DESIGNING DURABLE NON-RTO ORGANIZED MARKETS

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Synopsis: Utilities face mounting pressures to reduce costs, integrate an increasing amount of new generation onto the grid, and—in many states—achieve decarbonization targets. These pressures have led both utilities and their state regulators to explore forming multilateral electricity markets, even in regions of the country that have historically declined to create Regional Transmission Organizations (RTO). This article provides a history of organized market development and evaluates the structure of five non-RTO[1] organized market frameworks that the Federal Energy Regulatory Commission (FERC or Commission) has approved over the past decade. This article also identifies similarities and differences among the markets regarding (i) market structure, (ii) participation requirements, (iii) governance frameworks, (iv) pricing, and (v) transmission service. Lastly, this article highlights guidelines that designers of imbalance markets, enhanced bilateral markets, and extended day-ahead markets may follow to demonstrate how their market proposals would comply with FERC Order Nos. 888 and 2000.

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1. Reference to "non-RTO markets" in this article refers to market structures that do not require full participation in an RTO or Independent System Operator (ISO), even though several of these markets are organized or administered by a traditional RTO/ISO. This article sometimes uses "RTOs" to include both RTOs and ISOs.

I. INTRODUCTION

New pressures to address mounting grid reliability challenges, reduce energy production costs, and meet decarbonization goals are encouraging states that previously rebuffed organized electricity markets to reconsider forming regional alliances. For example, Colorado's legislature passed a law in 2021 that requires the state's transmission-owning utilities to join an RTO or Independent System Operator (ISO) by 2030.[2] The Colorado bill text states that a qualifying wholesale market will be one that improves service reliability, achieves emissions reductions,

2. Emma Penrod, *Colo. legislators direct all transmission utilities to join an organized wholesale market by 2030*, UTIL. DIVE (June 8, 2021), https://www.utilitydive.com/news/colorado-legislators-direct-all-transmission-utilities-to-join-an-organized/601423/.

and delivers savings to customers, among other features.[3] And Colorado is not alone; several states—including Nevada, New Mexico, and Washington—have set 100% carbon-free electricity goals.[4] According to Berkshire Hathaway Energy's Jonathan Weisgall, "every state west of the Rockies except Wyoming now has a 100% renewables or zero emissions mandate or a utility with an agreement moving it in that direction."[5] Other stakeholders across the West have also called for a western RTO to provide reliability and guide long-term transmission planning, especially to "handle 'surprise events' such as heat waves and wildfires."[6] Drawing on a diverse portfolio of generation resources across a larger footprint may serve all these goals.

Despite the benefits that regional markets may offer to electricity customers, regulators in certain regions of the country have preferred to maintain a system of state-regulated, vertically integrated utilities, which grants states more direct control over the portfolio of generation resources and transmission assets developed within their states. These included the Southeast, Southwest, and Rocky Mountain regions. For more than twenty years, utilities in these regions retained this system for overseeing the development of new power plants and the delivery of electricity to customers. The vertically integrated model has enabled certain utilities to offer their customers comparatively lower electricity rates.[7] Perhaps as a result, state regulators list several reasons for their reticence to join multi-state RTOs, including giving up "a certain amount of control," as Kent Chandler, then Chairman of the Kentucky Public Service Commission, remarked.[8] Regulators in these states also cite greater utility accountability as a benefit of state regulation.[9] As a result,

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3. *Public Utilities Commission Modernize Electric Transmission Infrastructure*, S.B. NO. 21-072 (Colo. 2021) (codified as amended in scattered sections of Colorado Revised Statutes), https://leg.colorado.gov/sites/default/files/2021a_072_signed.pdf.

4. Warren Leon & Anna Ziai, *Table of 100% Clean Energy States*, CLEAN ENERGY STATES ALL., https://www.cesa.org/projects/100-clean-energy-collaborative/guide/table-of-100-clean-energy-states/ (last visited May 28, 2024).

5. Herman Trabish, *The 3 key challenges to expanding the West's real-time energy market to day-ahead trading*, UTIL. DIVE (June 3, 2020), https://www.utilitydive.com/news/the-3-key-challenges-to-expanding-the-wests-real-time-energy-market-to-day/578390/#:~:text=The%20voluntary%20Energy%20Imbalance%20Market,time%20dispatch%2C%20according%20to%20CAISO.

6. Garrett Hering, *Western U.S. Regional grid, reliability efforts reach crossroads in 2023*, S&P GLOB. (Jan. 11, 2023), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/western-us-regional-grid-reliability-efforts-reach-crossroads-in-2023-73650835; *see also* Martha Castañeda, *Powering the West Through a Reliable Energy Grid*, CSG WEST (Dec. 7, 2023), https://csgwest.org/2023/12/07/powering-the-west-through-a-reliable-energy-grid/.

7. *See, e.g.*, *Snohomish, WA Electricity Statistics*, ELEC. LOCAL, https://www.electricitylocal.com/states/washington/snohomish/ (last visited Jan. 14, 2024). Largely due to Washington's abundance of hydropower resources, the average residential electricity rate for customers of Snohomish Public Utility District is 8.44 ¢/kWh, compared to an average of 12.9 ¢/kWh in Philadelphia and 11.5 ¢/kWh in Minneapolis, to give two examples of cities that sit squarely within their RTO's footprint.

8. Robert Zullo, *In the Southeast, Where Big Utilities Rule, Calls for a Real Power Market Persist*, GA. RECORDER (May 7, 2023), https://georgiarecorder.com/2023/05/07/in-the-southeast-where-big-utilities-rule-calls-for-a-real-power-market-persist/.

9. *See, e.g.*, Tim Echols, *PSC Member: Georgia regulators working to fix 'tears' in power grid to prevent Texas-like failure*, SAVANNAH NOW, https://www.savannahnow.com/story/opinion/2021/02/24/georgia-psc-

efforts to form regional electricity markets have not proceeded uniformly across the country, although each of these three regions now hosts an active non-RTO market, as discussed later in this article.

Prior to the 1990s, electric utility companies across the United States were regulated almost exclusively by state public utility commissions. These utilities largely controlled vertically integrated portfolios of generation, transmission, and distribution infrastructure. The costs of building, operating, and maintaining this infrastructure were passed down to the utilities' customers through retail rates, which the state commissions also regulated.[10] Because the generation and distribution of electricity is capital-intensive and benefits from economies of scale, state regulators initially determined that granting local monopolies to individual companies and then closely regulating those monopolies could achieve the state's goal of making reliable electric service available to customers at affordable rates.[11]

As the energy generation mix began to change, however—including due to environmental regulations affecting coal-fired power plants, the U.S. fracking boom, and the development of more efficient renewable generation technologies—federal and some state regulators began to support the development of competitive, wholesale energy markets.[12] These markets were designed to allow merchant-owned electric generating facilities to compete with the utility-owned generators.

Furthermore, several regions of the country—including the Northeast, Mid-Atlantic, Midwest and Northwest—already operated "power pools" that allowed utilities to capture the expanded reliability benefits and cost savings of sharing generating facilities among utilities.[13] New legislation from Congress and regulations issued by FERC, as discussed in the following section, encouraged the transition in these regions from limited power pools to integrated wholesale energy markets.

Over the past decade, both the mounting costs of building and maintaining an increasingly flexible grid and the substantial potential savings from generating energy from near-zero marginal cost resources like wind and solar have encouraged even states that traditionally supported vertically integrated utilities to look for ways to dispatch resources across their region more efficiently. One potential solution is to develop a power pool, in which utilities remain vertically integrated

power-grid-ensure-ready-severe-weather-texas-failure/4539437001/ (updated Feb. 24, 2021) ("Another stitch we have made is resisting the temptation to deregulate the power system in Georgia. We are still a 'regulated' state meaning that from the power plant to the meter behind your house, the power company, with PSC oversight, is responsible and has complete control of ensuring reliability.").

10. *See* FERC v. Elec. Power Supply Ass'n, 136 S. Ct. 760, 767 (2016) (noting that "in the early 20th century, state and local agencies oversaw nearly all generation, transmission, and distribution of electricity").

11. For a brief history of the roots of this regulatory compact in English common law, *see* Heather Payne, *Private (Utility) Regulators*, 50 ENV'T L. 999, 1009 (2020).

12. *See* ENERGY INFO. ADMIN., *The Changing Structure of the Electric Power Industry 2000: An Update* 61 (Oct. 2000), https://grist.org/wp-content/uploads/2010/02/update2000.pdf.

13. *See* Hagler Bailly, *Report on Power Pool Options*, U.S. AGENCY FOR INT'L DEV., BUREAU FOR EUR. & NIS OFFICE OF ENV'T: ENERGY AND URB. DEV. ENERGY AND INFRASTRUCTURE DIV. (Sept. 1997), https://pdf.usaid.gov/pdf_docs/PNACE418.pdf.

but schedule and dispatch their shared power plants to serve the entire system. Another solution is to establish an "energy imbalance market," in which third-party generators are invited to sell energy in real time alongside the energy produced by utility generators. Either of these options stops short of a fully competitive, deregulated wholesale electricity market, and thus potentially allows state regulators[14] to maintain tighter control over the system. But closely held agreements also require greater legal scrutiny; exclusionary participation requirements and restrictive governance provisions in non-RTO organized markets may raise antitrust and market manipulation concerns.

Legal scholars have written extensively about the formation, development, and operation of these wholesale electricity markets.[15] Several have outlined the roles of FERC and the state public utility commissions in regulating the participation of generation and load in these markets, despite disagreeing about the relative effectiveness of the Federal Power Act in guiding such regulation.[16] Others have focused on evaluating the effectiveness of the requirements of FERC Order No. 888 and the market and governance structures of existing RTOs.[17] Some even have proposed alternative market designs that seek to retain consumer and economic benefits while de-emphasizing centralized energy markets.[18] Lastly, both legal and non-legal scholars have studied the monetary benefits of regionalization, concluding that huge amounts of consumer savings may be left on the table in states that do not capture the benefits of competitive markets.[19]

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14. Most utilities that join these markets are subject to general oversight by state commissions, but several are not, such as certain municipal electric utilities and electric cooperatives, which are formally self-regulated but may have their tariffs reviewed by state regulators. *See e.g.*, NRECA INT'L LTD., *Guides for Electric Cooperative Development and Rural Electrification* 8 (Nov. 2016), https://www.nrecainternational.coop/wp-content/uploads/2016/11/GuidesforDevelopment.pdf.

15. *See, e.g.,* Joshua C. Macey & Robert Ward, *MOPR Madness*, 42 ENERGY L.J. 67, 74 (2021); Joshua C. Macey et. al., *Grid Reliability in the Electric Era*, 41 YALE J. ON REG. 164 (2024); Avi Zevin, *Regulating the Energy Transition: FERC & Cost-Benefit Analysis*, 45 COLUM. J. ENV'T L. 419, 455 (2020).

16. *See, e.g.*, Matthew R. Christiansen & Joshua C. Macey, *Long Live the Federal Power Act's Bright Line*, 134 HARV. L. REV. 1360, 1361 (2021); Robert R. Nordhaus, *The Hazy "Bright Line": Defining Federal & State Regulation of Today's Electricity. Grid*, 41 ENERGY L.J. 323 (2020); Joel B. Eisen, *FERC's Expansive Authority to Transform the Electricity Grid*, 49 U.C. DAVIS L. REV. 1783 (2016). *See also* Jody Freeman & David B. Spence, *Old Statutes, New Problems*, 163 U. PA. L. REV. 1, 43 (2014); David B. Spence, *Can Law Manage Competitive Energy Markets?*, 93 CORNELL L. REV. 765, 766 (2008).

17. *See* Shelley Welton, *Rethinking Grid Governance for the Climate Change Era*, 109 CALIF. L. REV. 209 (2021); Michael H. Dworkin & Rachel Aslin Goldwasser, *Ensuring Consideration of the Public Interest in the Governance & Accountability of Regional Transmission Organizations*, 28 ENERGY L.J. 543, 551-52 (2007); Richard A. Drom, *New Metrics for Measuring the Success of A Non-Profit RTO*, 28 ENERGY L.J. 603 (2007).

18. *See* Susan Kelly & Elise Caplan, *Time for A Day 1.5 Market: A Proposal to Reform RTO-Run Centralized Wholesale Eletricity Markets,* 29 ENERGY L.J. 491 (2008).

19. *See, e.g.*, M. Milligan et al., *Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection*, NAT'L RENEWABLE ENERGY LAB. (Mar. 2023), https://www.nrel.gov/docs/fy13osti/57115.pdf; John Tsoukalis et al., *Western Energy Imbalance Service and SPP Western RTO Participation Benefits*, BRATTLE (Dec. 2, 2020), https://spp.org/documents/63517/weis%20and%20spp%20west%20rto%20benefits%20study.pdf; Joshua C. Macey, *Zombie Energy Laws*, 73 VAND. L. REV. 1077 (2020).

No one to date, however, has reviewed how FERC has evaluated non-RTO market proposals or outlined the legal landscape against which FERC and the courts may judge new non-RTO market designs, beyond the standards that Order No. 888 applies to all public utility transmission providers.

Limited action in the appellate courts may partially explain the lack of scholarship. Although FERC has approved several non-RTO market structures during the last decade, the three earliest proposals—two energy imbalance markets and a multi-utility trading arrangement in Colorado—received relatively little pushback from stakeholders. FERC's 2021 approval of the Southeast Energy Exchange Market (SEEM), however, prompted an appeal of the Commission's decision to the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit). Petitioners raised several concerns about SEEM's proposed design, including arguing that the framework did not comply with Order No. 888.[20] The D.C. Circuit noted these concerns in an order that remanded FERC's suite of SEEM orders to the Commission for further consideration.[21]

Since 2021, protestors have alleged that components of two further proposals—the California Independent System Operator's (CAISO) Extended Day Ahead Market (EDAM) and the Southwest Power Pool's (SPP) Markets+ proposal[22]—do not comply with FERC precedent.[23] Taken together, these three market footprints blanket portions of nearly 30 states. Future determinations by FERC and reviewing courts about the compliance of non-RTO markets with the Commission's requirements of open access and non-discriminatory service will impact state regulators, policymakers, and market participants across the country.

This article builds on the existing literature by providing a history of organized market development in the U.S. and evaluating five non-RTO market structures to distill the standards that these markets must meet to receive FERC approval and be upheld by reviewing courts. First, section II reviews how wholesale electricity markets emerged and evolved over the 20th century. Next, section III summarizes key components of five non-RTO market structures that FERC approved between 2015 and 2023. The article evaluates the five markets—plus one market proposal—in pairs: first, two energy imbalance markets: the Western Energy Imbalance Market (EIM) and SPP's Western Energy Imbalance Service Market (WEIS Market); second, two enhanced bilateral markets: the Public Service Company of Colorado (PSCo) Joint Dispatch Agreement (PSCo JDA) and SEEM;

20. Advanced Energy Econ. v. FERC, No. 22-1018, 2022 WL 4593131, at *48 (D.C. Cir. 2022).

21. Advanced Energy United, Inc. v. FERC, 82 F.4th 1095, 1111–12 (D.C. Cir. 2023).

22. At the time of publication, FERC has not yet issued a final order on SPP's Markets+ proposal. On July 31, 2024, FERC staff issued a deficiency letter seeking additional information about SPP's Markets+ proposal before it issues an order approving or rejecting SPP's proposed market design. Accordingly, this paper includes a short overview of what SPP has proposed for Markets+, but does not include Markets+ in the summary tables or conclusion because it has not been approved by FERC and, therefore, does not yet form part of the legal landscape for non-RTO organized markets. *See* Letter informing Southwest Power Pool, Inc. that the 03/29/2024, as amended 04/05/2024, filing is deficient and requesting additional information to be filed within 60 days, Docket No. ER24-1658-000 (July 31, 2024) [hereinafter Markets+ Deficiency Letter].

23. *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, Motion to Intervene and Limited Protest of Western Power Trading Forum, FERC Docket No. ER23-2686-000 at 6-7 (Sept. 21, 2023); *Southwest Power Pool,* Protest of Public Interest Organizations, FERC Docket No. ER24-1658-000 at 16 (Apr. 29. 2024).

and third, two extended day-ahead markets: CAISO's EDAM and SPP's Markets+ proposal.

Following that summary, section IV defines the legal landscape for non-RTO markets broadly. Section V reviews what the Commission has indicated passes legal muster under the Federal Power Act when evaluating different non-RTO market designs. Section V also includes an expanded comparison table, but a condensed version is included here:

Market	Structure & Operational Control	Participation	Governance	Pricing	Transmission (TX) Use
EIM	• 5-minute energy transfers, financial settlement only	•Voluntary; BAA by BAA	• Three- part governance structure: (1) EIM Governing Body, (2) Body of State Regulators, (3) public Regional Issues Forum; CAISO monitors market	• LMP unless mitigated	• As-available TX, lowest priority; standard TX charges
PSCo JDA	• Real-time joint dispatch using SCED, but utilities maintain resource planning & commitment role	• Only LSEs within the PSCo BAA; participants must secure reciprocal TX service	• No formal governance structure	• Service-dependent, ranging from LMP plus $0.50/MWh for Joint Dispatch Energy to LMP plus $10/MWh for Deficit Energy	• As-available TX, lowest priority; $0/MWh
WEIS	• Real-time dispatch using SCED; participants retain operational control	• Participation open to BAAs in the Western Interconnect; all BAAs must secure reciprocal TX; all resources in a participating BAA must register or opt out	• Western Market Executive Committee (WMEC) includes participants; all market rule proposals must be approved by both load-weighted & popular supermajority votes	• LMP, adjusted for marginal losses	• As-available TX, lowest priority; $0/MWh
SEEM	• SEEM matched bilateral energy exchanges in 15-minute increments; participants retain operational control; parties settle transactions bilaterally	• Participants must own or control a source or sink in the SEEM footprint, secure TX service, enter into enabling agreements with 3+ potential counterparties	• Membership Board composes of member representatives; Operating committee oversees market; third party auditor reviews market integrity	• "Split-the-savings" (i.e. midpoint) pricing includes shared financial losses, may be mitigated to MBR price cap	• As-available TX, lowest priority; $0/MWh
EDAM	• Centralized, day-ahead energy auction with must-offer requirement clears bids to produce day-ahead schedules; CAISO settles the market & bill participants	• Voluntary; BAA by BAA, so every resource in a participating BAA must submit bids or self-schedule	• Three- part governance structure: (1) EIM Governing Body, (2) Body of State Regulators, (3) public Regional Issues Forum; CAISO monitors market	• BAA-specific day-ahead LMP; prices mitigated by CAISO DMM as needed	• Participants must either reserve unused TX to receive $0/MWh service or pay a standard TX charge for the use of unreserved TX

Section VI provides a brief update on both past and planned non-RTO market consolidation. Lastly, section VII explains what developers of future markets may wish to consider when designing a new market structure that can attract states seeking to achieve their reliability, cost, and decarbonization goals.

Reviewing new non-RTO market proposals presents FERC with a balancing act: the agency must respect the jurisdictional authority of state regulators to guide energy generation and retail rate-setting decisions within their states' boundaries while at the same time fulfilling its own statutory obligations to ensure just and reasonable wholesale rates, prevent undue discrimination in energy markets, and police anti-competitive behavior.

Getting these balances right is critical to designing—and operating—wholesale markets that deliver the reliability, economic, and environmental benefits demanded by states and their consumers. Effective markets should encourage broad participation, prevent market manipulation, and integrate new resources to secure benefits for consumers. Determining which market structures, governance frameworks, participation models, and even transmission arrangements can produce just and reasonable rates, therefore, is a crucial task for FERC. As much of the country learned from Enron's manipulation of the California energy markets in the early 2000s, market manipulation can greatly reduce the economic savings passed through to consumers.[24] Furthermore, overly restrictive participation requirements or discriminatory governance structures can support exclusive dealing arrangements and other forms of manipulation. Market designs, as a result, must strike a balance between respecting the voluntary and flexible nature of non-RTO markets, which may appeal to some state regulators, and ensuring that any market design can ultimately pass legal muster at FERC and in the courts.

II. How Wholesale Electricity Markets Emerged and Evolved

Electric utilities began to experiment nearly a century ago with ways to pool their assets to reduce the average production cost of electricity and to support regional electric system reliability.[25] In 1927, for example, three utilities that served customers in Pennsylvania and New Jersey formed the country's first continuing power pool.[26] The arrangement allowed the utilities to share generating resources. With the addition of two Maryland utilities in 1956, the power pool rebranded as the Pennsylvania–New Jersey–Maryland Interconnection, or PJM.[27] In the Southwest, World War II catalyzed demand for aluminum and other defense production. To meet the demand for power these industries required, eleven regional utilities formed the Southwest Power Pool in December 1941, just eight days after Congress declared war on Japan.[28]

Utilities in the Northeast took similar steps, albeit for different reasons. The great Northeast blackout of 1965 resulted in cascading power outages that affected a territory from Ontario to Massachusetts and prompted serious conversations about improving regional reliability.[29] New York utility companies in 1966 established the New York Power Pool (NYPP),[30] which in 1977 agreed to interconnect its electric system with that of Ontario Hydro.[31] The stated goal of the Ontario–

24. *Staff Report: Price Manipulation in Western Markets*, FERC Docket No. PA02-2-000 (Mar. 26, 2003).

25. *About NEPOOL*, New Eng. Power Pool, https://nepool.com/about-nepool (last visited Jan. 14, 2024) [hereinafter NEPOOL].

26. *PJM History,* PJM Interconnection, L.L.C., https://www.pjm.com/about-pjm (last visited Jan. 14, 2024).

27. *Electric Power Markets*, FERC, https://www.ferc.gov/industries-data/electric/electric-power-markets/pjm#:~:text=PJM%20was%20founded%20in%201927,%2DMaryland%20Interconnection%2C%20or%20PJM (last visited Jan. 14, 2024).

28. Nathania Sawyer & Les Dillahunty, *The Power of Relationships: 75 Years of Southwest Power Pool*, Sw. Power Pool 20 (May 2016), https://www.spp.org/documents/46282/spp-75th-anniversary-online.pdf.

29. U.S. Can. Power Sys. Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* 104 (Apr. 2004), https://www3.epa.gov/region1/npdes/merrimackstation/pdfs/ar/AR-1165.pdf.

30. Gina Elizabeth Craan, *Introduction to NYISO: New York Market Orientation Course Webinar*, NYSIO 3 (Sept. 17-19, 2024), https://www.nyiso.com/documents/20142/3037451/Introduction-to-NYISO.pdf/f7ad7e5c-65e9-635a-0aee-62709c33c412.

31. NYISO, Interconnection Agreement Between Independent Electricity Market Operator and The New York Independent System Operator, Inc. 2 (May 1, 2022), https://www.nyiso.com/documents/20142/1397306/imonyiso.pdf/73afa0b0-3f20-15e2-1e61-33abf1c919d5.

NYPP expansion was "to achieve, as a result of coordinated interconnection operation, benefits to their respective power systems and thereby to the public."[32] Similarly, in 1971, electric utilities in New England formed the New England Power Pool "to coordinate transmission planning and to achieve economic and reliability benefits through coordinated regional dispatch of power."[33]

Antitrust concerns also boiled up during the late 1960s and early 1970s, prompting both energy regulators and the federal courts to address the potential for electric utilities to behave anticompetitively in these developing markets.[34] In *Otter Tail Power Co. v. U.S.*, for example, the Justice Department brought suit against a transmission-owning utility for refusing either to sell energy at wholesale to municipal customers or to wheel power to the municipalities from third-party suppliers of wholesale energy.[35] The Supreme Court in *Otter Tail* rejected the utility's claims that it should be immune from antitrust regulation for these "refusals to deal" because section 202(b) of the Federal Power Act enabled the Federal Power Commission to remedy anticompetitive behavior by ordering an uncooperative utility to interconnect its system with that of any requesting customer.[36] The Court answered instead that "activities which come under the jurisdiction of a regulatory agency nevertheless may be subject to scrutiny under the antitrust laws," affirming that the Federal Power Commission (now FERC) retained authority to direct Otter Tail to interconnect with its competitors and transmit power to them.[37] The Court clarified that the Federal Power Act should be interpreted as setting out "an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest."[38]

In this and other landmark decisions, the Court affirmed that FERC's approval of utility proposals pursuant to the Federal Power Act must consider those proposals' effects on competition. In *Gulf States Utilities Co. v. Federal Power Commission*, for example, the Court clarified that when a public utility applies pursuant to Federal Power Act section 204 for authority to issue a security, the

32. *Id.*

33. *See* NEPOOL, *supra* note 25, at 1.

34. For example, Congress in 1970 amended the Atomic Energy Act of 1954 to require the Nuclear Regulatory Commission to conduct antitrust reviews of nuclear license applications and, where necessary, to include limited wheeling conditions and other obligations in nuclear licenses to address antitrust concerns. *See* S. Hom & C. Pittiglio, *Standard Review Plan on Transfer and Amendment of Antitrust License Conditions and Antitrust Enforcement*, U.S. NUCLEAR REGUL. COMM'N: OFF. OF NUCLEAR REACTOR REGUL., NUREG-1574, Rev. 2, at iii (Dec. 2007), https://www.nrc.gov/docs/ML0722/ML072260035.pdf. The report notes, however, that Congress in 2005 passed the Energy Policy Act of 2005, which removed the Nuclear Regulatory Commission's antitrust review authority regarding license applications, such that the agency no longer conducts antitrust reviews or imposes new antitrust license conditions.

35. Otter Tail Power Co. v. U. S., 410 U.S. 366, 371 (1973).

36. *Id.* at 373.

37. *Id.* at 372–74.

38. Harvey L. Reiter, *Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation under the Federal Power and Natural Gas Acts*, 18 LAND & WATER L. REV. 1 (1983), *citing Otter Tail Power Co.*, 410 U.S. 366, 374 [hereinafter Competition and Access to the Bottleneck].

Commission must consider any anticompetitive effects of the issuance in determining whether it is "compatible with the public interest."[39] And in *Federal Power Commission v. Conway Corp.*, the Court determined that the Commission must consider allegations that a proposed rate is discriminatory and anticompetitive in effect when evaluating whether that rate is "just and reasonable" under Federal Power Act section 205."[40] The Commission, in 1978, applied these standards in striking down a proposed settlement term that would restrict the ability of wholesale customers of Gulf States Utility Company to resell power delivered by Gulf States. Finding that the Federal Power Act does not allow public utilities to use tariff provisions to foreclose wholesale competition, FERC established what is sometimes called the "least anti-competitive alternatives" test in its conditional approval of the Gulf States settlement.[41] Under the test, the Commission would consider whether resale prohibitions or other measures that curtail competition "serve some significant regulatory purpose which cannot be achieved by a less anticompetitive method."[42] FERC applied a similar theory in conditioning its approvals of several mergers and market-based rate applications on the establishment of open access tariffs or wheeling conditions.[43]

National legislation during the same period expanded competition in both the generation and transmission industries. In 1978, the Public Utilities Regulatory Policies Act initiated deregulation of energy production by providing a pathway for certain qualifying facilities—mostly renewable generators—to sell their energy to utilities for resale to end-use customers.[44]

Other policy changes, including the passage of the National Energy Policy Act in 1992, expanded competition among incumbent utilities.[45] By the mid-1990s, several regions of the United States began to explore how competition among wholesale generators could both support a non-discriminatory transmission system and provide consumers with a choice of energy suppliers. PJM, for example, began its transition to becoming a fully independent system operator in 1993, more than thirty years after it started scheduling and dispatching a combined system.[46] In 1997, after receiving approval from FERC, PJM opened its first bid-based energy market.[47]

39. Gulf States Utils. Co. v. FPC, 411 U.S. 747, 749 (1973).

40. FPC v. Conway Corp., 426 U.S. 271, 279 (1976).

41. Competition and Access to the Bottleneck, *supra* note 38, at n.12.

42. *Gulf States Utils. Co*., 5 FERC ¶ 61,066 at *3 (1978).

43. *See, e.g.*, Ne. Utilities Serv. Co. v. FERC, 993 F.2d 937, 954 (1st Cir. 1993) (upholding FERC's decision to condition its approval of the merger of Northeast Utilities and the Public Service Company of New Hampshire on Northeast Utilities' offering any spare transmission capacity for wheeling use); *Pub. Serv. Co. of Indiana, Inc.*, 51 F.E.R.C. ¶ 61,367, 62,189–90 (1990) (accepting Public Service Company of Indiana's application to sell power at market based rates on the condition that the utility file an open access transmission tariff).

44. *IRC History*, ISO/RTO COUNCIL, https://isorto.org/ (last visited Jan. 14, 2024).

45. *Id*.

46. PJM INTERCONNECTION, L.L.C., *supra* note 26, at 1.

47. *Id.*

III. FOUNDATIONAL FERC ORDERS

The Commission's issuance of several landmark orders laid the foundation for the legal and regulatory regime that transmission owners in both RTO and non-RTO regions still face today. Concurrently with the development of centralized energy markets in the 1990s, FERC began to support the development of regional transmission systems both by issuing policy guidance and through formal rule-making proceedings. FERC issued a policy statement in 1993 that both encouraged the development of "regional transmission groups" (RTG)[48] and provided guidance regarding the composition of regional transmission group agreements (RTG Policy Statement).[49] The RTG Policy Statement noted that several transmission groups were developing in parallel across the country and that "there is a need for flexibility in forming these voluntary associations and the agreements that govern them, in order to reflect specific geographic, operational, historical, or other circumstances of the parties."[50] The RTG Policy Statement, therefore, allowed parties to propose "any RTG agreement that they believe satisfies their contractual needs and complies with the substantive standards of the FPA," but established a policy that RTG agreements should, at a minimum, reflect certain foundational characteristics.[51] FERC approved the Western Regional Transmission Association in 1995 as the first regional transmission group to comply with the RTG Policy Statement.[52]

In 1996, FERC issued Order No. 888, which required all public utilities to provide "open access" to their transmission systems—that is, to provide transmission service to third parties on substantially the same terms as the utility would provide transmission to itself.[53] Complying with Order No. 888 required utilities to file Open Access Transmission Tariffs (OATT), which set out standard and non-discriminatory terms for taking transmission service.[54] For many utilities, this requirement necessitated the development of a new, standardized menu of transmission services. For others, including many utilities that had filed OATTs to satisfy FERC's earlier, conditional approvals of their mergers, Order No. 888 required more moderate revisions to tariffs that were already on file with the Commission.

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48. The Commission defines an RTG as a voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning (and expansion), operation and use on a regional (and interregional) basis. *See Policy Statement Regarding Regional Transmission Groups*, 58 Fed. Reg. 41,626, at 41,626-27 (1993) (to be codified at 18 C.F.R. pt. 2).

49. *Id.* at 41,629.

50. *Id.*

51. *Id.* at 41,629–30. The foundational characteristics included seven basic components: (1) broad membership, (2) coordination with states, (3) an obligation to provide transmission services to members, (4) coordinated transmission planning, (5) non-discriminatory governance procedures, (6) voluntary dispute resolution procedures, and (7) an exit provision for members.

52. Lori A. Burkhart, *WRTA First to Get FERC Final Approval*, PUB. UTIL. FORT. (July 1, 1995), https://www.fortnightly.com/fortnightly/1995/07/wrta-first-get-ferc-final-approval.

53. *History of OATT Reform*, FERC, https://www.ferc.2gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform (last updated Jan. 18, 2023).

54. *Id.*

Nearly ten years after its issuance of Order No. 888, FERC, in 2005, issued a Notice of Inquiry to seek input on whether the Commission's *pro forma* OATT needed further reform, in light of changes to the structure and electric utility industry.[55] Following FERC's issuance of a Notice of Proposed Rulemaking (NOPR) on this question and the collection of comments on both documents, the Commission issued order No. 890, which adopted certain reforms proposed in the NOPR to "strengthen the *pro forma* [OATT]," reduce opportunities for undue discrimination, and increase transparency around transmission system planning processes.[56] Among other reforms, Order No. 890 required transmission providers to include transmission customers in their transmission planning processes and increased the transparency requirements for OATTs so that both customers and FERC's Office of Enforcement could better "detect undue discrimination."[57]

Although Order Nos. 888 and 890 reduced opportunities for transmission owners to discriminate in their provision of transmission service, utilities largely planned and operated their systems independently of each other. FERC identified several "deficiencies" in transmission providers' existing transmission planning and cost allocation procedures, and, in 2011, issued Order No. 1000 to require transmission providers to implement reforms.[58] More specifically, Order No. 1000 required that each public utility transmission provider: (i) participate in a regional transmission planning process that produces a regional transmission plan and has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation, (ii) revise its OATT to include guidelines for selecting competitive transmission projects, (iii) eliminate a federal right of first refusal from its OATT for constructing certain new transmission facilities, and (iv) engage in interregional transmission planning coordination and cost allocation.[59]

In addition to the above-noted reforms to require non-discriminatory access to transmission, FERC "encouraged the voluntary formation of [RTOs] to administer the transmission grid on a regional basis throughout North America."[60] The

55. *Id.*

56. Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service*, FERC STATS. & REGS. ¶ 31,241 (2007), 72 Fed. Reg. 12,266 (Mar. 15, 2007) [hereinafter Order No. 890]; *order on reh'g*, Order No. 890-A, 73 Fed. Reg. 2,984 (Jan. 16, 2008), FERC STATS. & REGS. ¶ 31,261 (2007) [hereinafter Order No. 890-A].

57. Order No. 890, *supra* note 56, at P 6. *But see Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161 at P 66 (2018) (finding "that the Order No. 890 transmission planning reforms were intended to address concerns regarding undue discrimination in grid expansion [and] to the extent that PG&E asset management projects and activities do not expand the grid, they do not fall within the scope of Order No. 890 [reforms]").

58. Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, FERC STATS. & REGS. ¶ 31,323 (2011), 76 Fed. Reg. 49,842, at P 4 (Aug. 11, 2011) (to be codified at C.F.R. pt. 35) [hereinafter Order No. 1000].

59. *Id.* at PP 8, 146, 284, 325.

60. *RTOs and ISOs*, FERC, https://www.ferc.gov/power-sales-and-markets/rtos-and-isos#:~:text=Subsequently%2C%20in%20Order%20No.,North%20America%20(including%20Canada) (last visited Jan. 17, 2024).

Commission envisioned that RTOs would "operate transmission systems and develop innovative procedures equitably."[61] In the rulemaking process for Order No. 2000, the Commission weighed whether to mandate RTO participation or to continue to pursue a voluntary approach.[62] The Commission determined in Order No. 2000 that although "it is clear that RTOs are needed to resolve impediments to fully competitive markets," the agency "should pursue a voluntary approach to participation in RTOs."[63] Thus, Order No. 2000 required transmission-owning public utilities to evaluate potential RTO participation but stopped short of requiring utilities to join RTOs.[64]

To aid in what the Commission still called the "voluntary development of RTOs," Order No. 2000 also established certain minimum characteristics and functions that each market must satisfy before it can be approved by FERC to serve as an RTO.[65] The minimum characteristics of an RTO applied to four categories: (i) independence, (ii) scope and regional configuration, (iii) operational authority, and (iv) short-term reliability.[66] The minimum functional requirements of an RTO were organized into eight categories: (i) tariff administration and design; (ii) congestion management; (iii) parallel path flow; (iv) ancillary services; (v) public posting of open access system information, total transmission capability, and available transmission capability; (vi) market monitoring; (vii) planning and expansion; and (viii) interregional coordination.[67] The Commission described its RTO requirements as creating an "open architecture" policy for RTO development, as opposed to a more top-down, "cookie cutter" organizational format.[68]

Although FERC did not mandate RTO formation, many former power pools in the years leading up to Order No. 2000's issuance had already begun to function more like the Commission's conception of RTOs. These included CAISO, ISO New England, and the New York Independent System Operator.[69] After 2000, PJM Interconnection (PJM), the Midcontinent Independent System Operator (MISO), and SPP formalized as RTOs, which extended the ability to participate in regional markets to more than twenty-five additional states.[70]

Utilities in other regions of the country, however, either declined to join RTOs or proposed regional transmission conglomerates that were rejected by state or federal regulators. One of these failed RTOs, SeTrans, was proposed by nine

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61. *Electric Power Markets*, FERC, https://www.ferc.gov/electric-power-markets (last visited Jan. 14, 2024).

62. Order No. 2000, *Regional Transmission Organizations*, FERC STATS. & REGS. ¶ 31,089 (2000), 65 Fed. Reg. 809 (2000) [hereinafter Order No. 2000].

63. *Id.* at 834.

64. *Id.* at 812.

65. *Id.* at 811-12.

66. Order No. 2000, *supra* note 62, at 811.

67. *Id.*

68. *Id.*

69. Richard Doying, *Order 2000 Revisited: FERC Market Expansion and RTO Policy—Where Are We Now?*, HARV. ELEC. POL'Y GRP. 5 (Apr. 20, 2021), https://hepg.hks.harvard.edu/sites/hwpi.harvard.edu/files/hepg/files/doying-hepg-beyong_rto_1000_for_posting.pdf?m=1626199870.

70. *Id.*

transmission-owning utilities in the Southeast, a region that had repeatedly resisted developing a multi-state wholesale market.[71] FERC issued an order in 2002 finding that the proposed business model and governance structure of SeTrans complied with Order No. 2000.[72] By the following year, however, the utilities that had proposed SeTrans had abandoned the initiative, announcing that it was "highly unlikely" that the group could agree on final market design parameters that would satisfy both Southeast state regulators and FERC.[73]

For more than fifteen years after SeTrans' dissolution, the Southeast retained its existing system of state public utility regulation of mainly vertically integrated utilities. Over the same period, utilities in the West and Rocky Mountain regions of the country maintained a similar regulatory framework. However, increasing pressures to interconnect massive amounts of new generation resources, and—in some states—make progress toward achieving state-level decarbonization goals recently have revived conversations in these three regions about developing regional electricity markets. The following section discusses market development initiatives in each.

IV. THE CREATION OF MODERN NON-RTO MARKETS

Over the last decade, regions across the country have explored how to unlock the economic and reliability benefits of generating and selling energy across a wider market footprint without sacrificing robust state-level oversight. Several of these regions have proposed non-RTO organized markets to facilitate the trading of energy, first in the real-time energy markets and most recently in CAISO's day-ahead energy market. This article evaluates five non-RTO market structures that have been approved by FERC since 2014. Although the five markets vary in their characteristics, this article consider them in categories: first, two energy imbalance markets; second, two enhanced bilateral markets; and lastly, CAISO's extended day-ahead market. The section on enhanced bilateral markets also provides a brief overview of a sixth proposed market, SPP's Markets+ proposal. This organization approximately tracks the development pathway for non-RTO organized markets, which began with CAISO's creation of the EIM, progressed through two versions of bilateral market enhancements, and continues today with the development both of CAISO's EDAM and SPP's proposed day-ahead offering, Markets+.[74]

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71. Mary O'Driscoll, *SeTrans Breakup Adds to Mandatory RTO Debate*, E&E NEWS (Dec. 2003), https://subscriber.politicopro.com/article/eenews/2003/12/05/setrans-breakup-adds-to-mandatory-rto-debate-242110.

72. FERC in its order, however, did not address other details of an RTO for SeTrans. *See Cleco Power LLC,* 101 FERC ¶ 61,008 at PP 18-19 (2002) ("The purpose of SeTrans Sponsors' instant Petition is to seek approval and preliminary guidance only on certain issues related to the proposed formation of the SeTrans RTO. . . . Accordingly, this order makes a finding only on SeTrans Sponsors' proposed business model and ISA selection process, and generally the governance structure, and provides preliminary guidance on certain limited issues that have been raised in SeTrans Sponsors' Petition.").

73. O'Driscoll, *supra* note 71.

74. Although PSCo's Joint Dispatch Agreement predated SPP's launch of its Western Energy Imbalance Service Market, SPP WEIS is evaluated together with CAISO's EIM because both real-time imbalance markets share several common characteristics.

Specifically, this section examines: (1) the overall market structure and allocation of operational control for each paradigm, (2) participation requirements for the market, (3) the system of market governance, (4) how energy transactions are priced, and (5) how transmission service to facilitate transactions is procured and paid for. The following section highlights commonalities and differences among these market designs to define the threshold for what may pass legal muster with FERC—and potentially reviewing courts—when filing parties propose a new market design.

A. Imbalance Markets

The first type of organized market framework to be offered to non-RTO market participants was that of an energy imbalance market. Two such markets are described below.

1. Western Energy Imbalance Market

CAISO in February 2014 filed with FERC its proposal to offer participation in the imbalance portion of its real-time energy market—the EIM—to non-CAISO Balancing Authority Areas (BAA) in the Western states.[75] According to CAISO, the extension of its EIM structure to external BAAs did not represent the creation of a new market,[76] but would provide "other [BAAs] the opportunity to participate in the real-time market for imbalance energy that CAISO operates in its own [BAA]."[77] The proposal was designed to allow the voluntary participation of other balancing authorities without disrupting the existing market structure.[78] By leveraging a "wider and more diverse pool of supply resources" and by using an automated market process, CAISO asserted other Western BAAs could both reduce their energy costs and better facilitate the integration of renewable resources onto their systems.[79]

Certain stakeholders expressed concern over discrete aspects of CAISO's proposal, but many agreed that "expansion of CAISO's energy imbalance market beyond its BAA [would] provide customers with a range of benefits, including reduced costs, more efficient dispatch, improved integration of renewable resources, and enhanced reliability."[80]

In accepting the proposal, FERC found that CAISO's proposal complied with FPA section 205 but noted that the EIM filing differed "from [RTO] or [ISO] filings of a consolidated tariff for an overall footprint."[81]

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75. *California Independent System Operator Corp.*, 147 FERC ¶ 61,231 (June 19, 2014) [hereinafter EIM Order].

76. *Id.* at P 74; *see Cal. Indep. Sys. Operator Corp.*, ISO Tariff Amendments to Implement an Energy Imbalance Market, FERC Docket No. ER14-1386-000 at 2 (Feb. 28, 2014) [hereinafter CAISO EIM Proposal].

77. *Cal. Indep. Sys. Operator Corp.*, Filing of CAISO Rate Schedule, FERC Docket No. ER21-1003-000 at 1 (Jan. 29, 2021).

78. EIM Order, *supra* note 75, at PP 6–7.

79. *Id.* at P 3.

80. *Id.* at P 76 & n.93.

81. *Id.* at P 76.

a. Market Structure & Operational Control

Under CAISO's proposal, participating BAAs would be able to purchase and sell real-time energy in CAISO's existing energy imbalance market on a five-minute basis.[82] CAISO would financially settle the EIM using locational marginal prices (LMP) that reflect "the clearing price of energy, the marginal cost of congestion, and the marginal cost of losses at the delivery location."[83] The EIM would build upon CAISO's 2014 introduction of a 15-minute energy market in response to FERC Order No. 764, which directed ISOs to offer intra-hour transmission scheduling in order to reduce barriers to the participation of variable energy resources in its markets.[84]

Under CAISO's EIM market structure, participating BAAs retain operational control over their transmission systems, but certain provisions would separate EIM transfers from normal energy sales.[85] For example, EIM transfers—transfers of imbalance energy from one EIM Entity BAA to another through the EIM—would not require individual resource e-Tags and would instead be modeled as dynamic schedules between CAISO and each relevant EIM entity.[86] Stakeholders generally approved of the market structure that CAISO proposed for the EIM, although several protested discrete market design choices, such as the application and allocation of uplift, resource sufficiency requirements, transmission charge and use issues, and settlements.[87]

In approving the overall EIM market design, the Commission agreed with CAISO that its proposal did not represent a new market, but instead would extend CAISO's existing real-time market to more participants.[88] The Commission explained, however, that "the proposal encompasses—within one real-time balancing market—entities within an ISO market and entities outside an RTO/ISO market operating BAAs pursuant to OATTs" and noted that this major structural difference requires treatment by FERC that differs from the regulation of a traditional ISO.[89] Overall, the Commission noted the voluntary nature of the EIM and the wide range of benefits that CAISO's proposed market structure might deliver to Western customers.[90]

b. Participation

Participation in the EIM would be voluntary both for BAAs and for individual resource owners within a participating BAA.[91] In order to participate, each

82. EIM Order, *supra* note 75, at P 2.

83. CAISO EIM Proposal, *supra* note 76, at 5.

84. Order No. 764, *Integration of Variable Energy Resources*, 139 FERC ¶ 61,246 (2012) (to be codified at 18 C.F.R. pt. 35).

85. EIM Order, *supra* note 75, at P 10.

86. *Id.* at P 27.

87. *See, e.g., Id.* at PP 132, 142.

88. *Id.* at P 76.

89. EIM Order, *supra* note 75, at P 76.

90. *Id.*

91. *Id.* at P 8.

interested BAA would enter into an implementation agreement with CAISO that sets out certain milestones and fees to accommodate CAISO's evaluation—and, ultimately, facilitation—of that BAA's participation in the EIM.[92] Participation in the EIM would not require any participating BAA to "join" CAISO.[93] CAISO would run its market software to economically dispatch the energy systems of EIM Entities and would financially settle the EIM, but that EIM Entities would be responsible for allocating the costs and revenues for imbalance sales according to their own respective OATTs.[94]

CAISO introduced four new types of participants in its real-time market, including EIM Entities and EIM Participating Resources, the resources within those BAAs that would offer imbalance energy into CAISO's real-time market.[95] Although CAISO proposed that EIM participation rules would be unique to the new market, it pledged that these rules would ensure comparable treatment between EIM participants and other CAISO market participants.[96]

In approving the EIM proposal FERC declined to spill ink specifically on CAISO's participation requirements. FERC determined when addressing seams issues, however, that CAISO had "taken sufficient steps to ensure that EIM transfers between EIM Entity BAAs and CAISO will not adversely impact non-participant systems."[97]

c. Governance

The EIM governance framework includes a Governing Body, participation by the Body of State Regulators (BOSR), and the convening of a Regional Issues Forum.[98]

Established by charter agreement in December of 2015, the five-member EIM Governing Body shares its authority with the CAISO Board of Governors—CAISO's board of directors—over rules specific to participation in the EIM.[99] New appointees to the Governing Body are selected by a nominating committee composed of stakeholder representatives and confirmed by the existing Governing

92. *Id.* at P 10. CAISO also explained that as part of the EIM's voluntary participation framework, a BAA's termination of its participation in the EIM would not be subject to an exit fee because each BAA will have paid its associated startup costs before joining and will remain responsible for any charges incurred during its participation in the EIM. CAISO proposed to retain the authority to suspend the participation of any EIM Entity within the first 60 days of its participation in the EIM if operational issues on its system adversely affect the overall market's operation. *See* EIM Order, *supra* note 75, at PP 13, 16.

93. EIM Order, *supra* note 75, at P 8.

94. *Id.* at P 8-9.

95. *Id.* at P 18.

96. *Id*.

97. EIM Order, *supra* note 75, at P 250.

98. CAL. INDEP. SYS. OPERATOR, CHARTER FOR ENERGY IMBALANCE MARKET GOVERNANCE 2 (Dec. 18, 2015), https://www.caiso.com/documents/decision-policies-implement-eim-governance-attach-b-charter-july-2021.pdf [hereinafter EIM Charter].

99. *Id.*

Body members.[100] Five stakeholder constituencies each contribute one voting representative to the nominating committee: (1) the EIM Entities, (2) participating transmission owners, (3) suppliers and marketers of generation, (4) publicly-owned utilities, and (5) state regulators.[101] Three additional constituencies each contribute one non-voting representative: (1) the current EIM Governing Body, (2) the CAISO Board of Governors, and (3) public interest groups and consumer advocates.[102] In total, the eight-member nominating committee is composed of these five voting and three non-voting representatives.

The BOSR meets periodically and exists primarily to serve as a forum for state regulators to track EIM and other CAISO developments that may impact their jurisdictional responsibilities.[103] The BOSR is independent from the CAISO Board of Governors, and participation on the BOSR does not preclude any state commission or commissioner from taking individual positions before FERC or in other fora. The Regional Issues Forum, convened approximately quarterly, is organized by a group of eleven sector liaisons.[104] Meetings of the Regional Issues Forum are open to the public and are designed to allow stakeholders to discuss issues related to the EIM or other related CAISO initiatives.

CAISO proposed that its Department of Market Monitoring (CAISO DMM) would provide market-monitoring services for the EIM participants in CAISO's real-time market.[105] Furthermore, CAISO would apply real-time local market power mitigation—which mitigates bids that might create non-competitive prices at transmission constraints—to the transfers of EIM market participants, as needed.[106]

Although a handful of commenters expressed support for CAISO's proposed governance and market monitoring regime, several others argued that "extending the authority of an RTO or state entity to a hybrid or multi-state market is unprecedented and does not comport with the Commission's independence criteria."[107] In support of this argument, one protester cited prior Commission orders regarding PJM and MISO to argue that the Commission had previously discouraged one state's ability to impact an RTO's operations disproportionately.[108]

CAISO noted in response that FERC had already found the CAISO DMM to be sufficiently independent of the ISO in compliance with Order No. 719. CAISO also argued that FERC had already accepted its governance structure as compliant

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100. Jennifer Gardner, *Decision on EIM Governing Body Nomination*, W. ENERGY IMBALANCE MKT. (Aug. 28, 2019), https://www.westerneim.com/Documents/DecisiononEIMGoverningBodyNomination-Presentation-Jan2020.pdf.

101. *Id.* at 4.

102. *Id.*

103. *Body of State Regulators*, W. ENERGY IMBALANCE MKT., https://www.westerneim.com/Pages/Governance/EIMBodyofStateRegulators.aspx (last visited Jan. 14, 2024).

104. *Regional Issues Forum*, W. ENERGY IMBALANCE MKT., https://www.westerneim.com/Pages/Governance/RegionalIssuesForum.aspx (last visited Jan. 14, 2024).

105. EIM Order, *supra* note 75, at P 60.

106. *Id.* at PP 15, 61.

107. *Id*. at PP 105-06, n.34.

108. *Id*. at P 106, n.135.

with the independence requirements of Order Nos. 888, 2000, and 719, and that FERC had not established different independence requirements for multi-state ISOs.[109] Furthermore, FERC had not required changes to CAISO's governance structure when a Nevada-based electric utility joined CAISO.[110] Nor did FERC require MISO to revise its governance structure when it began providing reliability coordination service to non-MISO entities.[111]

In approving the EIM proposal, FERC found that the proposed governance and market monitoring structures were just and reasonable. FERC agreed with CAISO that the CAISO Board of Governors satisfies the Commission's independence requirements.[112] FERC also agreed with CAISO that the earlier integration of a Nevada cooperative had not necessitated changes to CAISO's governance. Noting the voluntary nature of the market and the availability of market participants to seek recourse with the Commission, FERC also concluded that the CAISO DMM would provide sufficiently independent and competent monitoring services for the EIM, and that CAISO had proposed a sufficient market oversight framework.[113]

d. Pricing

CAISO proposed to financially settle the EIM using LMPs that reflect the clearing price of energy, "the marginal cost of congestion, and the marginal cost of losses at the delivery location."[114] CAISO would allocate costs for energy transfers to each participating BAA, but that BAAs would settle these costs with market participants within their footprints.[115] Where necessary, CAISO would mitigate the bids or offers of EIM market participants, as required by their market-based rate authorizations.[116]

In approving the EIM proposal FERC declined to comment specifically on CAISO's proposed use of LMPs for EIM transfers. The Commission's top-line determinations in accepting CAISO's proposal, however, noted that the expansion

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109. EIM Order, *supra* note 75, at P 108 (citing *Cal. Indep. Sys. Operator Corp.*, 112 FERC ¶ 61,010 at PP 18-36 (2005); *Cal. Indep. Sys. Operator Corp.*, 133 FERC ¶ 61,067 at PP 46-57 (2010)).

110. *Id.*

111. *Id.*

112. *Id*. at P 109 (citing *Cal. Indep. Sys. Operator Corp.*, 129 FERC ¶ 61,157 (2009), *order on compliance*, 134 FERC ¶ 61,050 (2011) (accepting CAISO's Order No. 719 compliance filing with language regarding independence and oversight of the Department of Market Monitoring); 112 FERC ¶ 61,010, at PP 18-36 (finding that CAISO's proposed Board selection process was "consistent with the principles of independence that the Commission has previously enumerated and acceptable for purposes of the Order Nos. 888 and 2000 independence requirements" and that the current Board was independent pursuant to Order No. 888); *Cal. Indep. Sys. Operator Corp.*, 133 FERC ¶ 61,067 at PP 46-57 (2010) (finding that CAISO's governance structure meets the requirements of Order No. 719: inclusiveness, fairness in balancing diverse interest, representation of minority position, ongoing responsiveness, and public posting of mission statement or organizational charter)).

113. EIM Order, *supra* note 75, at P 109.

114. CAISO EIM Proposal, *supra* note 76, at 5.

115. *Id.* at 3.

116. *Id.* at 40.

of CAISO's energy imbalance market—including, presumably, the pricing of energy imbalance transfers—was just and reasonable.[117]

e. Transmission Service

Transmission access to the EIM would be provided to participating resources under the applicable transmission providers' tariffs.[118] Energy transfers would be scheduled and dispatched between BAAs participating in the EIM only over transmission rights specifically made available for that purpose.[119] CAISO explained that imbalance energy transfers would not compromise the transmission rights of non-participants.[120]

CAISO did not propose to assess an incremental transmission charge for the use of unreserved transmission to support EIM transfers between participating BAAs.[121] Instead, to avoid rate pancaking, EIM transfers would be exempt from wheeling charges that might otherwise be imposed by the exporting BAA. Transfer recipients would only pay their local transmission charge.[122] CAISO argued that because EIM transfers represent a new transmission service under its tariff, its proposed treatment of EIM transfers would not amount to a discounted transmission service.[123] CAISO characterized this approach as consistent with Commission precedent that directs the removal of pancaked transmission rates "within and between ISOs and RTOs."[124]

Several commenters protested CAISO's proposal to exempt EIM transfers from wheeling charges, arguing that exempting EIM transfers from wheeling charges is unduly discriminatory because otherwise-identical transactions would be charged differently for transmission "depending on whether the transaction is EIM or non-EIM, which will give a price advantage to resources participating in the EIM."[125] Some argued that CAISO's proposal set forth an unduly preferential transmission rate for EIM transactions and constitutes preferential treatment for EIM resources.[126] Other utilities supported the proposal, arguing that exempting EIM transfers from transmission charges is critical to the efficient operation of the market.[127] Another argued that, although avoiding rate pancaking is beneficial, CAISO's proposal functionally establishes a "free transmission zone" that applies exclusively to EIM transactions.[128] Commenters cited to Order No. 2000 and several prior Commission orders in arguing that pancaked rates should be removed

117. EIM Order, *supra* note 75, at P 76.
118. *Id.* at P 11.
119. *Id.*
120. *Id.*
121. EIM Order, *supra* note 75, at P 12.
122. *Id.* at P 53.
123. *Id*. at P 127.
124. *Id.* at P 126.
125. EIM Order, *supra* note 75, at P 129.
126. *Id.* at PP 129–30.
127. *Id.* at P 129.
128. *Id.* at P 132.

for all market participants and not a subgroup of market participants.[129] One suggested that implementing a single OATT transmission rate across all market timeframes would be a more appropriate means of eliminating rate pancaking.[130]

CAISO explained in reply that transactions within the CAISO markets are not charged pancaked rates and, thus, that it was reasonable to apply the same policy to EIM transfers.[131] Although the proposed EIM would be the first energy imbalance market to extend beyond an existing RTO footprint, CAISO argued that the removal of pancaked rates for the entire EIM would not be unduly discriminatory because the EIM would provide a distinctly different service than CAISO's then-existing day-ahead and fifteen-minute energy markets.[132]

FERC approved CAISO's proposal to exempt EIM transfers from wheeling access charges, explaining that EIM transfers would not be similarly situated to other CAISO energy exports. FERC concluded instead that "the EIM represents a sufficiently different market structure to justify different rate treatment of EIM transfers and other CAISO exports."[133] Even if an EIM transfer uses the same transmission lines as other energy exports, FERC determined the transmission service used to deliver imbalance energy to be distinct from the service used for scheduled transactions.[134]

Noting that the elimination of the seam between CAISO and the EIM Entity BAAs would promote more efficient and competitive energy markets and would allow customers to draw on a wider pool of generation resources, FERC determined that eliminating pancaked transmission rates within the EIM was just and reasonable.[135] The Commission explained that although it had required the elimination of intra-RTO pancaking and had not previously required the elimination of inter-RTO pancaking,[136] the facts underlying the EIM— "an energy imbalance market utilizing an existing ISO's market software beyond the borders of that ISO"—did not fit cleanly into either category.[137] The Commission reasoned that CAISO's proposal to eliminate rate pancaking within the EIM footprint was designed to address goals similar to those underlying organized markets, such as enhanced efficiency and reliability.

The Commission supported its finding by citing to *Illinois Power Company*, in which FERC had allowed transmission rates to remain pancaked for entities outside of two participating RTOs but had allowed for non-pancaked rates between the RTOs. In *Illinois Power Company*, FERC had reasoned that non-pancaked rates "create a benefit for customers" within the RTO and "may provide to

129. EIM Order, *supra* note 75, at P 134
130. *Id.* at P 132.
131. *Id.* at P 144.
132. *Id.* at P 145.
133. EIM Order, *supra* note 75, at P 153.
134. *Id.* at P 154.
135. *Id.* at P 156.
136. *Id.* at P 155.
137. EIM Order, *supra* note 75, at P 155.

[RTO] customers additional supply alternatives that might otherwise be uneconomic."[138] The Commission analogized this circumstance to the EIM in accepting CAISO's proposed use of available transmission, finding that the proposed non-pancaked rates for the EIM would not only provide a benefit to EIM participants, but also could provide "an incentive for EIM participation that need not be offered to non-EIM entities."[139]

2. SPP WEIS Market

SPP, in October of 2020, filed a proposal to create the WEIS Market and to offer energy imbalance service through the WEIS Market to non-SPP RTO members. SPP's proposal consisted of: (1) tariff revisions to implement the WEIS Market, (2) Western Joint Dispatch Agreements (WJDA) executed by prospective WEIS Market participants, and (3) a charter for the Western Market Executive Committee (WMEC), which SPP proposed would serve as the governing body for the WEIS Market.[140] SPP's revised proposal built on an earlier proposal, which FERC had rejected in July of 2020 with guidance.[141]

SPP's WEIS Market Tariff, as revised, provided for the implementation of a market, to be operated by SPP, for five-minute energy imbalance service.[142] SPP would administer the WEIS Market separately from the existing wholesale energy market that it operates for RTO members.[143] At the time of filing, eight utilities had indicated interest in joining the WEIS Market and had taken steps to become WEIS Market participants.[144]

FERC accepted SPP's WEIS Market proposal, effective February 2021, finding that the WEIS Market was designed to yield economic and reliability benefits to market participants in the West.[145] The Commission explained that the WEIS Market not only would make a broader pool of resources available to provide energy imbalance service than did SPP's existing RTO footprint, but also that it could both improve reliability and facilitate the integration of an increasing number of variable energy resources.[146] The Commission noted that it had previously recognized the benefits that energy imbalance markets could yield and determined that it expected the WEIS Market to deliver similar benefits.[147]

138. *Id.* at P 157 (citing *Ill. Power Co.*, 95 FERC ¶ 61,644, *reh'g denied*, 96 FERC ¶ 61,026 (2001)).
139. *Id.*
140. *Southwest Power Pool, Inc.*, 173 FERC ¶ 61,267 at P 1 (2020) [hereinafter WEIS Market Order].
141. *Id*. at P 4 (citing *Southwest Power Pool, Inc.*, 172 FERC ¶ 61,115 (2020) at PP 18-19).
142. *Id*. at P 5.
143. *Id*.
144. WEIS Market Order, *supra* note 140, at P 6.
145. *Id*. at P 20.
146. *Id*.
147. *Id*. (citing 147 FERC ¶ 61,231, at P 75 (describing benefits of CAISO's energy imbalance market in the Western Interconnection); *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,289 at P 2 (describing benefits of SPP's energy imbalance market that operated in the Eastern Interconnection from 2007-2014)).

a. Market Structure & Operational Control

The WEIS Market was designed to implement security constrained economic dispatch (SCED) to optimize the centralized dispatch of "all available participating resources across the WEIS Market footprint to help balance load and generation."[148] SPP would settle all imbalance energy within participating BAAs in the WEIS Market and thus would require all resources—load and generation—located within the WEIS Market footprint to register with the market.[149] If entities within a participating BAA opted not to execute the WJDA, SPP would settle any imbalance energy associated with their resources with their host BAA on their behalf.[150]

The WEIS Market structure would not require participants to transfer functional control of their generation or transmission assets to SPP.[151] Furthermore, the market would not determine unit commitments or clear any non-energy products, such as operating reserves. SPP would neither consolidate nor administer market participants' OATTs but would serve only as the market operator.[152]

FERC approved SPP's overall market design, which was not protested, explaining that SPP had addressed the Commission's concerns with its previous filing and had demonstrated that its revised filing "presents a just and reasonable regional solution."[153]

b. Participation

Prospective WEIS Market participants would be required to execute a Western Joint Dispatch Agreement (WJDA), which establishes a contractual relationship between SPP and a prospective market participant and allocates to the participant its share of total administrative costs.[154] At SPP's time of filing, all eight utilities seeking to participate in the WEIS Market at its inception had executed WJDAs.[155] FERC accepted SPP's proposed participation requirements, which were not protested, and declined to spill more ink on how those participation requirements comported with Commission precedent.

c. Governance

SPP set forth its proposed governance structure for the WEIS Market in the WMEC Charter, which SPP filed as part of the WEIS Market Tariff. All major governance decisions would be made through the WMEC, which would have the authority to approve or reject proposed amendments to the tariff or market rules, to recommend amendments to the WJDA, and to advise SPP on other market rule

148. WEIS Market Order, *supra* note 140, at P 8.
149. *Id*. at P 9.
150. *Id*.
151. *Id*. at P 11.
152. WEIS Market Order, *supra* note 140, at P 11.
153. *Id*. at PP 20–21.
154. *Id*. at P 7.
155. *Id*.

changes.[156] Each WEIS Market participant would have one representative on the WMEC. The WMEC would use a "house and senate" approach to voting; for a resolution to be approved it would typically need to receive both "(1) an affirmative vote of at least 75% with the WMEC representative votes weighted by the total net energy for load of WEIS Participants; and (2) an affirmative vote of at least 75% of WMEC representatives."[157] The WMEC would meet biannually, at minimum, and all meetings would be noticed and open to the public unless a specific vote required confidentiality.[158]

SPP also designed a governance system that would allow a broad collection of non-utility stakeholders to participate. For example, any state with a resource or load participating in the WEIS Market would be empowered to designate a state liaison to attend the WMEC in an advisory role.[159] SPP claimed that its "WEIS Revision Request" process would allow "any interested party to meaningfully participate" in WEIS Market governance.[160]

The SPP independent market monitor (SPP MMU) would monitor the WEIS Market.[161] Furthermore, the results of a Market Power Study that the SPP MMU had completed before the WEIS Market proposal was finalized informed mitigation provisions that were incorporated into the WEIS Market Tariff.[162]

Some commenters expressed support for the proposed governance structure, arguing that it would be broadly inclusive and align with existing governance frameworks for public power utilities.[163] Other stakeholders disagreed. One utility, for example, argued that the voting structure was unduly discriminatory because it provided disproportionate representation to a federal power administration over public utilities with several affiliates.[164] A coalition of public interest organizations argued that the WMEC Charter unreasonably limited voting to WEIS Market participants and unreasonably excluded "entities that have no direct financial interest in the operation of the WEIS Market."[165] In response, SPP explained that the WMEC—modeled on SPP's Market and Operations Policy Committee—provided sufficient transparency to all stakeholders.[166]

156. WEIS Market Order, *supra* note 140, at P 52.

157. *Id*. at P 53.

158. *Id*. at n.90.

159. *Id*. at P 54.

160. WEIS Market Order, *supra* note 140, at P 54 ("Entities that may submit a Revision Request are: (1) any WJDA signatory; (2) any staff member of a governmental authority having jurisdiction over the WEIS Market or any WEIS Participant; (3) SPP staff; (4) any rostered individual of an official WMEC organizational group; (5) any entity designated by a qualified entity to submit a Revision Request "on their behalf"; (6) a WEIS Participant; (7) SPP Western Transmission Customers or other entities that are parties to transactions under the WEIS Tariff; and (8) the SPP MMU. SPP notes that this will allow any interested party to meaningfully participate in the governance of the WEIS Market.").

161. *Id*. at P 10.

162. *Id*.

163. *Id*. at P 55.

164. WEIS Market Order, *supra* note 140, at P 56.

165. *Id*. at P 57.

166. *Id*. at P 60.

FERC approved the proposed WEIS Market governance framework, determining that limiting voting rights to WJDA signatories was reasonable "because only WJDA signatories have made a financial commitment to the WEIS Market."[167] The Commission noted, however, that any party could receive voting rights on the WMEC by executing a WJDA.[168] The Commission also found that SPP's WMEC Charter would provide adequate opportunity for stakeholders who do not execute WJDAs to participate in WMEC open meetings, engage in the Revision Request process, and appeal to SPP's Board of Directors any WEIS Market matter of concern.[169]

Regarding market power mitigation, one utility argued that SPP's proposed Market Power Study would not be adequate to address anticipated market concentration and potential pivotal suppliers in the WEIS Market.[170] FERC disagreed, determining that SPP's proposed monitoring scheme would address the major market power issues that SPP's MMU identified and allow SPP to mitigate "resources with local and structural system-wide market power" as necessary.[171] FERC also noted that although the market monitoring scheme for the WEIS Market resembled SPP's existing monitoring regime, it appropriately applied more stringent mitigation thresholds because the "smaller, more concentrated" WEIS Market might offer greater opportunities to exercise market power.[172]

d. Pricing

SPP proposed that it would calculate each WEIS Market participant's imbalance energy within the market footprint every five minutes and would settle the market by calculating LMPs for each area.[173] SPP adopted an earlier suggestion by the Commission that it add a marginal loss component to its calculated LMPs and incorporate marginal losses into its market software.[174] One utility protested SPP's pricing proposal, arguing that SPP had not proved that transactions on its system would reflect marginal losses accurately.[175] FERC determined in accepting SPP's pricing proposal that its framework—including accounting for marginal losses through its pricing and dispatch algorithms—was just, reasonable, and responsive to the Commission's earlier guidance. More specifically, the Commission found that the use of marginal losses would ensure least-cost dispatch, "minimize imbalance costs, provide prices that accurately reflect marginal costs, and preserve resources' incentives to follow dispatch."[176]

167. *Id*. at P 66.
168. WEIS Market Order, *supra* note 140, at P 66.
169. *Id*. at P 67.
170. *Id*. at P 71.
171. *Id*. at P 69.
172. WEIS Market Order, *supra* note 140, at P 80.
173. *Id*. at P 8.
174. *Id*. at P 85.
175. *Id*. at P 86.
176. WEIS Market Order, *supra* note 140, at P 89.

e. Transmission Service

SPP proposed to constrain dispatch of the WEIS Market to the amount of transmission capacity that market participants made available to be used for Joint Dispatch Transmission Service (JDTS).[177] In its initial filing, which FERC had rejected, SPP had not clearly explained how it would ensure that JDTS was not provided over the transmission capacity of non-participating entities in violation of the requirements of Order Nos. 890 and 890-A.[178] In its revised proposal, SPP clarified that it would not only restrict its dispatch of resources to transmission paths made available by market participants, but also that SPP would create and maintain constraints in its models to reflect this limited transmission capacity.[179] To facilitate this modeling, SPP proposed that JDTS providers would be required to communicate to SPP the transmission capacity that they would make available to the WEIS Market and that the WEIS Market's dispatch would not use non-participants' transmission rights.[180] SPP's revised proposal noted that JDTS would be provided at a rate of $0/MWh.[181]

Some commenters argued that SPP's proposal, even as revised, would not protect non-participants sufficiently from uncompensated use of their transmission rights.[182] One utility requested that FERC direct SPP to report on WEIS Market transactions and demonstrate that JDTS transactions did not displace other transmission service.[183] Another argued that the WEIS Market could create loop flow—a situation where increases in generation could create flows of electrons on unscheduled paths.[184]

FERC noted in approving the WEIS Market that SPP's solution would constrain transmission flows explicitly to the capacity that market participants designated as available and would respect the transmission rights of non-participants.[185] The Commission also disagreed that potential loop flows warranted rejection or modification of SPP's proposal.[186] Citing to its own precedent, FERC explained that "changes to market operations may indeed result in changes to flows on the integrated transmission system[;] [t]his, however, is not reason to prevent im-

177. *Id*. at P 8.

178. *Id*. at P 101.

179. *Id*. at P 102.

180. WEIS Market Order, *supra* note 140, at P 102.

181. *Southwest Power Pool*, Submission of Western Energy Imbalance Service Market Tariff, Western Joint Dispatch Agreements, and the Western Markets Executive Committee Charter, FERC Docket No. ER21-3-000 at 29 (Oct. 1, 2020).

182. WEIS Market Order, *supra* note 140, at P 106.

183. *Id*. at P 108.

184. *Id*. at P 112.

185. *Id*. at P 124.

186. WEIS Market Order, *supra* note 140, at P 106.

provements to market operations that will result in increased efficiencies and benefits to customers."[187] The Commission also declined to impose new reporting requirements.[188]

B. Enhanced Bilateral Energy Markets

Concurrently with the creation of imbalance markets in the West and Southwest, utilities in the Rocky Mountain and Southeast regions of the country began to develop frameworks that could enhance bilateral trading of short-term energy within their regions.

1. PSCo Joint Dispatch Agreement

PSCo, in late 2014, filed a proposal to implement joint dispatch service to facilitate the centralized, intra-hour dispatch of resources within its BAA and across the transmission systems of three utilities: PSCo; Black Hills/Colorado Electric Utility Company, LP; and Platte River Power Authority (Platte River).[189] FERC rejected PSCo's initial proposal in June of 2015, finding that it could have resulted in excessive costs and that it included insufficient protections against both the exercise of market power and possible violations of the Commission's Standards of Conduct.[190]

PSCo filed a revised proposal in October of 2015, in which it explained that the three parties had renegotiated the JDA to address the Commission's concerns.[191] PSCo's revised proposal explained that the JDA was representative of a long-standing interest in development and participation in a broader energy market, and that, for some time, the utility had sought the efficiency benefits of integrated regional market operations.[192] The proposal clarified that the JDA was not a commitment agreement, but that it would implement a more efficient mechanism for providing imbalance energy among the parties.[193]

Prospective JDA participant Platte River expressed support for the proposal, but another PSCo transmission customer raised concerns, arguing that the JDA and PSCo's JDTS together comprised a loose power pool and that PSCo had not proposed the types of transmission rate measures that Order No. 888 requires for

187. *Id*. (citing 147 FERC ¶ 61,231, at P 268).

188. *Id*. at P 130.

189. *Public Service Company of Colorado & Black Hills/Colorado Electric Utility Company, LP*, 151 FERC ¶ 61,248 at P 2 (2015).

190. *Id.* at P 1.

191. *Public Service Company of Colorado & Black Hills/Colorado Electric Utility Company, LP*, 154 FERC ¶ 61,107 at P 5 (2016) [hereinafter Order Accepting PSCo JDA].

192. *Id.* at P 6.

193. *Id.* at P 7.

a power pool, such as a joint OATT.[194] The customer called on FERC to distinguish the JDA from other energy imbalance markets, such as CAISO's EIM.[195]

FERC disagreed with this protest, finding that PSCo's proposal did not establish a loose power pool and that the requirements of Order No. 888, accordingly, did not apply.[196] The Commission accepted PSCo's revised JDA and the associated tariff revisions to implement JDTS, explaining that the structure would enable participants to realize "substantial cost savings" by dispatching their collective resources more efficiently and on a least-cost basis.[197] FERC explained that PSCo had addressed its prior concerns adequately and that the passing through of cost savings to the utilities' customers would not affect third parties adversely.[198]

a. Market Structure & Operational Control

The proposed JDA contemplated that each party would continue to commit certain generation resources and operating reserves—either its own or by contract—to meet its native load requirements.[199] JDA parties would "determine how much or how little of their resources to make available for dispatch under the JDA" and no control would be conferred over a party's non-dispatchable units.[200] Under the JDA, the transacting parties would pay each other directly for energy transactions, but PSCo would operate the settlement process and issue invoices to each party.[201] JDA transactions generally would not be tagged like other energy transactions because the Western Electricity Coordinating Council already monitored transmission on the western grid. Where the Joint Dispatch Energy sales could create loop flows, however, PSCo would tag transactions.[202]

FERC approved the market structure, explaining that although the JDA would allow for the real-time dispatch of resources on a least-cost basis and could therefore replace some energy imbalance transfers, the JDA did not replace energy imbalance service altogether because it did not include scheduled transmission service.[203]

194. *Id.* at PP 38, 41; *see Id*. at P 38 n.58 (noting that the protester cited in support of its arguments to Order No. 888. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC STATS. & REGS. ¶ 31,036, at 31,728 (1996) [hereinafter Order No. 888], *order on reh'g*, Order No. 888-A, FERC STATS. & REGS. ¶ 31,048 [hereinafter Order No. 888-A], *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom.* Transmission Access Pol'y Study Grp. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.* N.Y. v. FERC, 535 U.S. 1 (2002)).

195. Order Accepting PSCo JDA, *supra* note 191, at P 40.

196. *Id.* at P 85.

197. *Id.* at PP 81, 87.

198. *Id.*

199. Order Accepting PSCo JDA, *supra* note 191, at P 7.

200. *Id.* at PP 8–9.

201. *Id.* at P 16.

202. *Id.* at P 17.

203. Order Accepting PSCo JDA, *supra* note 191, at PP 41, 87.

b. Participation

To participate in the JDA, an entity needed to: "(1) be a load serving entity within the PSCo BAA; (2) execute the Joint Dispatch Agreement with each participating transmission provider; (3) offer generating resources that meet dispatch criteria into the Joint Dispatch Agreement pool; and (4) secure an agreement with its host transmission provider to provide corresponding non-firm zero-rate transmission service for use by other Parties to the Joint Dispatch Agreement."[204] If a load-serving entity operating in the PSCo BAA does not serve as its own transmission provider, it may still participate in the JDA by committing to contribute its generating resources to the JDA pool and making arrangements with its host transmission provider to provide reciprocal JDTS.[205]

One utility criticized PSCo's proposed participation requirements, arguing that it is unreasonable to require a utility to pay for transmission facilities used to provide JDTS when it cannot unilaterally elect to take JDTS itself as an existing PSCo transmission customer.[206]

In accepting PSCO's proposal, FERC noted that the JDA "allows any entity to join, provided … it makes arrangements with its transmission provider to have access to unused Available Transfer Capability [] at a zero dollar rate."[207] The Commission found this condition not to be "unduly burdensome, as it would not bar participation by any entity that seeks to receive the cost savings benefits" of the JDA.[208] Instead, the Commission noted that any prospective participant that is an existing customer of the JDA parties could participate by executing the JDA and electing to receive the JDTS that these parties had already agreed to provide.[209]

c. Governance

PSCo's proposal did not establish a formal system of governance for the JDA or the provision of JDTS, but instead established a set of audit rights and transparency provisions that PSCo claimed would enable JDA parties to access unit cost information.[210] In a supplemental filing, PSCo clarified that each JDA party would contribute two employees to an Audit Committee that would periodically review the JDA and audit JDA operations.[211] The JDA also would empower any party to audit the records of any other party "to the extent reasonably necessary to verify the accuracy of any statement, charge, or computation."[212]

204. *Id.* at P 22.
205. *Id.* at P 18.
206. *Id.* at P 39.
207. Order Accepting PSCo JDA, *supra* note 191, at P 85.
208. *Id.*
209. *Id.*
210. *Id*. at P 69
211. Order Accepting PSCo JDA, *supra* note 191, at P 69.
212. *Id.* at P 19.

PSCo clarified that the Parties would create a web-based portal through which each JDA participant would submit production cost information for its resources.[213] The portal would be designed to ensure that each party's dispatch date remained confidential and that PSCo personnel involved in marketing PSCo's own energy would not have access to other parties' cost information.[214] One utility argued that PSCo marketing function employees might still be able to access the non-public cost information of its competitors, despite the portal structure, and use that information to obtain an unfair advantage in the bilateral energy market.[215]

FERC did not make a determination specifically on the governance of the JDA, nor did it address the Audit Committee in its findings, but FERC agreed with PSCo that the use of a web-based portal would prevent PSCo employees from accessing non-public information.[216] The Commission also noted that PSCo had committed to implement additional physical and cyber safeguards to protect non-public information.

d. Pricing

Energy prices under the JDA would be determined after transactions are completed and energy is delivered within the PSCo BAA.[217] The JDA outlined three energy products: (1) Joint Dispatch Energy, (2) Deficit Energy, and (3) Surplus Energy.[218] Each would be priced differently. JDA participants would also pay a $0.50/MWh management fee to PSCo for providing each service.[219]

First, PSCo contemplated that most energy transactions under the JDA would be for Joint Dispatch Energy, a service that would be priced on a per-MWh basis at the system-wide marginal price and calculated hourly.[220] Joint Dispatch Energy pricing, like traditional energy pricing, would be based on the marginal unit's incremental fuel cost plus any non-fuel variable operations and maintenance costs.[221] Because PSCo at the time of filing the JDA did not have market-based rate (MBR) authority in the PSCo BAA, the JDA also proposed to apply a cost-based price cap to any payments that JDA participants would make to PSCo for Joint Dispatch

213. *Id.* at P 20.

214. *Id.*

215. Order Accepting PSCo JDA, *supra* note 191, at PP 75, 77.

216. *Id.* at P 83.

217. *Id.* at P 10.

218. *Id.*

219. Order Accepting PSCo JDA, *supra* note 191, at PP 14-15; *see id.* at P 15 nn.23-24 ((citing *Commonwealth Edison Co.*, 35 FERC ¶ 61,352 (1986)) (for the proposition that the Commission has historically allowed the use of adders for the recovery of transmission costs related to purchase and resale service) and (citing *Terra Comfort Corp.*, 52 FERC ¶ 61,241, at p. 61,840 (1990); *Indiana & Michigan Electric Co.*, 12 FERC ¶ 61,167 (1980); *Niagara Mohawk Power Corp*., 86 FERC ¶ 61,009, at p. 61,028 (1999)) (for the proposition that the Commission has allowed percentage adders for generating entities to recover incremental energy costs)).

220. *Id.*

221. *Id.* at P 10.

Energy.[222] PSCo clarified that the price for Joint Dispatch Energy would never be negative.[223]

Second, if a JDA party's internal resources were insufficient to meet its hourly energy requirements, it could purchase Deficit Energy from PSCo at a rate of the marginal variable cost of supplying that energy plus an adder, which would be the greater of $10/MWh or 10 percent of PSCo's costs for providing the Deficit Energy.[224] This higher price was designed to incentivize participants not to plan to outsource its resource adequacy responsibilities to other JDA participants.

Third, the JDA would allow any party to sell Surplus Energy to PSCo when its generation produces energy in excess of its hourly energy requirements. The rate for Surplus Energy would be set at the system marginal price minus $1/MWh to discourage excessive over-production of energy.[225]

One utility criticized PSCo's pricing proposal, arguing that charging JDA participants a negotiated, "non-cost justified penalty" for requiring Deficit Energy or selling Surplus Energy in lieu of assessing the standard energy imbalance charges for those transfers under the existing PSCo OATT is not just and reasonable.[226] The utility argued that PSCo's proposed cost-based cap for its energy sales did not mitigate market power concerns sufficiently.[227]

FERC accepted PSCo's proposed pricing framework, finding specifically that PSCo's proposal to cap payments for its energy sales at the utility's existing cost-based price cap reasonably addressed the Commission's earlier concerns about PSCo's potential to exercise market power.[228] The Commission also rejected concerns that the rate for deficit energy represented a "non-cost justified penalty," finding that the price for deficit energy was based on the actual cost of providing such service.[229]

e. Transmission Service

PSCo proposed that JDTS would be a non-firm, intra-hour transmission service provided only on an "as-available" basis.[230] The service would use unreserved transmission and would have a lower priority than any other transmission

222. *Id*. at P 11 (citing *Xcel Energy Services, Inc*., 117 FERC ¶ 61,180 at P 38 (2006)).

223. Order Accepting PSCo JDA, *supra* note 191, at P 10.

224. *Id.* at P 12.

225. *Id*. at P 13 (citing *Carolina Power & Light Co.*, 95 FERC ¶ 61,429, at p. 62,597 (2001); *Algonquin Gas Transmission, LLC*, 115 FERC ¶ 61,067 (2006)) (for the proposition that penalties are not cost-based and therefore cost-based support is not required).

226. *Id.* at P 45.

227. Order Accepting PSCo JDA, *supra* note 191, at P 47.

228. *Id.* at P 82.

229. *Id.* at P 87.

230. *Id.* at P 21.

service, meaning that service could be interrupted.[231] PSCo explained that its proposed JDTS rate of $0/ MWh would represent the true opportunity cost of using transmission that would otherwise go unused—that is, zero.[232]

PSCo also cited to earlier Commission decisions on the CAISO EIM to support its zonal, *i.e.,* "license-plate," transmission service for imbalance energy.[233] Although the service would have no nominal cost, PSCo noted that JDA parties must provide reciprocal transmission service as a condition of joining the JDA, an arrangement that PSCo also claimed FERC had approved previously as a form of in-kind compensation.[234]

Critics commented that PSCo's pricing of JDTS at $0/MWh would erode other non-firm transmission service and would deprive PSCo's other transmission customers of revenue credits by serving as an improper subsidy for JDA participants.[235] One utility argued that PSCo's proposal to offer zero-dollar transmission service did not align with the Commission's policy of allowing for discounted transmission service only when a discount is required to increase throughput or when it is necessary to avoid rate pancaking and the distortion of competitive bids.[236]

FERC disagreed, determining that a zero-dollar rate for JDTS was just and reasonable when the transmission service is used as part of the JDA.[237] The Commission explained that JDTS makes available only transmission capacity that was not committed through either the firm or non-firm reservation processes. Because the transmission would otherwise go unused, FERC agreed that JDTS presents no opportunity cost and thus a zero-dollar rate is justified.[238] FERC also explained that because the use of JDTS is limited to energy imbalance transfers that result

231. Order Accepting PSCo JDA, *supra* note 191, at P 21.

232. *Id.* at P 23.

233. *Id.* at P 35 (citing *PacifiCorp*, 147 FERC ¶ 61,227 at P 146 (2014)).

234. *Id*. (citing Ctr. Iowa Power Coop., Inc. v. FERC, 606 F.2d 1156, 1172 (D.C. Cir. 1979)). FERC determined in *Ctr. Iowa Power* that "reciprocal transmission" could be required of power pool members and that each participant could provide such reciprocal transmission either "in kind," i.e., by donation of transmission capacity for use by the pool, or "in money," by paying for the value of the transmission service required. *Ctr. Iowa Power Coop., Inc.*, 606 F.2d 1156, 1170 at n. 46. In *Ctr. Iowa Power*, the D.C. Circuit evaluated whether FERC erred in finding that the membership requirements of a 31-member Mid-Continent Area Power Pool (MAPP) were discriminatory and accepting the MAPP membership agreement only with modified membership conditions. In finding that the Commission had not erred, the court upheld the modified conditions as based on substantial evidence. One such modified condition rejected a MAPP proposal to relegate small utility systems to "associate participant" status on the basis of those systems' being too small to "to reciprocate in kind for the short-term transmission services" that would be used to facilitate MAPP. FERC determined in its order accepting the MAPP membership agreement that as long as these smaller utilities "can provide compensation for the true value of this transmission service, whether in kind or money," their obligation to provide reciprocal transmission service should be considered satisfied. *Id.*

235. Order Accepting PSCo JDA, *supra* note 191, at P 84.

236. *Id*. at PP 38, 40.

237. *Id*. at P 84.

238. *Id*.

from least-cost dispatch under the JDA, it does not serve as a substitute for typical non-firm transmission service for bilateral transactions.[239]

FERC found protesters' reliance on SPP precedent to be "misplaced."[240] The Commission explained that its acceptance of a prior SPP proposal "did not preclude zero-cost transmission in these circumstances, and further, transmission service at zero cost was not at issue in SPP."[241]

2. Southeast Energy Exchange Market

Fourteen Southeast utilities, in February 2021, filed a proposal to establish SEEM, which the filing parties described as a "new voluntary electronic trading platform designed to enhance the existing bilateral market in the Southeast" by using surplus transmission capacity.[242] SEEM was designed to match bidders and offerors on a 15-minute basis; matched pairs would transact with each other under existing bilateral agreements.[243] SEEM transactions would take place over available transmission capacity using a new lowest-priority, zero-dollar transmission service called Non-Firm Energy Exchange Transmission Service (NFEETS), a service that SEEM participants would be required either to provide over their own transmission systems or to arrange to take from their local transmission provider.[244] These parameters were outlined in a contractual document—the "SEEM Agreement."[245]

Commenters raised a series of concerns with the SEEM proposal, arguing that the market's structure, participation requirements, governance framework, and proposed transmission service were unjust and unreasonable.

After FERC staff issued two deficiency letters to seek more information from the SEEM filing parties, the Commission elected not to issue an order by the statutory deadline. Instead, the Commission Secretary released a notice on October 13, 2021, that the proposal had gone into effect by operation of law (BOL Notice).[246] The BOL Notice was accompanied by statements from Chairman Richard Glick and each of the other then-sitting FERC Commissioners.[247] In November 2021, the Commission issued a substantive order that solely accepted the tariff

239. Order Accepting PSCo JDA, *supra* note 191, at P 84.

240. *Id*. at P 86.

241. *Id.*

242. *Alabama Power Co.*, Southeast Energy Exchange Market Agreement, FERC Docket No. ER21-1111 at 1–2 (Feb. 12, 2021) [hereinafter SEEM Proposal].

243. *Id*. at 2, 4.

244. *Id*.

245. *See generally id.*

246. *Alabama Power Co.*, Notice of Filing Taking Effect by Operation of Law, FERC Docket Nos. ER21-1111 et al. (Oct. 13, 2021) [hereinafter BOL Notice].

247. *See* 16 U.S.C. § 824(d)(g) (Congress in 2018 added section 205(g) to the Federal Power Act. Section 205(g) provides that inaction by the Commission that allows a rate change to take effect shall be considered an order for purposes of rehearing and judicial review. Section 205(g)(1)(B) requires each Commissioner to submit a statement whenever a rate takes effect by operation of law that explains the views of the Commissioner with respect to the change).

revisions necessary to implement NFEETS (NFEETS Order).[248] FERC issued several further orders denying rehearing of these Commission decisions, including an order in December 2021 that rejected requests for rehearing on the BOL Notice as untimely[249] and two orders issued concurrently in March 2022: one that denied rehearing of the December 2021 rejection order[250] and another that modified the Commission's rationale for denying rehearing of the NFEETS Order.[251]

Several protesters appealed the Commission's decision to the D.C. Circuit. The D.C. Circuit determined that FERC had failed to respond adequately to protests of the SEEM proposal.[252] The court vacated and remanded the NFEETS Order and remanded several related SEEM decisions without vacatur so that FERC could address protesters' concerns more thoroughly.[253]

As of May 2024, FERC had again declined to issue an order addressing protests of the SEEM Proposal and several protesters had again petitioned the D.C. Circuit for review of that decision.[254] In June 2024, however, FERC issued an order seeking further briefing to assist the Commission in addressing the D.C. Circuit's remand directives.[255] FERC established a schedule whereby initial briefs would be due on August 13, 2024, and reply briefs would be due on September 12, 2024. As of the date of this article's publication, the SEEM proceeding remained pending before the Commission, following the submission of an initial brief by the SEEM filing parties and three reply briefs, among other pleadings.

Although several SEEM-related orders remain vacated until the D.C. Circuit issues another opinion, SEEM reflects another flavor of non-RTO organized market that provides a useful comparison to its Western and Southwestern counterparts. Accordingly, a summary of the SEEM proposal and the reception it received from stakeholders, FERC, and the D.C. Circuit are included below.

a. Market Structure & Operational Control

SEEM was proposed to be a "region-wide, intra-hour market platform to facilitate bilateral trading between voluntary market participants that will utilize unused transmission capacity to achieve cost savings throughout the region."[256] SEEM would use an algorithm to "match" participant bids and offers for each

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248. *Duke Energy Progress, LLC*, 177 FERC ¶ 61,080 at P 1 (2021) [hereinafter NFEETS Order]; *Duke Energy Progress, LLC,* 178 FERC ¶ 61,195 at P 1 (2022).

249. *Alabama Power Co.*, 177 FERC ¶ 61,178 at P 1 (2021).

250. *Alabama Power Co.*, *Order Addressing Arguments Raised on Rehearing*, 178 FERC ¶ 61,196 at P 2 (2022).

251. *Duke Energy Progress, LLC*, 178 FERC ¶ 61,195 at P 2 (2022).

252. Advanced Energy United, Inc. v. FERC, 82 F.4th 1095, 1117 (D.C. Cir. 2023) [hereinafter D.C. Circuit Remand Order].

253. *Id*.

254. *See* Adv. Energy United et. al. v. FERC, Joint Petition for Review, D.C. Circuit Case No. 23-1341 (Dec. 18, 2023) [hereinafter Joint Petition for Review].

255. *Alabama Power Co*., 187 FERC ¶ 61,174 at P 53 (2024) ("We find that supplementing the record would allow the Commission to appropriately address the D.C. Circuit's remand directives, including the directive to address the rehearing requests of the Deadlock Order.").

256. SEEM Proposal, *supra* note 242, at 4.

fifteen-minute trading period into paired transactions that would be priced at the midpoint between the bid and the offer, adjusted for losses.[257] "Energy Exchanges," the fifteen-minute transfers of imbalance energy from seller to buyer, would be delivered over the zero-cost NFEETS that SEEM participating transmission providers make available.[258]

The filing parties explained that many prospective SEEM participants already transacted with each other bilaterally and that FERC had found the existing bilateral market—i.e., sales made pursuant to entities' MBR authority—to be just and reasonable.[259] Transactions through the preexisting bilateral market in the Southeast were typically made on an hourly basis, however, whereas SEEM would allow for shorter, intra-hour transactions and more efficient price discovery.[260]

Commenters criticized the SEEM proposal on several grounds, including arguing that the overall market structure constituted a loose power pool that did not comply with FERC's requirements for power pools,[261] that the structure would allow participants to act anti-competitively,[262] and that SEEM would fall short in several areas of the Commission's standards for RTO/ ISOs and other organized markets.[263]

As noted above, FERC failed to issue an order either accepting or rejecting the SEEM proposal by the statutory deadline. The tariff provisions that would establish SEEM therefore became effective by operation of law as of October 12, 2021.[264]

The D.C. Circuit, in its opinion addressing the NFEETS Order as well as FERC's non-decisions on the overall SEEM proposal, found that the Commission had properly concluded that the record in the SEEM proceeding "demonstrated that SEEM's structure disincentivizes" anticompetitive behavior."[265] The Court remanded several components of SEEM, however, for further consideration by FERC.

b. Participation

The filing parties proposed several distinct roles for participants in SEEM, including "Members" and "Participants."[266] "Members" would be those founding entities of SEEM who had both signed onto the market proposal and agreed to fund, collectively, the market's upfront and ongoing costs.[267] Membership would

257. *Id*.

258. *Id*.

259. *Id*. at 5.

260. SEEM Proposal, *supra* note 242, at 9.

261. *See, e.g.*, *Motion to Intervene & Limited Protest & Comment of Public Interest Organizations.*, FERC Docket Nos. ER21-1111 et al. at 8-10 (Mar. 15, 2021) [hereinafter PIOs Initial Protest].

262. *Id*. at 74.

263. *Id*. at 18.

264. *See generally* BOL Notice, *supra* note 246.

265. D.C. Circuit Remand Order, *supra* note 252, at 1111.

266. SEEM Proposal, *supra* note 242, at 15.

267. *Id*.

be open, on a going-forward basis, to any entity that was: "(i) a Load Serving Entity located in the [SEEM] Territory; (ii) an Association, Cooperative or Governmental Entity that is a Load Serving Entity located in the Territory; or (iii) an Association, Cooperative or Governmental Utility created for the purpose of providing Energy to a Cooperative or Governmental Load Serving Entities (or the Load Serving Entities being served by an Association, Cooperative or Governmental Entity) located in the Territory."[268] Any future Member also must agree to the membership conditions outlined in the SEEM Agreement.[269]

"Participants" would be those entities that submit bids and offers to be matched through SEEM into energy *exchanges*.[270] Any entity may become a Participant by: (i) owning—or otherwise controlling—a source or sink within the SEEM footprint; (ii) executing a Participation Agreement, included as an attachment to the SEEM Agreement; (iii) arranging to take NFEETS from each participating transmission provider; and (iv) entering into contractual "enabling agreements"—contracts to facilitate bilateral trading—with at least three other SEEM Participants.[271] Regardless of an entity's membership status, Members and Participants would participate in SEEM "on exactly the same terms."[272] SEEM would not require minimum participation terms for Members or Participants and each could withdraw from the market after giving written notice.[273]

Some commenters criticized SEEM's proposed participation requirements, arguing that they unreasonably barred participation by certain types of generators—including independent power producers—and that limited participation could hinder the deployment of renewable energy resources in the Southeast.[274]

FERC's failure to act to reject the SEEM proposal by the statutory deadline resulted in acceptance of the SEEM participation requirements by operation of law.

The D.C. Circuit agreed, at least in part, with commenters who raised similar arguments in their petition for review of FERC's acceptance of SEEM, characterizing petitioners' arguments as "not without some merit" and noting that petitioners' "expert affidavit explained numerous ways SEEM's participation requirements could be manipulated by a Member acting in its own monopoly interests."[275] The court ultimately determined, nevertheless, that the petitioners had failed to demonstrate that FERC had acted arbitrarily and capriciously or had "'altered the

268. *Id*.
269. *Id*.
270. SEEM Proposal, *supra* note 242, at 16.
271. *Id*.
272. *Id*.
273. *Id*. at 20.
274. *See, e.g.*, PIOs Initial Protest, *supra* note 261, at 50. "The SEEM Market Rules require that a Participant '[o]wn or otherwise control a Source within the Territory and/or be contractually obligated to serve a Sink within the Territory.' It is not clear that independent power producers could meet this criteria [sic]."
275. D.C. Circuit Remand Order, *supra* note 252, at 1111.

burden of proof' in determining that SEEM's participation requirements were not unduly discriminatory."[276]

c. Governance

The filing parties claimed that SEEM's governance structure would "respect[t] and recogniz[e] the diverse Member interests" and would provide sufficient transparency into SEEM transactions to both participating and non-participating stakeholders.[277] As proposed, the SEEM governance framework consisted of a Membership Board, which would be responsible for all significant issues, and an Operating Committee, which would oversee the day-to-day functioning of the SEEM system.[278] The filing parties also proposed to retain a third-party Auditor to "ensur[e] that the [SEEM] system functions properly"[279] and noted that Members would hold annual meetings that would be open to all interested parties.[280]

The Membership Board would be composed of Member representatives and each representative would have two votes: a popular vote and a weighted vote based on net energy load.[281] Approval of proposals by the board would require a combined majority of the popular vote and either a majority or a super-majority of the weighted vote, depending on whether the proposal was considered a "general matter" or a "significant matter," respectively.[282]

The Operating Committee would be composed of four committee members, with each holding a single, equal vote and each representing one of four sectors: two voting members representing investor-owned utilities, one representing cooperatives, and one representing governmental utilities.[283] A proposal before the Operating Committee would need to receive unanimous support from the committee members to be approved.[284] Furthermore, all Members would "have a right to attend, observe, and participate in Operating Committee meetings," although only committee members would vote on proposals.[285]

Several parties criticized the SEEM governance framework. One coalition argued both that the governance structure "create[d] opportunities for specific applicants to control and manipulate the market" and that the framework unreasonably excluded non-Participant stakeholders from meaningfully engaging in decision-making around market rules.[286] Another coalition called for the Commission to "address membership and governance shortcomings" of the SEEM proposal,

276. *Id*.
277. SEEM Proposal, *supra* note 242, at 21.
278. *Id*.
279. *Id*. at 18.
280. *Id*. at 23.
281. SEEM Proposal, *supra* note 242, at 21.
282. *Id*. at 21-22.
283. *Id*. at 22.
284. *Id*.
285. SEEM Proposal, *supra* note 242, at 22.
286. PIOs Initial Protest, *supra* note 261, at 28.

arguing that the proposed governance framework "excludes whole classes of interested parties from any participation in governance" and "allows for control entirely by vertically integrated utilities."[287]

In response to these protests and FERC staff's first deficiency letter, the filing parties proposed certain modifications to the SEEM governance framework. Although they did not modify the core structure of the Membership Board and Operating Committee, the filing parties indicated that they would submit confidential data to FERC on a weekly basis and would increase transparency regarding the role of the Market Auditor, including by requiring the Market Auditor to disclose its reports to market participants.[288]

FERC in declining to act on the SEEM Agreement also declined to comment substantively on the proposed governance framework for SEEM.

Although the D.C. Circuit opinion notes that the SEEM Agreement outlines governance procedures for SEEM, the court also declined to make any specific findings on the legality of SEEM's proposed governance framework in its order remanding the SEEM proceeding to FERC for further consideration.[289] The court may, however, make substantive determinations surrounding SEEM's governance structure if it takes up petitioners' second petition for review, which is currently pending before the court.[290]

d. Pricing

Transactions matched through SEEM would be priced on a "split-the-savings" basis, meaning that "the transaction price [would] reflect the midpoint between the seller's offer price and the buyer's bid price, with an adjustment for losses."[291] Losses, which would be reflected financially, would be allocated evenly between the two transacting parties.[292] The settlement of transactions would occur bilaterally.[293] Furthermore, prices for Energy Exchanges would be cost-capped, where applicable, so that market participants would not collect revenues in excess of their existing MBR authorizations.[294]

Commenters largely expressed ambivalence about SEEM's proposed pricing structure. One party, for example, noted that "the split-savings pricing proposal

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287. *Advanced Energy Econ. et al.,* Comments of Advanced Energy Economy, Advanced Energy Buyers Group., Renewable Energy Buyers Alliance, and the Solar Energy Industry Association, FERC Docket Nos. ER21-1111 et al. at 19 (Mar. 15, 2021) [hereinafter Clean Energy Coalition Comments].

288. *Alabama Power Co.,* Response to Deficiency Letter, FERC Docket Nos. ER21-1111 et al. at 3 (June 7, 2021).

289. *See* D.C. Circuit Remand Order, *supra* note 252, at 1103.

290. *See generally* Joint Petition for Review, *supra* note 254; *but see* Renewed Motion of Respondent Federal Energy Regulatory Commission to Hold Appeal in Abeyance and Suspend Filing of the Certified Index to the Record, D.C. Cir. No. 23-1341 (filed June 15, 2024) (requesting that the D.C. Circuit again hold its proceeding in abeyance pending FERC action pursuant to its request for further briefing on several issues action pursuant to its request for further briefing on several issues related to SEEM's Compliance with Order No. 888).

291. SEEM Proposal, *supra* note 242, at 4.

292. *Id*. at 28.

293. *Id*. at 10.

294. *Id*.

[is] largely a reflection of current price formation" for bilateral transactions in the Southeast.[295] The same party argued that although "the proposed split-savings model is [not] unjust or unreasonable per se, it is generally thought to be inefficient when compared to other pricing models."[296] FERC in declining to act on the SEEM Agreement also declined to comment substantively on SEEM's proposed pricing methodology.

The D.C. Circuit also declined to opine on SEEM's proposed midpoint pricing. The court may have implicitly blessed the practice, however, when it noted that although two-thirds of the U.S. population is served by RTO/ISOs, which use auctions to set a single clearing price for energy at each location, "traditional markets still exist," within which primarily vertically integrated utilities "sometimes use short-term transactions to purchase energy from another utility" when it is economic.[297] Furthermore, Judge Rao, in a partially-concurring opinion, noted that the SEEM "algorithm matches eligible buyers and sellers at 15-minute increments, pricing transactions at the midpoint between the offer price and the bid price," but that the algorithm serves only a matching function; the participants consummate each transaction under separate contractual agreements to enable bilateral trading.[298]

e. Transmission service

Concurrently with their filing of the SEEM Agreement at FERC, each prospective SEEM Member that serves as a transmission provider and maintains an OATT filed an amendment to that OATT to reflect its intent to offer NFEETS.[299]

Describing NFEETS as a new "non-firm product, provided on an as-available basis for the sole purpose of facilitating Energy Exchanges," the filing parties explained that it would have the lowest priority of all transmission services.[300] More specifically, NFEETS would be available only on an "as-available basis," meaning that it would only be offered into SEEM if no transmission customer had reserved that capacity for another firm or non-firm transaction. NFEETS would also have the "lowest curtailment priority," meaning that capacity used to provide the service would be the first to be overridden by a competing transmission need.[301] NFEETS would be priced at $0/MWh, based on the lack of opportunity costs associated with otherwise-unused transmission capacity, and any anticipated transmission losses would be reflected in the Energy Exchange prices as financial losses, so that they could be shared between buyer and seller.[302] Lastly, NFEETS would only be obtainable "using the reservation, scheduling and tagging functions" of the SEEM system, such that no transaction would be able to use NFEETS unless it was a

295. PIOs Initial Protest, *supra* note 261, at 22.
296. *Id*. at 22 n.74.
297. D.C. Circuit Remand Order, *supra* note 252, at 1103.
298. *Id*. at 1118.
299. SEEM Proposal, *supra* note 242, at 3.
300. *Id*. at 24.
301. *Id*.
302. *Id*.

transaction guaranteed to generate some amount of cost savings for utility customers.[303]

A few parties filed comments in support of the NFEETS proposal, arguing that the $0/MWh price would help facilitate transactions that might otherwise be economic and would, as a result, deliver benefits to market participants and their customers across the Southeast.[304] One coalition, however, argued that the NFEETS provisions had not been shown to be just and reasonable or compliant with FERC Order No. 888 requirements.[305] The group argued that scheduling NFEETS through SEEM instead of through the usual platform for reserving transmission capacity would be inappropriate,[306] that the SEEM proposal lacked detail on which party to a bilateral transaction would bear any penalties for energy imbalances,[307] and that SEEM participants' use of NFEETS could adversely impact existing, firm transmission customers.[308]

After requesting more information about the provision of NFEETS and its potential impacts on existing transmission customers—and receiving filing parties' response—FERC issued an order in which a majority of commissioners voted to accept the OATT revisions that filing parties submitted to incorporate NFEETS as a new transmission service.[309] Unlike the rest of the SEEM proposal, which FERC declined to issue an order addressing, this standalone Commission order found the OATT revisions that implement NFEETS to be just, reasonable, and not unduly discriminatory or preferential.[310] The Commission explained that NFEETS "will utilize otherwise unused transmission capacity [and] will promote more efficient operation of Participating Transmission Providers' systems, while at the same time reducing the transactional friction normally associated with bilateral transactions."[311] Having determined that the SEEM filing parties had "sufficiently addressed" protesters' concerns about how NFEETS would be reserved and how any penalty charges would be assessed to NFEETS users, the Commission explained that NFEETS' impact on existing, firm transmission customers should be "minimal."[312]

FERC also addressed protesters' arguments that (i) NFEETS represented a discounted transmission rate, (ii) provision of this discounted transmission to one group of parties amounted to the creation of a loose power pool, and (iii) the SEEM proposal, by offering NFEETS pursuant to individual transmission providers

303. SEEM Proposal, *supra* note 242, at 24-25.

304. *See, e.g.*, *Tenn. Valley Pub. Power Ass'n,* Motion to Intervene of Tennessee Valley Public Power Association, Inc., Docket Nos. ER21-1111 et al. at 5 (Mar. 15, 2021); *Associated Elec. Coop., Inc.*, Motion to Intervene and Comments in Support of the Southeast Energy Exchange Market, Docket Nos. ER21-1111 et al. at 3 (Mar. 15, 2021).

305. Clean Energy Coalition Comments, *supra* note 287, at 8.

306. *Id*. at 35.

307. *Id*. at 36-39.

308. *Id*. at 39-40.

309. *See generally* NFEETS Order, *supra* note 248.

310. *Id.* at P 40.

311. *Id*.

312. NFEETS Order, *supra* note 248 at PP 41-43.

OATTs and not pursuant to a joint, market-wide OATT, violated the requirements of Order No. 888 and the Commission's regulations.[313] The Commission rejected these concerns, not only disagreeing with protesters that SEEM constituted a loose power pool, but also waiving the Commission's typical joint OATT requirement and concluding that restricting access to NFEETS to SEEM participants was not unduly discriminatory.[314] In support of these findings, the Commission cited to Order No. 888-A, which defines a loose power pool.[315] The Commission also cited to its precedent in accepting the PSCo JDA, explaining that a zero-dollar rate for NFEETS is just and reasonable because "[j]ust like in *PSCo*, the Southeast EEM Agreement allows for zero-dollar, non-firm service for unused transmission capacity, and thus entails no opportunity costs."[316]

Because FERC accepted the OATT revisions to implement NFEETS via a Commission order supported by a majority of commissioners, the D.C. Circuit reviewed that order separately from its consideration of the rest of the SEEM proposal, which went into effect by operation of law. Applying the Administrative Procedure Act's arbitrary and capricious standard,[317] the court dispensed with many of petitioners' challenges to the NFEETS Order but indicated it found merit in two of the petitioners' arguments.[318]

First, the court expressed that the Commission had failed to explain sufficiently how SEEM's participation requirements would square with the requirements of Order No. 888. The court directed FERC, on remand, to "provide a more fulsome explanation for why the 'market design decisions made by the filing parties'—couched as operational requirements and limits associated with 'technical feasibility'—are actually superior to the status quo in light of Order No. 888's open access principles."[319]

Second, the court took issue with FERC's determination that NFEETS is not a discounted transmission rate, noting that Order No. 888 itself provides that "non-pancaked" transmission, such as NFEETS, is one example of a discounted transmission rate.[320] On the basis of these two findings, the D.C. Circuit held that the Commission had failed to respond adequately to commenters' objections, vacated the NFEETS Order, and remanded the proceeding to FERC for further consideration.[321]

As noted earlier in this section, FERC issued an order, in June 2024, seeking further briefing to assist the Commission in addressing the D.C. Circuit's remand

313. *Id*. at P 62.

314. *Id*.

315. *Id.* at P 63 (citing Order No. 888-A, *supra* note 122, at 31,235).

316. NFEETS Order, *supra* note 248, at P 64. FERC also explained that "Protesters' attempts to distinguish *PSCo* are unavailing" and that "there is no basis in the record to conclude that the Southeast EEM will result in more of a reduction in non-firm transmission revenues than the agreement at issue in *PSCo*."

317. D.C. Circuit Remand Order, *supra* note 252, at 1110 (citing Emera Me. v. FERC, 854 F.3d 9, 21 (D.C. Cir. 2017)).

318. *Id*. at 1111-13.

319. *Id*. at 1113.

320. *Id*. at 1115 (citing Order No. 888, *supra* note 194, at 21,594).

321. D.C. Circuit Remand Order, *supra* note 252, at 1117.

directives.[322] In August 2024, the SEEM filing parties submitted their responses to the Commission's questions.[323] As of the date of this article's publication, several parties had submitted reply briefs or further pleadings, but the Commission had not yet taken further action.[324]

C. *Extended Day-Ahead Energy Markets*

Following these launches of imbalance energy markets and bilateral trading enhancements, market operators in the West and Southwest have begun pioneering more expansive day ahead markets, which extend a range of RTO services to non-RTO market participants.

1. CAISO Extended Day Ahead Market

CAISO in August 2023 filed a proposal to offer participation in the CAISO-operated day-ahead energy market to external BAAs in the Western states through an extended day-ahead market (EDAM). CAISO's EDAM framework would allow western BAAs to offer the output of the generation resources under their operational control into a market with a larger footprint. Because net load imbalances in CAISO's existing footprint have grown in recent years "following rapid growth in variable energy resource capacity, extreme weather-related uncertainty, and extreme weather events,"[325] CAISO concluded that extending participation in its day-ahead market to resources in neighboring BAAs would support the commitment of the lowest-cost power plants needed to serve load, would optimize the use of available regional transmission capacity, and would provide "broad economic, reliability, and environmental benefits" to the region.[326] Thus, CAISO designed its EDAM framework to optimize the transmission and resources offered into the CAISO day-ahead market to identify the most efficient portfolio of resource commitments and energy transfers to meet forecasted demand across the footprint.[327]

CAISO supported its proposal by citing to FERC's 2014 acceptance of CAISO's EIM, which allows other BAAs in the Western Interconnection to participate in the imbalance portion of CAISO's real-time energy market.[328] CAISO also cited to specific sections of its Commission-approved EIM Tariff as support for its argument that extend certain EIM provisions to its day-ahead market would be just and reasonable under the Federal Power Act.[329] CAISO did not explicitly

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322. *Alabama Power Co.*, 187 FERC ¶ 61,174 at P 53 (2024).

323. *See Ala. Power Co.,* Joint Affidavit of Christopher McGeeney and Corey Sellers in response to FERC's 06/14/2024 Briefing Order, FERC Docket Nos. ER21-1111-006 et al.

324. *See, e.g., Adv. Energy United, Inc..,* Reply Brief, pursuant to the Commission's 06/14/2024 Order under ER21-1111 et al., FERC Docket Nos. ER21-1111-006 et al.

325. *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210 at P 7 (2023) [hereinafter Order Accepting EDAM] (citing *Cal. Indep. Sys. Operator Corp.*, Day-Ahead Market Enhancements and Extended Day-Ahead Market, FERC Docket No. ER23-2686-000 at 2-3 (Aug. 23, 2024) [hereinafter CAISO EDAM Proposal]).

326. *Id*. at P 8 (citing CAISO EDAM Proposal, *supra* note 325, at 12-13).

327. *Id*. at P 10 (citing CAISO EDAM Proposal, *supra* note 325, at 13).

328. *Id*. at P 3 (citing EIM Order, *supra* note 75).

329. *See, e.g.*, Order Accepting EDAM, *supra* note 325, at n.32.

tie its proposal to other legal authority, including any citation to Order No. 888 regarding its transmission or CAISO's role as an ISO under Order No. 2000. In defending its proposal, however, CAISO alluded to precedent established by the D.C. Circuit, set out most notably in *Cities of Bethany*, that FERC need not consider alternative proposals if it finds a filing party's proposal to be just and reasonable under the Federal Power Act.[330]

FERC approved most of CAISO's proposal in December 2023.[331] The Commission found that the overall design of EDAM and CAISO's associated day-ahead market enhancements together represented a reasonable and nondiscriminatory framework for accommodating the participation of additional resources in the CAISO energy markets.[332] Overall, the Commission recognized that extending participation in CAISO's day-ahead energy market to resources located in other western BAAs could yield sufficient economic and reliability benefits to participants across the West.[333] FERC also explained that it expected EDAM would help CAISO and other market participants manage the impacts of increasing variable energy generation and extreme weather events in the region by leveraging a larger and more diverse set of resources.[334]

As part of its approval, FERC made several findings on discrete components of CAISO's EDAM proposal that parallel the case studies of other market designs discussed previously.

a. Market Structure & Operational Control

Regarding market structure, FERC noted that CAISO's EDAM filing differed from standard RTO or ISO filings, which typically "propose a consolidated OATT for one market footprint."[335] The EDAM filing, FERC explained, proposed something novel: the development of a day-ahead energy market that would include entities operating both within an ISO-controlled grid—CAISO market participants—and entities operating in external BAAs. Under the EDAM framework, each EDAM participant would offer its energy into a centralized day-ahead energy market while nevertheless operating pursuant to its respective BAA's OATT.[336]

EDAM's market structure also reflects a unique allocation of responsibilities among generating resources, CAISO, and participating BAAs. As proposed, each resource would be responsible for either submitting an economic bid or self-sched-

330. *Id.* at P 10 (citing Cities of Bethany v. FERC, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (Cities of Bethany)).

331. *Id.* at PP 460–65. FERC initially rejected without prejudice CAISO's proposed EDAM access charge, which CAISO had indicated was severable from the rest of its proposal. In a subsequent order issued in June 2024, FERC accepted CAISO's proposed tariff revisions to implement a transmission access charge for EDAM. *See California Independent System Operator Corporation*, 187 FERC ¶ 61,154 (2024).

332. *Id.* at P 41.

333. Order Accepting EDAM, *supra* note 325, at P 42.

334. *Id*.

335. *Id*. at P 43.

336. *Id*.

uling in CAISO's day-ahead market based on its availability and operating parameters.[337] Each resource would also be responsible for satisfying CAISO's communication, telemetry, and control requirements.[338]

CAISO would oversee all four stages of resource participation in the day ahead market: (1) bid submission, (2) market power mitigation, (3) the financial clearing of bid-in supply against bid-in load and ancillary service requirements, and (4) the creation of day-ahead schedules through the residual unit commitment process.[339] In Step 4, EDAM would produce resource commitments and energy transfers that CAISO—as the market operator—would settle and allocate to the appropriate scheduling coordinator for each participating BAA.[340]

Each BAA would be responsible for distributing charges and revenues to the appropriate entities, as the EDAM provisions do not prescribe a methodology for intra-BAA cost allocation.[341] Each BAA must also demonstrate that it has sufficient supply to meet CAISO's resource adequacy, balancing, and flexibility requirements and for complying with CAISO's creditworthiness requirements.[342] In real-time, each BAA would remain responsible for coordinating the scheduling of resources within its operational control and dispatching resources in accordance with their real-time energy schedules.[343]

As FERC explained in approving EDAM's structure, "accommodating multiple market structures requires certain adaptations," such as transmission adaptations and EDAM's resource sufficiency demonstrations.[344] Although these adaptations represent deviations from traditional ISO/RTO market design, FERC noted that the overall EDAM proposal received support from a broad collection of prospective market participants and other stakeholders.[345] FERC's approval of this hybrid market structure—centralized energy offers but decentralized transmission tariffs—represents a concrete step in the evolution of Commission precedent to accommodate greater flexibility both in market design and in the provision of transmission service.

b. Participation

Participation in EDAM would be voluntary and determined on a system-wide basis by each BAA.[346] The primary prerequisite for a balancing authority to join EDAM is its current membership in—or a concurrent application to join—the EIM. Unlike in the EIM, however, all resources located within a BAA that elects to join EDAM must participate in both the day-ahead and real-time energy markets

337. Order Accepting EDAM, *supra* note 325, at P 14.
338. *Id*. at P 26.
339. *Id*. at PP 4-6.
340. *Id*. at P 18.
341. Order Accepting EDAM, *supra* note 325, at P 205.
342. *Id*. at P 13.
343. CAISO EDAM Proposal, *supra* note 76, at 104.
344. Order Accepting EDAM, *supra* note 325, at P 43.
345. *Id*. at n.55.
346. *Id*. at P 20.

either by submitting economic bids or by self-scheduling their participation as price takers.[347] Although every resource in a participating BAA is required to bid into EDAM, each BAA will have the flexibility to determine how much of each resource's capacity it offers into the day-ahead market.[348]

The Tariff provisions that govern EDAM participation set out four categories of participants: (1) EDAM Entities, i.e., the participating BAAs; (2) EDAM Resources; (3) EDAM Transmission Service Providers; and (4) EDAM LSEs. The Tariff defines the roles and responsibilities of each category and provides *pro forma* participation agreements for each.[349] To participate in EDAM, each party must execute the relevant participation agreement with CAISO and engage in a period of parallel operation with CAISO.[350]

Although CAISO explained that the EDAM framework and these standard forms were designed with the goal of accommodating a diverse group of western BAAs, each BAA and participating transmission provider would need to develop individualized OATT changes to facilitate its participation in EDAM.[351] Each BAA would further need to develop a methodology to allocate EDAM revenues and costs within its territory, ideally through a stakeholder process.[352] And each transmission provider would need to harmonize its existing menu of transmission services with those used to facilitate EDAM participation.[353]

No stakeholder expressed a view that the EDAM participation requirements would represent unreasonable or anticompetitive barriers to entry. This lack of protests on CAISO's proposed participation requirements stands in stark contrast to the reception that SEEM's participation requirements received, as discussed above. A few EDAM commenters instead noted limited and often situation-specific concerns. One utility, for example, expressed concern that transmission providers might be forced to participate in EDAM if they own assets or transmission rights within a certain BAA.[354] The same utility also argued that resources operating within the territory of a participating BAA should be able to opt out of participation.[355] In response, CAISO explained that third-party asset- or rights-owners would have the ability to carve themselves out of the BAA's participation.[356]

347. *Id*.
348. Order Accepting EDAM, *supra* note 325, at P 220.
349. *Id.* at P 21.
350. *Id.* at PP 207–08.
351. *Id.* at P 205.
352. Order Accepting EDAM, *supra* note 325, at P 206.
353. *Id.* at P 205.
354. *Id.* at P 213.
355. *Id.* at P 220.
356. Order Accepting EDAM, *supra* note 325, at P 217.

c. Governance

CAISO proposed a governance framework for EDAM that would extend the jurisdiction of the existing "WEIM Governing Body"—the committee of five independent members that oversees the EIM—to oversee EDAM as well.[357] The EDAM governance framework, like the existing EIM governance structure, would divide authority between the WEIM Governing Body and the CAISO Board of Governors.[358] CAISO committed to briefing its Board of Governors and the WEIM Governing Body on "all aspects" of EDAM, including the market's implementation, any market simulations, the role of market parameters, and—once operable—market performance.[359] Any revisions to CAISO's business practice manuals that address EDAM participation, including changes to EDAM market parameters, would only be made as part of the stakeholder process, which itself allows for appeals.[360]

Several stakeholders expressed concern that CAISO's proposed governance framework for EDAM would not be sufficiently independent from the CAISO Board of Governors and, by extension, from California interests.[361] A federal utility argued that CAISO should develop a more independent and representative governance structure for EDAM, especially because it views EDAM as a potential stepping-stone to a broader Western RTO.[362] Another stakeholder questioned the dual roles that both CAISO and its Board of Governors would be expected to play regarding EDAM: in the case of CAISO, the roles of market operator and balancing authority; and in the case of the Board of Governors, the oversight of both these operator and balancing authority functions.[363]

Despite these concerns, FERC approved CAISO's EDAM governance proposal, noting that the structure was consistent with the existing EIM governance structure, which the Commission approved as just and reasonable in 2014.[364] The Commission did not provide further detail when it explained that it was not persuaded by protesters' concerns about the WEIM/ EDAM Governing Body's independence, aside from noting that EDAM is a voluntary market and that participants may file complaints at FERC.[365]

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357. *Id.* at P 476; *see* CAL. INDEP. SYS. OPERATOR, CHARTER FOR ENERGY IMBALANCE MARKET GOVERNANCE, https://www.westerneim.com/Documents/CharterforEnergyImbalanceMarketGovernance.pdf (last visited Jan. 14, 2024).

358. *Id.*; *see Governance and committees*, CAL. INDEP. SYS. OPERATOR, https://www.caiso.com/informed/Pages/BoardCommittees/Default.aspx (last visited Jan. 14, 2024).

359. *Id.* at P 142.

360. Order Accepting EDAM, *supra* note 325, at P 142.

361. *Id.* at PP 477–79.

362. *Id.* at P 478.

363. *Id.* at PP 480–81.

364. Order Accepting EDAM, *supra* note 325, at P 484 (citing EIM Order, *supra* note 75, at P 109).

365. *Id.*

d. Pricing

CAISO proposed to calculate a marginal energy cost for each participating BAA by adding the BAA-specific redispatch costs arising from transmission congestion to the system-wide marginal energy price.[366] In plain language, this means that CAISO would calculate a baseline day-ahead energy price for each EDAM Entity based on the total cost of delivering one megawatt-hour of energy to a customer in that EDAM Entity's territory. CAISO noted that each EDAM Entity would be able to use its BAA-wide marginal energy cost as a starting point to calculate LMPs within its footprint.[367]

CAISO currently uses a similar process to calculate the real-time marginal energy cost for the EIM.[368] In the EIM, however, potential energy transfers are reflected as part of a BAA's marginal energy cost, whereas energy transfers in EDAM may be scheduled and settled separately from other energy settlements.[369] CAISO concluded that pricing in EDAM would need to be calculated for each BAA instead of for the entire system because of this difference.[370] The designated market monitor would evaluate imbalance reserves and day-ahead energy prices separately and would mitigate each to competitive levels as necessary.[371]

CAISO's proposed pricing methodology received wide-ranging feedback. One stakeholder argued that calculating a BAA-specific marginal energy cost instead of a system-wide cost would obscure a price signal that market participants rely on.[372] Another, conversely, called for even more granular pricing and argued that CAISO's EDAM proposal departed from Commission policy on price formation.[373]

FERC accepted CAISO's proposed pricing framework, determining that "it is no longer necessary or appropriate to reference a system marginal energy cost" in the formation of LMPs and that CAISO's proposal to calculate BAA-specific marginal energy costs is reasonable.[374] Because BAAs in EDAM can receive revenues for energy transfers, calculating a single system marginal cost would not

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366. *Id.* at P 394.

367. *Id.*

368. Order Accepting EDAM, *supra* note 325, at P 396. *See also id*. PP 4-6. Because CAISO's EDAM proposal represents an extension of CAISO's existing day-ahead markets to participants in other BAAs, the system-wide market price for energy in EDAM will be those that result from CAISO's Integrated Forward Market (IFM). CAISO's IFM is a financial market that clears bid-in supply against bid-in load and ancillary service requirements. After the IFM yields its set of market clearing prices for each location—LMPs—CAISO procures any additional capacity needed to fill the gaps between the financial market solution and the physical supply needed to meet forecasted demand.

369. *Id.* at P 395.

370. *Id.*

371. Order Accepting EDAM, *supra* note 325, at PP 152, 173.

372. *Id.* at P 397.

373. *Id.* at P 398 ("Powerex asserts that price formation is a critical topic in the context of EDAM and notes that EDAM will not incorporate fast-start or "robust" scarcity pricing, diverging from other organized markets and Commission policy on price formation").

374. *Id.* at P 401.

reflect the true costs for energy in each BAA.[375] FERC instead concluded that CAISO's calculation of a separate marginal energy cost for each BAA would provide sufficiently transparent price signals to market participants.[376]

e. Transmission Service

At a high level, CAISO's EDAM transmission framework requires each transmission provider operating in each participating BAA to amend its OATT to make its transmission system available to EDAM.[377] Unlike the EIM, which uses as-available transmission to support real-time energy transfers, transmission capability made available to EDAM to support day-ahead schedules must also be reserved for real-time use so that market transfers arranged through EDAM can be effectuated in real time.[378] In other words, parties must carry forward day-ahead transmission reservations into real time. Consequently, resources participating in EDAM either must reserve transmission in advance under their transmission provider's OATT or must pay a transmission charge for the real-time use of previously-unreserved transmission capacity.[379]

More specifically, the EDAM transmission framework can be broken into three steps.[380] First, EDAM BAAs would provide transmission system information for the transmission capacity they make available to EDAM.[381] Second, CAISO would assign legacy transmission contracts priority over EDAM scheduling.[382] Third, CAISO would enable each EDAM Entity's transmission customers to reflect their existing transmission rights in the market.[383] Steps two and three are designed to respect existing transmission obligations and to ensure that EDAM BAAs can continue to serve their local load reliably.[384] As a further failsafe, each EDAM BAA would retain ultimate control over its own transmission system and CAISO would defer to the local BAA in managing infeasibilities.[385]

CAISO's EDAM transmission framework was designed to maximize the amount of transmission capacity that is available to the market.[386] The framework was also designed to strike an appropriate balance between respecting existing contract rights for transmission and making sufficient transmission available to EDAM to allow the market to produce regional benefits.[387]

375. Order Accepting EDAM, *supra* note 325, at P 401.

376. *Id.*

377. *Id.*

378. *Id.* at P 242.

379. Order Accepting EDAM, *supra* note 325, at P 246.

380. *Id.* at PP 243-45.

381. *Id.* at P 243.

382. *Id.* at P 244.

383. Order Accepting EDAM, *supra* note 325, at P 245.

384. *Id.*

385. *Id.* at P 247.

386. *Id.* at P 241.

387. Order Accepting EDAM, *supra* note 325, at P 282.

Many commenters expressed support for the EDAM transmission framework.[388] Some argued that CAISO's treatment of OATT rights would be at least as robust as what FERC's *pro forma* OATT requires.[389] A few expressed strong support for CAISO's framework, arguing that it not only preserves the firm nature of OATT service in line with the requirements of the Commission's *pro forma* OATT, but also that it appropriately addresses the needs of the existing Western Resource Adequacy Program.[390] Others referred to the proposed transmission framework as a reasonable starting point from which a more sophisticated transmission model should be developed in the future.[391] Not all feedback was positive, however. Several commenters highlighted what they perceive as shortcomings in the framework, seeking assurances that the EDAM design would not erode existing transmission rights,[392] produce infeasible solutions,[393] or enable market manipulation through transmission withholding.[394]

In approving the proposal, FERC agreed that CAISO's EDAM transmission framework would preserve legacy transmission rights by allowing EDAM Entities to use their existing transmission rights to participate in EDAM while making any remaining transmission capacity available to EDAM on an as-available basis.[395] FERC also found the overall framework to be consistent with or superior to the *pro forma* OATT.[396] The Commission noted, however, that its acceptance of the proposed transmission framework for EDAM did not pre-determine action on any prospective EDAM Entity or EDAM transmission service provider's individual filing.[397] The Commission committed to reviewing all future filings on a case-by-case basis to determine whether each entity's proposed OATT revisions to facilitate its participation in EDAM continued to comply with the *pro forma* OATT.[398]

2. SPP Markets+

As noted earlier in this article, SPP, in March 2024, submitted a proposal to implement a centralized day-ahead and real-time unit commitment and dispatch market (Markets+) in the Western interconnection.[399] Markets+ would enable SPP to offer a suite of RTO-like services to non-member BAAs, including facilitating the participation of external BAAs in SPP's day-ahead market. Under the proposed Markets+ tariff, transmission providers and BAA operators would continue to fulfill their existing roles and obligations, except that SPP would administer and

388. *Id.* at PP 250–81.
389. *Id.* at PP 256–57, 261.
390. *Id.* at PP 261, 270.
391. Order Accepting EDAM, *supra* note 325, at PP 250, 254, 258.
392. *Id.* at P 255.
393. *Id.* at P 263.
394. *Id.* at P 252.
395. Order Accepting EDAM, *supra* note 325, at P 307.
396. *Id.*
397. *Id.* at P 308.
398. *Id.*
399. *See Southwest Power Pool,* Submission of Tariff to Establish Markets+, FERC Docket No. ER24-1658-000 (Mar. 29, 2024) [hereinafter Submission of Tariff to Establish Markets+]

operate a centrally committed and dispatched day-ahead market and real-time balancing market for the resources and loads within the Markets+ footprint.[400]

At the time of this article's publication, FERC had not yet issued a final order on SPP's Markets+ proposal,[401] and thus Markets+ does not yet form part of the legal landscape for non-RTO organized markets. Nevertheless, SPP's proposal mirrors that of CAISO's EDAM framework in several key ways. For example, Markets+—like EDAM—proposes to use existing generation and transmission more efficiently by committing and dispatching resources across several BAAs and transmission owners' systems.[402] Markets+ also would limit commitment and dispatch to available transmission, similarly to EDAM, and would provide market access to all resources and loads in participating BAAs.[403] If SPP's proposal were approved, it would establish a potential rival to CAISO's EDAM by offering BAAs in the Western interconnection a choice of day-ahead market constructs. SPP's proposal therefore provides useful additional context for what SPP and other market operators may see as the future of non-RTO organized markets.

Despite these similarities between SPP's Markets+ proposal and CAISO's Commission-approved EDAM framework, however, FERC staff posed questions to SPP that highlight certain topics grid operators may need to better flesh out in developing future organized market proposals. Transmission, for example, remains a major challenge—including both the designation of transmission that will be made available to a non-RTO market and how the priority of non-RTO transmission reservations will stack up against existing transmission uses.[404] Greenhouse gas accounting, a necessary component of many western states' decarbonization plans, also creates challenges for would-be market designs, as evidenced by FERC staff's questions on SPP's proposed methodology for incorporating greenhouse gas accounting mechanisms into its proposed market design.[405]

V. SUMMARY OF COMMON CHARACTERISTICS AMONG NON-RTO MARKETS

Evaluating the preceding market designs can help define what passes legal muster with FERC—and potentially reviewing courts—when filing parties propose a new market structure. The next two pages includes a summary table comparing the characteristics of the five non-RTO markets discussed above, i.e., excluding Markets+. Following the summary table, summary sections explain how FERC's determinations on each market design component contributes to the creation of an overarching framework for just, reasonable, and not unduly discriminatory non-RTO organized markets.

400. *Id*. at 5.

401. *See* Markets+ Deficiency Letter, *supra* note 22, at 1 (explaining that FERC staff in late July 2024 issued a deficiency letter seeking additional information about SPP's Markets+ proposal).

402. *See* Submission of Tariff to Establish Markets+, *supra* note 399, at 4.

403. *Id*. at 5.

404. *See, e.g.*, Markets+ Deficiency Letter, *supra* note 22, at 1-4.

405. *See id.* at 6–8.

Market	Structure & Operational Control	Participation	Governance	Pricing	Transmission Use
EIM	• 5-minute energy transfers • Extension of existing CAISO imbalance energy market • Financial settlement only • BAAs maintain operational control within their own footprints	• Voluntary participation by each BAA and resources within participating BAAs • Participants must execute a participation agreement and complete certain pre-integration tests	• Three- part governance structure: (1) EIM Governing Body, (2) oversight by the Body of State Regulators, (3) convening of a quarterly Regional Issues Forum that is open to the public • CAISO Department of Market Monitoring provides monitoring and market power mitigation services	• LMP • Costs for energy transfers allocated by CAISO to transacting BAAs • EIM transfer prices may be mitigated if a transacting party has market power	• As-available transmission, lowest priority • No wheeling charge for use of reciprocal transmission systems • Standard transmission charge for transfer recipients
PSCo JDA	• Real-time joint dispatch of all shared, "dispatchable" generation resources using SCED • Participating utilities maintain authority over resource planning, commitment, and operations • PSCo settles the market and bills participants, who pay each other directly	• Participation limited to load-serving entities within the PSCo BAA • Participants must execute a joint dispatch agreement and either secure--or provide themselves-- JDTS	• No formal governance structure	• Joint Dispatch Energy: LMP plus $0.50/MWh admin. fee • Surplus Energy: LMP minus $1/MWh plus admin. fee • Deficit Energy: LMP plus $10/MWh adder plus admin. fee	• As-available transmission, lowest priority • $0/MWh • Participants (LSEs) must provide reciprocal transmission system use
WEIS	• 5-minute energy imbalance market open to participating resources across the market footprint • All resources in a participating BAA must register with SPP and either execute a WJDA or opt out • Participants retain operational control • SPP dispatches the market using SCED and settles all imbalance energy	• Participation limited to BAAs in the Western Interconnect that do not already belong to SPP • Participants must execute a joint dispatch agreement and secure--or provide-- JDTS	• Western Market Executive Committee (WMEC) is the governing body for WEIS • Each WEIS market participant contributes a representative to WMEC • Proposals must be approved by supermajorities of both popular and load-weighted votes • Any party may request a market rule revision	• LMP, adjusted for marginal losses	• As-available transmission, lowest priority • SPP will model only available transmission • $0/MWh • Participants must provide reciprocal transmission system use
SEEM	• SEEM matches participant bids and offers into bilateral energy exchanges • Energy exchanges are arranged in 15-minute increments • No centralized market clearing or dispatch • Participants retain operational control • Parties settle transactions bilaterally	• Own or control a source or sink in the SEEM footprint • execute a participation agreement • arrange to take NFEETS from all necessary transmission providers • enter into enabling agreements with 3+ potential counterparties	• Members contribute voting representatives to a Membership Board • Sector representatives sit on an Operating Committee, which oversees SEEM operations • Third party auditor reviews market integrity	• "Split-the-savings" price at the midpoint between each bid–offer pair • Financial losses shared equally between buyer and seller • Transaction prices cost-capped for participants with mitigated MBR authority	• As-available transmission, lowest priority • $0/MWh, with any losses split as financial losses between buyer and seller • Offered under individual OATTs of SEEM Participating Transmission Providers
EDAM	• CAISO conducts a centralized, day-ahead energy auction • All resources in a participating BAA must either bid or self-schedule • Resource bids are reviewed for market power and cleared using SCED to create day-ahead schedules • CAISO settles the market and bills participants	• Participation determined BAA by BAA • execute a participation agreement • engage in pre-integration testing • voluntary participation: every resource in a participating BAA must submit economic bids or self-schedule	• Like EIM, three- part governance structure: (1) EIM Governing Body, (2) oversight by the Body of State Regulators, (3) convening of quarterly Regional Issues Forum • CAISO Department of Market Monitoring provides monitoring and market power mitigation services	• BAA-specific day-ahead LMP • day-ahead priced mitigated by CAISO DMM, as needed	• Participants (BAAs) must make unused transmission available to EDAM • Individual participants must either reserve unused transmission to receive $0/MWh transmission or must pay a standard transmission charge for the use of unreserved transmission

A. Overall Market Structure

Of the five approved non-RTO markets, only the PSCo JDA proposed centralized dispatch of participating resources, perhaps because PSCo offered participation only to utilities for which it already served as the balancing authority. The other four market proposals explained that existing balancing authorities would maintain operational control within their own footprints. The EIM, WEIS Market, and EDAM, for example, all noted that although the RTO would conduct centralized energy auctions, settle the market, and issue bills to participants, resources participating in those markets would continue to conduct their own resource planning and commitment processes.

SEEM's structure differed from the other four markets because although SEEM also left operational control of participating resources to resource owners, the market design did not include any centralized clearing mechanism or dispatch signal. Instead, SEEM proposed only that its algorithm would identify potential counterparties for energy bids and offers associated with fifteen-minute delivery periods; the matched pair counterparties would be responsible for executing energy exchanges and settling those transactions bilaterally.

FERC's acceptance of both types of market structures suggests that both centralized clearing and decentralized matching of market participants may be considered reasonable under the Federal Power Act. Furthermore, FERC reiterated both in approving the PSCo JDA and in approving SEEM that voluntarily organized markets need not be held to the same standards as either fully-fledged RTOs or power pools.[406]

FERC only invoked Order No. 2000 in one of the five orders—its order accepting CAISO's EIM proposal.[407] The Commission explained in that order that it had required the elimination of intra-RTO transmission rate pancaking, as a matter of policy, but clarified that Order No. 2000 did not prohibit rate pancaking between RTOs or in other regions of the country.

In sum, the orders accepting all five non-RTO organized market structures suggest that non-RTO markets may be centrally cleared or settled bilaterally, that operational control may be ceded to market operators or retained by resource owners, and that market participants may continue to conduct their own planning, scheduling, and resource commitment processes, all while remaining compliant with the Federal Power Act and FERC precedent.

B. *Participation*

Participation requirements varied only slightly among the five markets. The EIM proposed arguably the most flexible set of participation requirements, with provisions that allowed EIM participation both by BAAs and by individual resources who would meet the criteria for participating in CAISO's energy market.[408] Furthermore, the EIM rules required only that prospective participants execute a participation agreement and complete certain pre-integration tests to participate. The EIM did not require that participants furnish or secure their own transmission, but—as a result—the EIM also did not exempt participants from transmission charges in their home BAA; it only exempted participants from wheeling charges for the use of transmission systems within the broader EIM footprint.[409]

Both the PSCo JDA and WEIS implemented more restrictive participation requirements, establishing that only LSEs located within the PSCo BAA or only BAAs in the western interconnect, respectively, would be able to elect to participate.[410] EDAM also required that participation would be determined at the BAA level and that every resource within a participating BAA must be accounted for in the market, either by bidding or by self-scheduling.[411]

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406. *See* NFEETS Order, *supra* note 248, at P 22; Order Accepting PSCo JDA, *supra* note 191, at P 85.

407. EIM Order, *supra* note 75, at P 155.

408. *Id.* at P 21.

409. *Id.* at P 53.

410. Order Accepting PSCo JDA, *supra* note 191, at P 22; WEIS Market Order, *supra* note 140, at P 9.

411. Order Accepting EDAM, *supra* note 325, at P 320.

The participation requirements for SEEM strike a balance between facilitating broad participation and ensuring that all resources are deliverable to the market. SEEM's requirement that prospective participants must own only a source or sink within the SEEM footprint is less restrictive than the PSCo JDA, which limited participation to LSEs, or WEIS and EDAM, which limited participation to BAAs. An individual resource owner, therefore, could elect to participate in SEEM where it could not in other markets. Similarly, because all participating transmission owners have agreed to provide zero-cost NFEETS to energy exchanges throughout the SEEM footprint, individual resources do not need either to secure reciprocal transmission system use, like they would in PSCo or WEIS, or to pay for transmission, like they would in the EIM.[412] Yet SEEM's requirement that participants execute bilateral contracts with at least three potential counterparties represents a potential barrier to entry that the other markets lack because—at least in theory—all existing participants could collude to prevent a new participant from joining.[413]

Of all the markets, SEEM received the most criticism of its proposed participation requirements, despite the relatively moderate nature of those requirements. FERC alluded somewhat to this discrepancy when it explained in the NFEETS Order that "it is not uncommon to require execution of an agreement like the Participant Agreement for voluntary structures like the Southeast EEM" and the provision of a standard form protects against undue discrimination.[414]

Stakeholders' concerns about participation requirements, therefore, may not be grounded solely in the letter of those requirements, but also in the perceived fairness of market governance and oversight. Both WEIS and EDAM, the two other markets approved since 2020, are operated by RTOs and are monitored by those RTOs' market monitors. This distinction may have preempted some stakeholder concerns about the potential anti-competitive impacts of participation requirements as applied to individual participants.

As of November 2024, the legal landscape for non-RTO market participation requirements remains broad and generally permissive. Furthermore, although the D.C. Circuit may scrutinize the SEEM framework more closely in the future, the court preliminarily validated FERC's determination that SEEM's participation requirements were just and reasonable, noting that "the Commission properly concluded that the record demonstrated that SEEM's structure disincentivizes" anti-competitive behavior, such as refusing to trade with potential counterparties.[415]

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412. *See*, e.g., Order Accepting PSCo JDA, *supra* note 191, at P 22.

413. SEEM Proposal, *supra* note 242, at 16.

414. NFEETS Order, *supra* note 248, at P 69 (citing Order Accepting PSCo JDA, *supra* note 191, at P 85 (noting that prospective participants "only need[] to sign the Joint Dispatch Agreement" to participate in the JDA); EIM Order, *supra* note 75, at P 6 (noting that CAISO proposed a *pro forma* agreement for use by participants in the EIM)).

415. D.C. Circuit Remand Order, *supra* note 252, at 1111.

C. *Governance*

The five markets vary widely in their governance structures. The PSCo JDA, for example, did not establish any formal governance framework. Furthermore, that lack of formal governance procedures was not protested before FERC, which seems surprising in light of the extensive criticism that SEEM's governance framework received and, to a lesser extent, protests of WEIS Market governance.

In lieu of a standalone board of directors or operating committee, PSCo had explained that the JDA would rely on audit rights and transparency measures to enable participants to verify "the accuracy of any statement, charge, or computation" on an *ad hoc* basis.[416] When FERC questioned this initial lack of procedure, PSCo proposed that an Audit Committee composed of JDA participant representatives would also conduct routine oversight of JDA operations.[417] Although FERC accepted the PSCo JDA proposal, it declined to address the Audit Committee or specific transparency measures in its order.

The two other markets established prior to 2020—the EIM and SPP's WEIS Market—proposed governance structures that resembled pared-back versions of their existing RTO governance processes. CAISO proposed, for example, that the EIM would be overseen by three entities: its own Governing Body, a pre-existing Body of State Regulators, and a pre-existing Regional Issues Forum.[418] The EIM proposal did not specify vote thresholds, but SPP proposed that modifications to its WEIS Market would need to be approved by a supermajority of participants, measured both by popular and load-weighted votes.[419]

SEEM's governance framework borrowed from the frameworks of its three predecessors: members would contribute voting representatives to a Membership Board and Operating Committee; SEEM would hire a third-party auditor to oversee its matching system; and the market would host public annual meetings, akin to CAISO's Regional Issues Forum.

But whereas criticism of the PSCo JDA proposal was limited to the scope of audit rights and critics of the EIM governance framework argued only that CAISO would have too much oversight authority,[420] several stakeholders took issue with the governance frameworks proposed for the WEIS Market and for SEEM. At least one protester argued that each market unreasonably limited voting rights to market participants.[421] Others accused each market's governance system of affording a disproportionate amount of decision-making power to a few large utilities.[422]

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416. Order Accepting PSCo JDA, *supra* note 191, at P 19.

417. *Id*. at P 69.

418. EIM Charter, *supra* note 98, at 2.

419. WEIS Market Order, *supra* note 140, at P 53. Notably, EDAM's governance proposal copied the EIM governance framework almost exactly. Perhaps as a result, only one party protested the framework, arguing that it afforded California interests too much control. *See* Order Accepting EDAM, *supra* note 325, at P 477.

420. EIM Order, *supra* note 75, at PP 105-06 n.34

421. *See* WEIS Market Order, *supra* note 140, at P 57; PIOs Initial Protest, *supra* note 261, at 28.

422. *See* WEIS Market Order, *supra* note 140, at P 56; Clean Energy Coalition Comments, *supra* note 287, at 19.

Due to these variations and the odd procedural posture of SEEM's having gone into effect by operation of law, little Commission guidance exists on what components a non-RTO organized market must include in its governance framework to pass legal muster. In accepting the WEIS Market, FERC explained that limiting voting rights to market participants was reasonable, both because participants "have made a financial commitment to the WEIS Market" and because any party could receive voting rights by executing a participation agreement.[423] FERC also determined that SPP's WMEC Charter afforded adequate opportunity for non-participants to participate in the WEIS Market stakeholder process.[424] In addressing the SEEM proposal, furthermore, both FERC and the D.C. Circuit declined to make specific determinations about the legality of SEEM's governance framework.[425]

Perhaps because of the lack of consistent guidance, commenters have argued more strenuously in protests of the more recent market designs that governance frameworks need to provide greater access to non-participant stakeholders.[426] As non-RTO regions continue not only to develop more sophisticated markets but also to expand the services they offer from sub-hourly energy or imbalance energy service to day-ahead energy markets and coordinated regional planning, FERC may need to speak more clearly on what level of governance it will require for non-RTO markets. As long as these market structures remain voluntary, FERC may decline to impose the governance requirements on non-RTO markets that Order No. 2000 maintains for RTOs. But the Commission may wish to develop a more formalized roadmap—or even issue a policy statement—that outlines what it considers "just and reasonable" when it comes to market governance.

D. Pricing

Four of the five markets use some form of LMP determined through a centralized market clearing process. The EIM prices imbalance energy at LMP, mitigated as needed to comply with transacting parties' MBR authorizations.[427] The PSCo JDA also prices its three products—Joint Dispatch Energy, Surplus Energy, and Deficit Energy—at LMP plus an administrative fee, with the latter two services' prices further adjusted to provide a financial incentive for resources to follow PSCo's dispatch signals.[428] The WEIS Market proposed perhaps the purest pricing, setting the price for imbalance energy at LMP, adjusted for marginal losses.[429] And although EDAM differs from the other markets in that it establishes

423. WEIS Market Order, *supra* note 140, at P 66.

424. *Id.* at P 67.

425. *See* D.C. Circuit Remand Order, *supra* note 252, at 1103.

426. *See, e.g.*, Clean Energy Coalition Comments, *supra* note 287, 19; PIOs Initial Protest, *supra* note 261, at 28 (in response to SEEM); Order Accepting EDAM, *supra* note 325, at P 478.

427. EIM Order, *supra* note 75, at P 40.

428. Order Accepting PSCo JDA, *supra* note 191, at PP 14-15.

429. WEIS Market Order, *supra* note 140, at PP 8, 85.

day-ahead—and not real-time—energy prices, CAISO also proposed to use LMP to develop schedules for resources within the EDAM footprint.[430]

SEEM is the only market that does not use LMP, but SEEM's "split-the-savings" pricing was designed to reflect the bilateral nature of Energy Exchange transactions and to comply with the market's requirement that transacting parties settle with each other directly.[431] Because SEEM transactions represent matched, bilateral transactions between an offeror and a bidder, the midpoint pricing formula guarantees that each party receives half of the cost savings generated by the transaction. Although FERC did not opine on SEEM's "split-the-savings" pricing because SEEM went into effect by operation of law, the D.C. Circuit noted that "traditional wholesale markets still exist" and that vertically integrated utilities have long traded energy bilaterally, albeit without the assistance of a matching algorithm.[432]

Overall, FERC's acceptance of both LMP and midpoint pricing for short-term energy sales indicates that either is a viable alternative for non-RTO organized markets.

E. Transmission

Most of the non-RTO markets proposed transmission schemes that share several common characteristics. All five indicate that their transactions will be delivered—or scheduled and delivered, in the case of EDAM—across "as-available transmission," i.e., transmission that has not been reserved for any other firm or non-firm transmission service and would otherwise go unused. Transactions in all five markets also would be assigned the lowest priority, meaning that they would be curtailed before other, scheduled transmission service.

Four of the five markets—all but the EIM—establish that their baseline transmission charge for using this surplus transmission capacity will be $0/MWh. Several market designs attached additional conditions to the use of this zero-dollar transmission, however. The PSCo JDA and WEIS Market require that participants must provide reciprocal use of their own transmission facilities to take advantage of zero-dollar transmission service across others' transmission facilities.[433] EDAM allows participants to reserve unused transmission capacity to receive the zero-dollar rate, but also allows for participants to be charged standard transmission rates if they use transmission without a reservation.[434]

The EIM and EDAM require that participating BAAs make their unused transmission available to the markets, although the EIM assesses standard transmission charges to imbalance energy transactions whereas EDAM enables participants to use zero-dollar transmission service. The PSCo JDA, similarly, required

430. Order Accepting EDAM, *supra* note 325, at P 394.

431. *See* SEEM Proposal, *supra* note 242, at 4-5.

432. D.C. Circuit Remand Order, *supra* note 252, at 1103

433. Order Accepting PSCo JDA, *supra* note 191, at P 35; WEIS Market Order, *supra* note 140, at P 8.

434. Order Accepting EDAM, *supra* note 325, at P 246.

that participating LSEs make an "in-kind" commitment of reciprocal transmission capacity.[435]

SEEM also required market participants who own transmission to modify their OATTs to establish NFEETS as a service and agree to provide NFEETS to SEEM participants.[436] FERC affirmatively blessed SEEM's transmission framework in its NFEETS Order, finding not only that the zero-dollar rate for NFEETS was just and reasonable based on the service's lack of opportunity costs, but also that it was reasonable for SEEM participating transmission providers to offer NFEETS pursuant to their individual OATTs.[437] The Commission used the NFEETS Order to explain more of its rationale for why the requirements of Order No. 888 did not necessitate that SEEM's filing parties develop a Joint OATT. FERC explained that requiring a Joint OATT "would place form over substance" because NFEETS would be provided by FERC-jurisdictional transmission providers in accordance with OATTs that remain on file with the Commission and subject to the Federal Power Act.[438] FERC further agreed with the SEEM filing parties that requiring a joint, system-wide OATT could jeopardize the expected benefits of the Southeast EEM by precluding the membership of the Tennessee Valley Authority without providing any clear "increase in functionality or benefits" to SEEM participants.[439]

The D.C. Circuit signaled its potential agreement with FERC's findings on NFEETS. Nevertheless, Judge Wilkins, writing for the majority, expressed skepticism about the Commission's explanation for why NFEETS should not be considered discounted transmission and why, therefore, SEEM should not be required to file a Joint OATT with the Commission to comply with Order No. 888.[440] The court directed the Commission, on remand, to "provide a more fulsome explanation for why the market design decisions made by the filing parties" are "superior to the status quo in light of Order No. 888's open access principles."[441]

The Commission's June 2024 order directing further briefing, however, likely postpones any further D.C. Circuit decision regarding what counts as discounted transmission service and whether identical OATTs may be substituted for a Joint OATT until after the Commission has reviewed the briefs it requested and issued a further order on the merits of the SEEM market construct. Although any future decision by the D.C. Circuit would affect SEEM alone, zero-dollar transmission underpins all five extant market structures, so a finding by the court that zero-dollar transmission will be considered discounted transmission service for the purpose of evaluating compliance with Order No. 888 would represent a substantial shift in the legal landscape for non-RTO market design.

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435. Order Accepting PSCo JDA, *supra* note 191, at P 35.
436. NFEETS Order, *supra* note 248, at P 40.
437. *Id.* at P 62 (citing Order No. 888-A, *supra* note 122, at 31,235).
438. *Id.* at P 73.
439. *Id.*
440. D.C. Circuit Remand Order, *supra* note 252, at 1115, 1117.
441. *Id.* at 1113.

VI. PAST AND PLANNED NON-RTO MARKET CONSOLIDATION

Only four of the five market structures remain operational as of this article's publication. PSCo—doing business as Xcel Energy-Colorado—and the other JDA parties announced in January 2022 that they would join the WEIS Market, which SPP operates.[442] In late March 2023, FERC accepted revisions to PSCo's tariff to reflect its authorization to participate in the WEIS Market, effective April 1, 2023.[443]

SPP also recently announced its plan to phase out the WEIS Market after the RTO launches two new markets: (i) Markets+; (ii) and an expanded, fully integrated western RTO.[444] As of 2024, however, the WEIS Market remains operational and represents the state of market development available to non-SPP BAAs in the western interconnect.

Regardless of these past and planned reorganizations, FERC's approvals of all five market structures together form the existing legal landscape for non-RTO organized markets. Stakeholders working to develop new markets, therefore, should be able to model future market proposals after the components that FERC and reviewing courts have found to be just, reasonable, and compliant with existing laws and regulations.

VII. CONCLUSION

The Commission's relatively recent approvals of these five market structures could not exist without the foundation laid by FERC's earlier landmark orders, however. As introduced before the market summaries, Order No. 888 required all FERC-jurisdictional transmission providers to maintain OATTs that set out non-discriminatory terms for their provision of transmission service. FERC in Order No. 2000 then established a comprehensive list of requirements for RTOs that were designed to ensure just and reasonable rates for electricity, facilitate regional coordination, and promote transparency in regional markets. Because the Commission stopped short of mandating RTO membership, however, FERC-jurisdictional utilities located in non-RTO regions of the country were required to comply with Order No. 888—including Order No. 888's requirements for power pools—but were not required to pursue the type of coordinated market development envisioned by Order No. 2000.[445] As a result, when these regions—including the West, Southeast and Southwest—began to form the non-RTO organized markets described in the prior section, FERC operated largely without a roadmap in reviewing whether proposed market designs would satisfy the requirements of the Federal Power Act.

A review of all five markets suggests that states still have wide latitude in designing markets that reflect their regional preferences, so long as the resulting

442. *Colorado Utilities Plan to Join the Western Energy Imbalance Service Market*, SW. POWER POOL (Jan. 25, 2022), https://www.spp.org/news-list/colorado-utilities-plan-to-join-the-western-energy-imbalance-service-market/.

443. *Public Service Company of Colorado*, 182 FERC ¶ 61,223 (2023).

444. *SPP to Phase Out WEIS as New Market Offerings Expand*, RTO INSIDER (Apr. 14, 2022), https://www.rtoinsider.com/29946-spp-phase-out-weis-new-market-offerings-expand/.

445. D.C. Circuit Remand Order, *supra* note 252, at 1113.

markets comply with the requirements of Order Nos. 888 and 2000. Compliance will look slightly different for each type of market, but future market proponents may be more likely to receive approval from FERC and reviewing courts if they use prior market approvals as a guide.

For each of the existing energy imbalance markets, compliance with the market requirements set out in Order Nos. 888 and 2000 may have been simplified by the fact that despite being non-RTO markets, both the EIM and SPP's WEIS Market benefit from the underlying RTO governance and market monitoring frameworks of CAISO and SPP. For example, although participation can be decided on a BAA-by-BAA basis and participants in each energy imbalance market retain operational control of their resources, both market proposals established representative governing bodies and relatively open stakeholder processes.

For enhanced bilateral energy markets, Order No. 888 provides more guidance than Order No. 2000. Both the PSCo JDA and SEEM, as proposed, retain the bilateral nature of short-term energy transactions. Although the PSCo JDA established a menu of set prices that differed depending on whether participating utilities were net long, net short, or neutral for their short-term energy supplies and SEEM uses midpoint pricing for all energy exchanges, participants in both markets pay each other directly for energy, rather than the market operator settling and billing transactions. Enhanced bilateral frameworks therefore depend on energy being delivered in accordance with each participant's OATT. Governance structures, however, may not need to be as formalized as for those markets operated or administered by RTOs. When the PSCo JDA was established, for example, participation was limited to LSEs only and any prospective LSE needed either to provide or to secure reciprocal transmission to participate. SEEM, in contrast, allowed a wider group of resources to access its platform, requiring only that participants control either a source or a sink within the market footprint and execute trading agreements with prospective counterparties. Unlike for the PSCo JDA, SEEM participants were not required to furnish their own transmission service.

For day-ahead energy markets, the model is still evolving, with only CAISO's EDAM having been approved to date and SPP's Markets+ pending before the Commission, but the importance of must-offer requirements to operating competitive and efficient day-ahead markets may remain a focus going forward. In EDAM, for example, all resources in a participating BAA must either bid or self-schedule their output for the following day and must either reserve unused transmission or pay a standard transmission charge for the delivery of that energy. Especially as the resource mix continues to transition to a higher penetration of duration-limited resources and system net load peaks get steeper, customers and regulators may pay even more attention to safeguards against the exertion of market power and other market-based tools to ensure rates are just and reasonable.

Despite the lessons learned from prior market approvals, several open questions remain about exactly what the Federal Power Act's "just and reasonable" standard requires of new markets, especially regarding participation requirements and governance. If the D.C. Circuit determines that transmission offered at a $0/MWh rate must be considered a discounted transmission rate under Order No. 888, for example, that decision could require SEEM to restructure substantially.

Market monitoring, furthermore, has never been required formally of non-RTO markets, but providing monitoring and implementing other transparency measures may help new market proponents garner support from potential participants and other regional stakeholders.

Nevertheless, the pressures mentioned in this article's introduction—to save customers money, to integrate an increasing amount of new generation onto the grid, and to pursue decarbonization goals—likely will continue to encourage states across the country to explore regional markets. Even states in regions that historically have declined to join RTOs may continue to pursue non-RTO organized markets to capture the lower costs, greater resilience, and potential environmental benefits that operating resources across a wider geographical footprint offers.

Prospective market operators have already convened extensive stakeholder processes to discuss the formation of several new markets, including an expansion of SPP's integrated marketplace to utility service territories in the western interconnect, currently named "RTO West,"[446] and the West-Wide Governance Pathways Initiative.[447] These and other future markets may benefit from addressing potential concerns of FERC and reviewing courts in advance by using existing market designs in each of the three categories as a template and including detailed justifications for why any decisions to deviate from previously-accepted market designs comply with the Federal Power Act and Commission precedent.

446. *RTO West*, SW. POWER POOL, https://spp.org/western-services/rto-west/ (last visited Jan. 15, 2024).

447. *West-Wide Governance Pathways Initiative*, W. INTERSTATE ENERGY BD., https://www.westernenergyboard.org/wwgpi/ (last visited July 7, 2024).