the historical reference period." *Id.* "To that end," the agency explained, it directed the ISO to lower the "adjusted load metric[, *i.e.*, the amount of load] that can be nominated for long-term [Congestion Revenue Rights]." *Id.*

The Commission elaborated on its decision on rehearing. There, the agency emphasized certain elements of California ISO's Congestion Revenue Rights rate design that should help load-serving entities, including San Diego, obtain adequate Congestion Revenue Rights. First, California ISO's proposed mechanism affords load-serving entities "the flexibility to nominate non-source verified [Congestion Revenue Rights] in free-choice tiers." Fourth Market Redesign Order P 32, JA 3407; *see also id.* P 28, JA 3405. "These free-choice [Congestion Revenue Rights] nominations," the Commission indicated, should "provide load-serving entities with access to [Congestion Revenue Rights] to hedge congestion costs associated with resources procured after the historical reference period." *Id.* P 28, JA 3405.

Additionally, an "important design element" of the Congestion Revenue Rights mechanism was the Priority Nomination Process, which replaces source verification after the first year of Market Redesign operation. Fourth Market

Redesign Order P 28, JA 3405. This process enables load-serving entities to retain Congestion Revenue Rights obtained in the free-choice tier. *Id.*

The Commission further noted that its requirement that California ISO lower the amount of long-term Congestion Revenue Rights capacity eligible for nomination "helps ensure that grid capacity for short-term [Congestion Revenue Rights] nominations will remain available as market participants gain experience under [Market Redesign]." Fourth Market Redesign Order P 28, JA 3405; *see also id.* at P 32, JA 3407 ("The Commission's action, phasing in long-term [Congestion Revenue Rights] eligibility over a multi-year period, . . . helps to ensure that market participants do not unnecessarily 'lock-up a significant portion of grid capacity as long-term [Congestion Revenue Rights] in year one, reducing flexibility for [load-serving entities] in later years'") (quoting First Market Redesign Order P 136, JA 1645)).

Moreover, the Commission pointed out, allocated Congestion Revenue Rights may be transferred to other market participants through California ISO auctions or bilateral contracts. *Id.* at P 34, JA 3408; Third Market Redesign Order P 96 & n.62, JA 3085 (market participants can "sell[] portions of their allocated long-term [Congestion Revenue Rights] in the annual auction process in the second year of [Market Redesign], and thereafter;" "In year-one, market participants wishing to sell a portion of their long-term [Congestion Revenue Rights] will have to do so bilaterally").

Based on this analysis, the Commission concluded that it "disagree[d] with [San Diego] that further action limiting [load-serving entities'] ability to retain source-verified short-term [Congestion Revenue Rights] is warranted." Fourth Market Redesign Order P 32, JA 3407. Rather, the agency concluded, "the balance struck between providing [load-serving 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 is reasonable." *Id.* "This flexibility coupled with the increased certainty provided by the Priority Nomination Process are important design features that [the Commission] [was] not inclined to modify." *Id.* at P 31, JA 3407; *see also id.* at P 32, JA 3407 ("modifying the Priority Nomination Process to purge the initial source verifications upon the expiration of the underlying contract may upset this balance").

Furthermore, the Commission noted that, to the extent San Diego's argument was based on its anomalous position in 2006, changing the period to include the first quarter of 2007 (which the Commission subsequently approved, *Cal. Indep. Sys. Operator Corp.*, 124 FERC ¶ 61,107 PP 83-84 (2008)) "could further alleviate [San Diego's] concerns that its transmission usage for imports was unusually low in 2006." Fourth Market Redesign Order P 30 n.31, JA 3406.

Thus, the Commission fully considered San Diego's claims, but was "not persuaded" that it "faces unique circumstances that warrant modification" of this intrinsic element of California ISO's Congestion Revenue Rights rate design. Fourth Market Redesign Order P 33, JA 3407; *see also id.* (San Diego "fails to demonstrate that [California ISO's] proposal must be modified in order to prevent unduly discriminatory outcomes"). In sum, the Commission reasonably found that San Diego had not met its burden to demonstrate that the administrative line drawn here – the 2006 historical reference period – was unreasonable.

Before the Court, San Diego argues that the Commission erred by failing to provide it with an effective remedy "to ensure that [it] and its ratepayers are not subject to unjust and unreasonable rates or to undue discrimination compared with other [load-serving entities]." Congestion Revenue Rights Br. 25, 26-31. As discussed above, the Commission fully analyzed San Diego's speculative contentions and found that California ISO's allocation process was just and reasonable and not unduly discriminatory. Thus, the Commission reasonably concluded that San Diego's speculation about its future allocation position did not, at that time, warrant modifying California ISO's Congestion Revenue Rights system.

The Commission did, however, remind San Diego that, in the event problems did arise in the implementation of the ISO's Congestion Revenue Rights process, under section 206 of the FPA the agency "has the right to institute an investigation and order appropriate changes." Fourth Market Redesign Order P 34 n.36, JA 3408 (citing 16 U.S.C. § 824e). And, of course, San Diego itself can seek relief under that section if it can allege an actual injury resulting from the Congestion Revenue Rights process. While San Diego complains that the prospective nature of the section 206 remedy makes it "unclear whether [it] could be made whole through such a remedy once [Congestion Revenue Rights] have been allocated to others" (Congestion Revenue Rights Br. at 31 n.20), that is a complaint for Congress (which enacted FPA § 206 essentially as a prospective measure), not FERC. In any event, unless and until San Diego seeks relief from the actual operation of the Congestion Revenue Rights system, the matter is wholly speculative.

It is "well settled" that this Court will "defer to [the Commission's] decisions in remedial matters." *Constellation Energy Commodities Group, Inc. v. FERC*, 457 F.3d 14, 22-23 (D.C. Cir. 2006) (quoting *Koch Gateway Pipeline Co. v. FERC*, 136 F.3d 810, 816 (D.C. Cir. 1998) (internal quotation marks omitted); *see also Consolidated Edison Co. v. FERC*, 510 F.3d 333, 339 (D.C. Cir. 2007) (the Court's review "is particularly deferential when a challenge 'relates to the fashioning of remedies' where '[a]gency discretion is often at its zenith.'") (quoting *Towns of Concord v. FERC*, 955 F.2d 67, 76 (D.C. Cir. 1992) (additional citations omitted). In the circumstances presented, San Diego cannot demonstrate that the Commission's decision not to grant it special treatment was an abuse of the agency's remedial discretion.

San Diego presents two other legal challenges to the Commission's approval of the 2006 historical period for Congestion Revenue Right source verification. Neither one, however, withstands scrutiny.

First, San Diego maintains that the Commission's failure to provide San Diego specific relief from its alleged disadvantage "is inconsistent with FPA Section 217(b)(4)," which requires the Commission to ensure that load-serving entities can secure sufficient long-term transmission rights (*see* p. 9, *supra*). Congestion Revenue Rights Br. 34. The Commission disagreed, finding that California ISO's proposal was fully consistent with that provision because it included "adequate safety features, *i.e.*, the ability to nominate short-term [Congestion Revenue Rights] in the free-choice tiers and the ability to trade allocated [Congestion Revenue Rights]," to meet the statutory goal. Fourth Market Redesign Order P 34 & n.35, JA 3408.

Second, San Diego argues that the Commission's decision failed to distinguish precedent in which it had afforded relief to utilities that faced similar disadvantages from restructuring measures. Congestion Revenue Rights Br. 31. In this regard, San Diego spends several pages in its brief on its theory why remedies provided by the Commission for certain problems in different organized markets required the agency to impose the remedies San Diego sought here. *Id.* 31-34 (citing *Southwest Power Pool*, 116 FERC ¶ 61,162 (2006); *Midwest ISO*, 108 FERC ¶ 61,163 at P 90; *New England Power Pool*, 101 FERC ¶ 61,334 P 36). In its request for rehearing before the Commission, by contrast, San Diego made this argument in two sentences and cited these cases, without any discussion, in a footnote. *See* Request for Rehearing of San Diego at 16 & n.33, JA 3223.

The Commission appropriately answered San Diego's contention. As the Commission found, "San Diego fail[ed] to provide evidence" indicating that any special ameliorative measures were necessary in view of the "adequate safety features" built into the Congestion Revenue Rights process to protect load-serving entities and their ratepayers. Fourth Market Redesign Order P 33, JA 3407. Thus, the Commission reasonably viewed the cited precedent as irrelevant here.

B. The Commission Reasonably Determined That Obligation Congestion Revenue Rights Met The Appropriate Legal Standard

The Commission held that California's ISO proposal to offer only Congestion Revenue Rights obligations, as opposed to options, was not only a "reasonable" "hedging tool against congestion in the day-ahead market," but also the preferable rate design. *See* Second Market Redesign Order P 407, JA 2577. "The advantage of obligations over options," the Commission determined, "is that [Congestion Revenue Rights] obligations allow [California ISO] to award a larger number" of such rights "in both [megawatt] and dollar terms" than if load-serving entities were awarded only Congestion Revenue Rights options. *Id.* This was because, the agency explained, obligation Congestion Revenue Rights would provide "counterflow that relieves otherwise binding [transmission] constraints . . . while [Congestion Revenue Rights] defined as options do not provide such counterflow." *Id.* & n.348, JA 2577 (citing January 2007 Filing, Ex. ISO-2 (Dr. Pope testimony) at 19-21 (JA 2273-75)). Thus, obligation Congestion Revenue Rights provide an "expanded ability to hedge against congestion." Second Market Redesign Order P 407, JA 2577.

The Commission acknowledged that an obligation Congestion Revenue Right "requires the holder to pay [locational marginal] price differences if the prices at the source point(s) in the transmission right are higher than those at the sink [*i.e.*, withdrawal] point(s)" on the transmission system, while an option Congestion Revenue Right does not. Third Market Redesign Order P 223, JA 3129. However, the Commission determined, this risk was limited by the fact that, assuming "the holder of the obligation right can follow the schedule implied in its transmission right (*i.e.*, the [megawatts] injected and withdrawn)," it would collect negative congestion charges – payments by California ISO – of the amount it owes in Congestion Revenue Rights obligation payments. *Id.* In this regard, the Commission indicated that, under California ISO's proposal, "the availability of seasonal and time-of-use [Congestion Revenue Rights] helps to reduce the potential for obligation payments" because "a party that submits a physical schedule that matches its obligation [Congestion Revenue Right] will face little risk of negative payments." *Id.* P 226, JA 3130.

Finally, the Commission found that California ISO's proposal to offer only obligation long-term Congestion Revenue Rights satisfied the requirements of Order No. 681. Third Market Redesign Order P 226, JA 3130. Indeed, the Commission found in Order No. 681 that obligation Congestion Revenue Rights would make available more congestion relief to market participants, while "allocation of [long term transmission] option rights would present equity problems in most organized electricity markets." *Id.* & n.144, JA 3130 (citing

Order No. 681 P 475) (option rights would greatly reduce the set of allocated rights available to market participants). Moreover, no commenters in the rulemaking proceeding (including Sacramento) had requested the allocation of long-term option rights, while some even "warned against allowing" such rights. Order No. 681 P 475; *see also id.* P 471 (commenters were concerned that option rights "encumber too much transmission capacity, resulting in a reduction in the quantity of rights available").

In sum, the Commission gave a full and rational explanation for its approval of the California ISO's proposal solely to offer obligation-type Congestion Revenue Rights. Having done so, the agency's decision warrants this Court's deference and should be sustained. *See, e.g.*, *Entergy Services, Inc. v. FERC*, 319 F.3d 536, 541 (D.C. Cir. 2003) (citing *Sithe/Independence Power Partners*, 165 F.3d 944, 958 (D.C. Cir. 1999)) ("in light of the technical nature of rate design, involving policy judgments at the core of the regulatory function," review of the Commission's ratemaking determinations is "highly deferential").

Sacramento argues that the Commission failed to address its objection that "obligation-only [Congestion Revenue Rights] were not equivalent, much less superior, to firm service" under the *pro forma* Open Access Transmission Tariff, "because, unlike customers purchasing firm service" under the Tariff, "holders of obligation [Congestion Revenue Rights] remain[] at risk of incurring unpredictable congestion charges." Congestion Revenue Rights Br. 38.

However, as Sacramento acknowledges, the Fourth Market Redesign Order specifically pointed out that the Commission previously "found that financial rights in the form of obligation long-term [Congestion Revenue Rights] are equivalent to physical rights." Congestion Revenue Rights Br. 38 (quoting Fourth Market Redesign Order P 92, JA 3429). Sacramento faults this statement as insufficient, but fails to acknowledge the footnote citing precedent supporting the Commission's statement. *Id.* P 92 n.93, JA 3429 (citing Order No. 681 PP 170, 473-74; *Midwest ISO*, 109 FERC ¶ 61,157 P 140; *Pacific Gas & Elec., et al.*, 80 FERC ¶ 61,128 at 61,427 & n.40 (1997)).

Thus, in the cited section of Order No. 681, the Commission explained that it had interpreted FPA section 217(b)(4) "to require that load serving entities be able to obtain long-term firm rights, whether as physical rights or as equivalent financial rights." Order No. 681 P 473. Essentially, the agency observed, it would consider physical or financial rights as equivalent, because "we have sought to provide guarantees of financial 'firmness' alongside the existing physical firmness of transmission scheduling in the organized electricity markets," *i.e.*, decreased physical curtailment. *Id.* P 474. Therefore, the Commission appropriately responded to Sacramento's contention.

Sacramento also attacks the Commission's conclusion that holders of obligation Congestion Revenue Rights run "little risk of negative payments." Fourth Market Redesign Order P 94, JA 3430. In this regard, Sacramento first contends that "there is no support in the record for this conclusion." Congestion Revenue Rights Br. 41.

Sacramento's argument takes obligation Congestion Revenue Rights completely out of their regulatory context. Transmission customers will not be acquiring these rights in a vacuum, but to meet their scheduling requirements on the transmission system. Thus, the Commission explained, the basis of its risk assessment was the relationship between a party's Congestion Revenue Right and its actual transmission scheduling: "A party that submits a physical schedule matching its obligation [Congestion Revenue Right] should face little risk of negative payments." Fourth Market Redesign Order P 94, JA 3430; *see also* Third Market Redesign Order P 226, JA 3130 ("the availability of seasonal and time-of-use [Congestion Revenue Rights]" will "reduce potential for obligation payments, as will a party's submission of physical schedule that conforms to its obligation).

The Commission's conclusion was specifically supported by Dr. Pope's testimony on behalf of California ISO. As she explained:

> A [Congestion Revenue Right] obligation can provide a perfect congestion hedge even in the circumstance in which the [Congestion Revenue Right] obligation entails a payment by the [Congestion

> Revenue Right] Holder, because the transaction hedged by that [Congestion Revenue Right] would receive an offsetting congestion payment for providing counterflow so that the net congestion charge would still be zero. Under [Locational Marginal Pricing], a transmission schedule from a high priced location to a low priced location is paid for providing counterflow rather than being charged for congestion.

January 2007 Filing, Exh. No. ISO-2 at 20, JA 2274. *See* Second Market Redesign Order P 407, JA 2577.

Alternatively, Sacramento complains, "[e]ven if the *likelihood* of a negative payment obligation were small . . . the *size* of such a potential obligation might be enormous" due to the "'highly volatile' and inherently 'unpredictable' nature of congestion patterns" that FERC itself recognized. Congestion Revenue Rights Br. 41 (quoting First Market Redesign Order P 10, JA 1633).

Sacramento's assertion, however, is based on a misreading of the indicated language. The Commission's reference to the "highly volatile and "unpredictable" nature of congestion costs described the situation under the California ISO's *previous* rate design, which Market Redesign replaced. First Market Redesign Order P 10, JA 1633. On the contrary, the agency concluded, the new Market Redesign system "largely alleviates this problem by ensuring that all congestion costs are reflected in market prices and by issuing" Congestion Revenue Rights, "a better form of financial transmission rights." *Id.*

In this Court, "[i]t is well established that an agency's predictive judgments about areas that are within the agency's field of discretion and expertise are entitled to particularly deferential review, as long as they are reasonable." *Wis. Pub. Power*, 493 F.3d at 260 (internal quotation marks omitted) (quoting *EarthLink, Inc. v. FCC*, 462 F.3d 1, 12 (D.C. Cir. 2006), and citing *Envtl. Action, Inc. v. FERC*, 939 F.2d 1057, 1064 (D.C. Cir. 1991)). Because the Commission reasonably explained its rejection of Sacramento's scenario of high costs stemming from obligation Congestion Revenue Rights, the Court should sustain the agency's decision.

CONCLUSION

For the reasons stated, the Commission's orders should be affirmed in all respects.

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December 7, 2009

Sacramento Municipal Utility District, *et al.*, v. FERC
D.C. Cir. No. 07-1208, *et al*.

CERTIFICATE OF COMPLIANCE

In accordance with Fed. R. App. P. 32(a)(7)(C)(i), I certify that the Brief of Respondent Federal Energy Regulatory Commission contains 16,398 words, not including the tables of contents and authorities, the certificates of counsel, or the addendum.

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December 7, 2009

ADDENDUM

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AND
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Section 205 of the Federal Power Act, 16 U.S.C. § 824d, provides as follows:

(a) All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

(b) No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Unless the Commission otherwise orders, no change shall be made by any public utility in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Whenever any such new schedule is filed the Commission shall have authority, either upon complaint or upon its own initiative without complaint, at once, and, if it so orders, without answer or formal pleading by the public utility, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the public utility affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of such five months, the proposed change of rate, charge, classification, or service shall go into effect at the end of such period, but in case of a proposed increased rate or charge, the Commission may by order require the interested public utility or public utilities to keep accurate account in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts are paid, and upon completion of the hearing and decision may by further order require such public utility or public utilities to refund, with interest, to the persons in whose behalf such amounts were paid, such portion of such increased rates or charges as by its decision shall be found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

(f)(1) Not later than 2 years after November 9, 1978, and not less often than every 4 years thereafter, the Commission shall make a thorough review of automatic adjustment clauses in public utility rate schedules to examine—

(A) whether or not each such clause effectively provides incentives for efficient use of resources (including economical purchase and use of fuel and electric energy), and

(B) whether any such clause reflects any costs other than costs which are—

(i) subject to periodic fluctuations and

(ii) not susceptible to precise determinations in rate cases prior to the time such costs are incurred.

Such review may take place in individual rate proceedings or in generic or other separate proceedings applicable to one or more utilities.

(2) Not less frequently than every 2 years, in rate proceedings or in generic or other separate proceedings, the Commission shall review, with respect to each public utility, practices under any automatic adjustment clauses of such utility to insure efficient use of resources (including economical purchase and use of fuel and electric energy) under such clauses.

(3) The Commission may, on its own motion or upon complaint, after an opportunity for an evidentiary hearing, order a public utility to—

(A) modify the terms and provisions of any automatic adjustment clause, or

(B) cease any practice in connection with the clause, if such clause or practice does not result in the economical purchase and use of fuel, electric energy, or other items, the cost of which is included in any rate schedule under an automatic adjustment clause.

(4) As used in this subsection, the term "automatic adjustment clause" means a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate.

Section 206 of the Federal Power Act, 16 U.S.C. § 824e, provides as follows:

(a) Whenever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. Any complaint or motion of the Commission to initiate a proceeding under this section shall state the change or changes to be made in the rate, charge, classification, rule, regulation, practice, or contract then in force, and the reasons for any proposed change or changes therein. If, after review of any motion or complaint and answer, the Commission shall decide to hold a hearing, it shall fix by order the time and place of such hearing and shall specify the issues to be adjudicated.

(b) Whenever the Commission institutes a proceeding under this section, the Commission shall establish a refund effective date. In the case of a proceeding instituted on complaint, the refund effective date shall not be earlier than the date of the filing of such complaint nor later than 5 months after the filing of such complaint. In the case of a proceeding instituted by the Commission on its own motion, the refund effective date shall not be earlier than the date of the publication by the Commission of notice of its intention to initiate such proceeding nor later than 5 months after the publication date. Upon institution of a proceeding under this section, the Commission shall give to the decision of such proceeding the same preference as provided under section 824d of this title and otherwise act as speedily as possible. If no final decision is rendered by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to this section, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision. In any proceeding under this section, the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon the Commission or the complainant. At the conclusion of any proceeding under this section, the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force: Provided, That if the proceeding is not concluded within fifteen months after the refund effective date and if the Commission determines at the conclusion of the proceeding that the proceeding was not resolved within the fifteen-month period primarily because of dilatory behavior by the public utility, the Commission may order refunds of any or all amounts paid for the period subsequent to the refund effective date and prior to the conclusion of the proceeding. The refunds shall be made, with interest, to those persons who have paid those rates or charges which are the subject of the proceeding.

(c) Notwithstanding subsection (b) of this section, in a proceeding commenced under this section involving two or more electric utility companies of a registered holding company, refunds which might otherwise be payable under subsection (b) of this section shall not be ordered to the extent that such refunds would result from any portion of a Commission order that (1) requires a decrease in system production or transmission costs to be paid by one or more of such electric companies; and (2) is based upon a determination that the amount of such decrease should be paid through an increase in the costs to be paid by other electric utility companies of such registered holding company: Provided, That refunds, in whole or in part, may be ordered by the Commission if it determines that the registered holding company would not experience any reduction in revenues which results from an inability of an electric utility company of the holding company to recover such increase in costs for the period between the refund effective date and the effective date of the Commission's order. For purposes of this subsection, the terms "electric utility companies" and "registered holding company" shall have the same meanings as provided in the Public Utility Holding Company Act of 1935, as amended.

(d) The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy.

(e) Short-term sales

(1) In this subsection:

(A) The term “short-term sale” means an agreement for the sale of electric energy at wholesale in interstate commerce that is for a period of 31 days or less (excluding monthly contracts subject to automatic renewal).

(B) The term “applicable Commission rule” means a Commission rule applicable to sales at wholesale by public utilities that the Commission determines after notice and comment should also be applicable to entities subject to this subsection.

(2) If an entity described in section 824 (f) of this title voluntarily makes a short-term sale of electric energy through an organized market in which the rates for the sale are established by Commission-approved tariff (rather than by contract) and the sale violates the terms of the tariff or applicable Commission rules in effect at the time of the sale, the entity shall be subject to the refund authority of the Commission under this section with respect to the violation.

(3) This section shall not apply to—

(A) any entity that sells in total (including affiliates of the entity) less than 8,000,000 megawatt hours of electricity per year; or

(B) an electric cooperative.

(4)(A) The Commission shall have refund authority under paragraph (2) with respect to a voluntary short term sale of electric energy by the Bonneville Power Administration only if the sale is at an unjust and unreasonable rate.

(B) The Commission may order a refund under subparagraph (A) only for short-term sales made by the Bonneville Power Administration at rates that are higher than the highest just and reasonable rate charged by any other entity for a short-term sale of electric energy in the same geographic market for the same, or most nearly comparable, period as the sale by the Bonneville Power Administration.

(C) In the case of any Federal power marketing agency or the Tennessee Valley Authority, the Commission shall not assert or exercise any regulatory authority or power under paragraph (2) other than the ordering of refunds to achieve a just and reasonable rate.

Section 217(b) of the Federal Power Act, 16 U.S.C. § 824q(b), provides as follows:

(b)(1) Paragraph (2) applies to any load-serving entity that, as of August 8, 2005—

(A) owns generation facilities, markets the output of Federal generation facilities, or holds rights under one or more wholesale contracts to purchase electric energy, for the purpose of meeting a service obligation; and

(B) by reason of ownership of transmission facilities, or one or more contracts or service agreements for firm transmission service, holds firm transmission rights for delivery of the output of the generation facilities or the purchased energy to meet the service obligation.

(2) Any load-serving entity described in paragraph (1) is entitled to use the firm transmission rights, or, equivalent tradable or financial transmission rights, in order to deliver the output or purchased energy, or the output of other generating facilities or purchased energy to the extent deliverable using the rights, to the extent required to meet the service obligation of the load-serving entity.

(3)(A) To the extent that all or a portion of the service obligation covered by the firm transmission rights or equivalent tradable or financial transmission rights is transferred to another load-serving entity, the successor load-serving entity shall be entitled to use the firm transmission rights or equivalent tradable or financial transmission rights associated with the transferred service obligation.

(B) Subsequent transfers to another load-serving entity, or back to the original load-serving entity, shall be entitled to the same rights.

(4) The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.

Section 313(b) of the Federal Power Act, 16 U.S.C. § 825*l*(b), provides as follows:

(b) Any party to a proceeding under this chapter aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the United States court of appeals for any circuit wherein the licensee or public utility to which the order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part. A copy of such petition shall forthwith be transmitted by the clerk of the court to any member of the Commission and thereupon the Commission shall file with the court the record upon which the order complained of was entered, as provided in section 2112 of title 28. Upon the filing of such petition such court shall have jurisdiction, which upon the filing of the record with it shall be exclusive, to affirm, modify, or set aside such order in whole or in part. No objection to the 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. The finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive. If any party shall apply to the court for leave to adduce additional evidence, and shall show to the satisfaction of the court that such additional evidence is material and that there were reasonable grounds for failure to adduce such evidence in the proceedings before the Commission, the court may order such additional evidence to be taken before the Commission and to be adduced upon the hearing in such manner and upon such terms and conditions as to the court may seem proper. The Commission may modify its findings as to the facts by reason of the additional evidence so taken, and it shall file with the court such modified or new findings which, if supported by substantial evidence, shall be conclusive, and its recommendation, if any, for the modification or setting aside of the original order. The judgment and decree of the court, affirming, modifying, or setting aside, in whole or in part, any such order of the Commission, shall be final, subject to review by the Supreme Court of the United States upon certiorari or certification as provided in section 1254 of title 28.

The Raker Act, 38 Stat. 242 § 6 provides as follows:

Sec. 6. That the grantee is prohibited from ever selling or letting to any corporation or individual, except a municipality or a municipal water district or irrigation district, the right to sell or sublet the water or the electric energy sold or given to it or him by the said grantee: *Provided*, That the rights hereby granted shall not be sold, assigned, or transferred to any private person, corporation, or association, and in case of any attempt to so sell, assign, transfer, or convey, this grant shall revert to the Government of the United States.

18 C.F.R. § 35.13(d)(4) provides as follows:

Sec. 35.13 Filing of changes in rate schedules.

(d) Cost of service information—

(4) Test period. If Period II data are not submitted for Statements AA through BM, Period I shall be the test period. If Period II data are submitted for Statements AA through BM, Period II shall be the test period.

18 C.F.R. § 42.1(c)(1)(i)-(ii) provides as follows:

(c) General rule. (1) Every public utility that is a transmission organization and that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce and has one or more organized electricity markets (administered either by it or by another entity) must file with the Commission, no later than January 29, 2007, one of the following:

(i) Tariff sheets and rate schedules that make available long-term firm transmission rights that satisfy each of the guidelines set forth in paragraph (d) of this section; or

(ii) An explanation of how its current tariff and rate schedules already provide for long-term firm transmission rights that satisfy each of the guidelines set forth in paragraph (d) of this section.

(2) Any transmission organization approved by the Commission for operation after January 29, 2007 that has one or more organized electricity markets (administered either by it or by another entity) will be required to satisfy this general rule.

(3) Filings made in compliance with this paragraph (c) must explain how the transmission organization's transmission planning and expansion procedures will accommodate long-term firm transmission rights, including but not limited to how the transmission organization will ensure that allocated long-term firm transmission rights remain feasible over their entire term.

(4) Each transmission organization subject to this general rule must also make its transmission planning and expansion procedures and plans publicly available, including (but not limited to) both the actual plans and any underlying information used to develop the plans.

18 C.F.R. § 42.1(d) provides as follows:

(d) Guidelines for Design and Administration of Long-term Firm Transmission Rights. Transmission organizations subject to paragraph (c) of this section must make available long-term firm transmission rights that satisfy the following guidelines:

(1) The long-term firm transmission right should specify a source (injection node or nodes) and sink (withdrawal node or nodes), and a quantity (MW).

(2) The long-term firm transmission right must provide a hedge against day-ahead locational marginal pricing congestion charges or other direct assignment of congestion costs for the period covered and quantity specified. Once allocated, the financial coverage provided by a financial long-term right should not be modified during its term (the "full funding" requirement) except in the case of extraordinary circumstances or through voluntary agreement of both the holder of the right and the transmission organization.

(3) Long-term firm transmission rights made feasible by transmission upgrades or expansions must be available upon request to any party that pays for such upgrades or expansions in accordance with the transmission organization's prevailing cost allocation methods for upgrades or expansions.

(4) Long-term firm transmission rights must be made available with term lengths (and/or rights to renewal) that are sufficient to meet the needs of load serving entities to hedge long-term power supply arrangements made or planned to satisfy a service obligation. The length of term of renewals may be different from the original term. Transmission organizations may propose rules specifying the length of terms and use of renewal rights to provide long-term coverage, but must be able to offer firm coverage for at least a 10 year period.

(5) Load serving entities must have priority over non-load serving entities in the allocation of long-term firm transmission rights that are supported by existing capacity. The transmission organization may propose reasonable limits on the amount of existing capacity used to support long-term firm transmission rights.

(6) A long-term transmission right held by a load serving entity to support a service obligation should be re-assignable to another entity that acquires that service obligation.

(7) The initial allocation of the long-term firm transmission rights shall not require recipients to participate in an auction.

Sacramento Municipal Utility District, et al. **Docket No. ER06-615, *et al.***
D.C. Cir. Nos. 07-1208, *et al.*

CERTIFICATE OF SERVICE

In accordance with Fed. R. App. P. 25(d), and the Court's Administrative Order Regarding Electronic Case Filing, I hereby certify that I have, this 7th day of December 2009, served the foregoing upon the counsel listed in the Service Preference Report via email through the Court's CM/ECF system or via U.S. Mail, as indicated below:

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