UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket No. ER22-797-000

COMMENTS OF THE ENERGY TRADING INSTITUTE

Pursuant to the comment date established by the Federal Energy Regulatory Commission's ("FERC" or "Commission") Notice for the above-captioned proceeding,[1] Energy Trading Institute ("ETI")[2] hereby files these comments in this proceeding regarding the January 10, 2022 filing submitted by PJM Interconnection L.L.C. ("PJM") proposing revisions to the PJM Open Access Transmission Tariff ("Tariff") and the Amended and Restated Operating Agreement of PJM ("Operating Agreement") to revise PJM's Auction Revenue Rights ("ARR") and Financial Transmission Rights ("FTR") market rules in order to implement several market design enhancements based on the independent analysis conducted by London Economics International LLC ("LEI") and a robust two year stakeholder process.[3]

ETI supports PJM's Tariff filing and respectfully requests that the Commission approve PJM's filing for the reasons discussed below and presented in the accompanying testimony of Dr. Roy J. Shanker, Ph.D on behalf of ETI.[4] Further, ETI respectfully requests that the Commission reiterate its long standing precedent regarding the importance of FTRs as an essential element of

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[1] Combined Notice of Filings #1, PJM Interconnection, L.L.C., *Auction Revenue Rights and Financial Transmission Rights Tariff and Operating Agreement Revisions*, Docket No. ER22-797-000 (Jan. 10, 2022).

[2] ETI timely intervened in this proceeding on January 11, 2022.

[3] PJM Interconnection, L.L.C., *Auction Revenue Rights and Financial Transmission Rights Tariff and Operating Agreement Revisions*, Docket No. ER22-797-000 (filed Jan. 10, 2022) ("PJM Tariff Provisions").

[4] Exhibit No. ETI-1, Testimony of Dr. Roy J. Shanker, Ph.D; Exhibit No. ETI-2, Curriculum Vitae of Roy J. Shanker, Ph.D.

the overall LMP market design in RTO/ISO markets as the financial equivalent of firm transmission in an LMP system.

I. COMMUNICATIONS AND CORRESPONDENCE

ETI requests that the following names to be placed on the service list for this proceeding, and that all correspondence and communication with respect to this proceeding be addressed to the following:[5]

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II. BACKGROUND

FTRs are essential financial instruments linked to the physical capacity of the transmission network that afford Market Participants the capability to hedge the costs associated with day-ahead transmission congestion. As such, they serve a key role in the market design of RTO markets based on LMP, and function as the financial equivalent of firm transmission service. Relatedly, ARRs are entitlements allocated annually to firm transmission service customers that entitle the holder to receive a specified allocation of the revenues from the Annual FTR auction. ARR entitlements in PJM have been related in general to the customers' historic use of the transmission system. ARR holders have the capability to convert ARR positions into FTRs during the Annual FTR auction.

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[5] Persons denoted with an asterisk (*) are those designated for service pursuant to 18 C.F.R. § 385.2010.

PJM developed this proposal of enhancements to the ARR/FTR paradigm with substantial stakeholder input and support through the ARR/FTR Market Task Force ("AFMTF"). In August 2020, PJM hired London Economics International (LEI) to conduct an independent third-party holistic review of the ARR/FTR market.[6] The LEI Report and subsequent joint proposal from multiple stakeholders addressing LEI's recommendations, market monitor concerns, and other stakeholder feedback formed the basis of PJM's proposed revisions herein. The AFMTF considered all potential changes, including a wholesale redesign, with a specific focus on whether or not consumers are reaping the benefits of these markets. The conclusion after a robust two-year process confirmed existing Commission precedent and demonstrated that the markets are working as intended and provide significant benefits to consumers.

According to PJM, the proposed revisions are constructed around two themes: equity and efficiency. The equity-focused revisions are meant to address the primary concern that the ability for some load to efficiently hedge congestion costs can be adversely affected at times when a misalignment occurs between the allocations of congestion rights (i.e., ARRs) and congestion charges paid by load (i.e. there may be a better (sic more equitable) allocation of the FTR auction revenues). The efficiency-focused revisions contain features intended to advance the efficiencies of the FTR auctions, and include changes to enhance market liquidity and future price discovery, both of which add value and contribute to a robust, competitive markets that benefit consumers.

Specifically, PJM proposes the following ARR/FTR enhancements:

1. Revising Operating Agreement, Schedule 1, section 7.4.2 and parallel section of Tariff, Attachment K-Appendix to expand the source/sink combinations permitted in the ARR allocation process to help prioritize directing congestion revenues to load and enhance alignment of ARRs to congestion paid through Congestion

[6] *Review of PJM's Auction Revenue Rights and Financial Transmission Rights,* London Economics International LLC (Dec. 16, 2020), https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/postings/lei-review-of-pjm-arrs-and-ftrs-report.ashx ("LEI Report").

Locational Marginal Prices billing, and make related revisions to streamline the ARR allocation process while accommodating additional source/sink combinations ("ARR Source/Sink Expansion");

2. Modifying Operating Agreement, Schedule 1, sections 5.2.2, 7.4.2, 7.5, and 7.6 and parallel provisions of Tariff, Attachment K-Appendix governing the creation of Stage 1 ARRs to replace the concept of "Zonal Base Load" with a standard of 60% of network service peak load in order to protect zonal native load hedging ability with additional up-front capability ("Stage 1 ARR 60% Load Standard");

3. Revising Operating Agreement, Schedule 1, section 7.1.1 and parallel section of Tariff, Attachment K-Appendix to provide additional self-scheduling options ("Self-Scheduling Flexibility");

4. Revising Operating Agreement, Schedule 1, section 7.8 and the parallel section of Tariff, Attachment K-Appendix to ensure source/sink combinations are limited to valid Stage 1 ARR paths for the customer funded Incremental ARR ("IARR') option in order to help ensure that that new IARRs, which can be administratively burdensome to administer, create value by enhancing market efficiency on valid, useful paths ("ARR Path Validity Requirement");

5. Revising Operating Agreement, Schedule 1, sections 7.1.1, 7.1A.3, and 7.3.4 and parallel sections of Tariff, Attachment K-Appendix to create new FTR class types (and modify the existing types as needed) to provide for on-peak weekday, on-peak weekend and holiday, general everyday off-peak, and 24-hour products, which should increase hedging flexibility for all market participants ("Revised FTR Class Types"); and

6. Adding one sentence to the end of Operating Agreement, Schedule 1, section 7.3.6 and its parallel provision in Tariff, Attachment K-Appendix to create a floor for clearing prices for FTR options, specifically providing that FTR Options with a market-clearing price less than one dollar will not be awarded, which should help ensure that FTR options that are awarded add value to the market ("FTR Option Floor Price").[7]

III. COMMENTS

As elaborated further below, and supported by the affidavit of Dr. Shanker, ETI supports PJM's ARR/FTR revisions as they are consistent with the Commission's statutory obligations and long-standing Commission precedent. PJM's revisions enjoy broad stakeholder support, while the

[7] PJM Tariff Provisions at pp. 5-7.

PJM Independent Market Monitor ("IMM") alternative proposal has been soundly rejected by stakeholders. It is important to note that PJM's proposal passed a sector weighted vote with a score of 3.7 out of 5,[8] while the IMM's proposal received a score of 1.3.[9] The IMM's proposal was rejected by stakeholders because it arises out of a fundamental misunderstanding of the purpose behind the ARR/FTR market design and commercial usage of the products as well as requires impractical assumptions rejected by LEI and the Commission. As discussed below, the LEI Report and the stakeholder process that followed those findings confirmed the significant benefits to consumers as a result of this market structure.

A. ETI Supports PJM's ARR/FTR Revisions That Are Consistent with the Commission's Statutory Obligations and Long-Standing Commission Precedent

Dr. Shanker demonstrates in his affidavit that PJM's proposed ARR/FTR revisions are consistent with the Commission's obligations under the Federal Power Act and long-standing Commission precedent as established with the transmission open access reforms of Order No. 888, and thereafter.[10] Dr. Shanker's affidavit provides an important and instructive history behind the development of FERC jurisdictional competitive power markets, the advancement of power pricing from the flawed contract-path model to the Locational Marginal Price ("LMP") model, and the associated design of FTRs and later ARRs. This background is critical to understanding the legitimacy and importance of these instruments in markets designed with LMP for the respective Independent System Operators ("ISO") and Regional Transmission Organizations ("RTO"), as the Commission has held and as further developed by PJM's current filing.

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[8] PJM Tariff Provisions at p. 1.

[9] *PJM Markets & Reliability Committee Minutes* (as of Oct. 20, 2021), https://pjm.com/-/media/committees-groups/committees/mrc/2021/20211117/20211117-consent-agenda-a-draft-mrc-minutes-10202021.ashx.

[10] ETI-1 at 10-15.

ETI discusses three major areas. First, the development of FTR and ARR instruments as prompted by federal law and Commission precedent; second, ETI expresses its strong support for the Revised FTR Class Types, particularly as they afford market participants greater flexibility to hedge LMP and the congestion component thereof; and third, ETI also expresses its general support for the ARR Source/Sink expansion and Stage 1 ARR 60% Load Standard.[11]

1. FTR and ARR Instruments Developed Pursuant to Statute and Commission Precedent

Originating from the transmission open access principles established by the Energy Policy Act of 1992[12] and later with Order No. 888, the Commission has viewed price signals as essential to promoting "the efficient use of and investment in generation, transmission, and consumption."[13] More specifically, Order No. 888 called for ISO-RTO markets to develop pricing methods for addressing network congestion.[14]

As ISO-RTOs were developing, market participants initially struggled with finding accurate ways to price and reflect the marginal cost of energy supply at locations on the transmission system.[15] As Dr. Shanker explains, the "old" pricing model utilized contract path transmission based rights allowing for the purchase and sale of congestion free supply from a given source to sink.[16] In reality, however, congestion does arise with binding constraints from time-to-

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[11] ETI does not oppose the ARR Path Validity Requirement or the FTR Option Floor Price proposals. *See also,* ETI-1 at 40-42.

[12] Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (1992) § 824.

[13] *Promoting Wholesale Competition through Open Access*, Order No. 888, 75 FERC ¶ 61,080, at p. 284 (1996) (explaining ISO principle 8 to whereby pricing should promote efficiency in investment and use).

[14] Order No. 888 at 284-285 (explaining that ISO pricing policies should reflect a number of attributes, including affording non-discriminatory access to services, ensuring cost recovery for transmission owners and those providing ancillary services, ensuring reliability and stability of the system and providing efficient price signals of the costs of using the transmission grid).

[15] *See* ETI-1 at 15-17.

[16] *Id*.

time due to power flows on the transmission network and this reality is not represented in the contract path paradigm. Thus, relying on the contract path model creates a fallacious pricing assumption leading to inaccurate pricing and cost information to users and, in turn, ineffective hedging mechanisms.[17] Indeed, Order No. 888 recognized the fallacy of contract path pricing, explaining that an alternative pricing model is needed to afford greater flexibility and bring about a "flow-based pricing [to establish] a price based on the costs of the various parallel paths actually used when power flows."[18] Later in Order No. 2000, the Commission recognized the need for "a workable market approach [to] establish clear and tradable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary markets for transmission rights, and provide market participants with the opportunity to hedge locational differences in energy prices."[19]

Ultimately, LMP pricing was developed to correct for the contract path fallacy and more accurately assess marginal cost of meeting demand at the point where load withdraws power from the network (sink) and the point that suppliers and generators inject power in the system (source).[20] Generally, LMP prices an ISO-RTO bus with three components: system marginal energy price, congestion, and marginal losses.[21] Accordingly, LMP pricing provided a methodology to ensure

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[17] *Id*.

[18] Order No. 888 at 44-45, fn 95.

[19] *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285, at p. 333 (1999); inherent in this purpose was the need to be able to fund the congestion between any source and sink pair desired for such equivalent of firm transmission. The source of those funds is the congestion rents (the amount of payments by load in excess of payments to generators). Thus when the "package" of functions of the FTR/ARR market is considered, the hedging function cannot be achieved without returning the congestion rents to those who paid for the transmission system. Indeed the pool of congestion rents reflects exactly the maximum amount that would be needed to fund any feasible set of transmission rights awarded (assuming a constant transmission topology).

[20] ETI-1 at 15-16. *See* also the work of Dr. William Hogan on LMP: https://scholar.harvard.edu/whogan/papers.

[21] ETI-1 at 16.

least-cost dispatch and efficient usage of the transmission system, with FTRs as the design element for market participants and competitors to hedge congestion.[22]

In 2006, the Commission affirmed transmission open access principles, LMP pricing, and the capability to hedge congestion with FTR markets in the implementation of Order No. 681 in response to the statutory obligations of the Energy Policy Act of 2005.[23] The Commission addressed the need to hedge long-term firm transmission rights, ordering that the ISO-RTOs develop FTR tenors of one-year and greater consistent with the statutory objectives of promoting long-term transmission open access.[24] Here, the Commission clearly recognized that the function of FTRs are to serve as a hedge, particularly for congestion.[25] In 2017, the Commission affirmed that FTRs, particularly in the PJM context, serve to provide a congestion hedging function:

> We reject the arguments that the sole purpose of FTRs is to return congestion revenue to load and the market should therefore be redesigned to accomplish that directive. FTRs were designed to serve as the financial equivalent of firm transmission service and play a key role in ensuring open access to firm transmission service by providing a congestion hedging function.[26]

The D.C. Circuit denied petitions to overturn, and thus deferred to the Commission's order rejecting the IMM's arguments.[27]

Dr. Shanker explains, as recognized in 2003, the PJM requirement that ownership of generation as a condition of FTR allocation became unreasonable as the power industry moved away from vertically integrated utility structures with the divestment of generation and opening of

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[22] Order No. 2000 at 382-383; ETI-1 at 15-19.

[23] *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 116 FERC ¶ 61,077 (2006).

[24] *Id*. at 1-2.

[25] *Id*. at 5.

[26] *PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,093 at P 11 (2017).

[27] *New Jersey Bd. of Pub. Utilities v. FERC*, 728 F. App'x 14 (D.C. Cir. 2018).

retail access.[28] Accordingly in this "old" structure, "affiliate companies, now owning the eligible sources, began selling interests in the sources that would enable others to obtain FTRs with that source."[29] To solve this problem, Dr. Shanker proposed to the then PJM executive team the idea of ARRs that were implemented as entitlements allocated annually to firm transmission service customers to entitle the holder to receive an allocation of the revenues from the Annual FTR auction.[30] This would be dependent on historic use or receipt from a source, but not ownership in the source generation.

Over the years, since the introduction of FTRs and ARRs in PJM, there have been several changes to the instruments to improve efficiency, such as, the addition of more FTR paths, an increase in auction frequency, and modifications in how FTRs are settled.[31] Consistent with this long developmental history, LEI has *independently* found that the ARR/FTR construct currently works as designed with only incremental improvements needed.[32] According to the LEI Report of its interviews with stakeholders:

> There was also widespread recognition that Stage 1A of the ARR allocation process helped guarantee some level of "hedge" each planning year. Specifically, LSEs saw the certainty and predictability of Stage 1A and the consistent timeliness of how ARRs are allocated annually and auction revenues from FTR auctions paid out to ARR holders as strengths of the existing design.[33]

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[28] ETI-1 at 24-28.

[29] *Id*. at 25.

[30] *PJM Interconnection, L.L.C.*, 102 FERC ¶ 61,276 at P 7 (2003).

[31] *E.g., PJM Interconnection, L.L.C.*, Docket No. ER06-1218-000 (2006); *PJM Interconnection, L.L.C.*, Docket No. ER07-1053-000 (2007); *PJM Interconnection, L.L.C.*, 156 FERC ¶ 61,180 (2016); *PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,093 (2017); *see* also LEI Report at 25, 112, and 157 in recommending to maintain the current biddable points.

[32] LEI Report at 25-26; PJM Tariff Provisions at 3.

[33] LEI Report at 145.

LEI estimated the benefits of the ARR/FTR construct to approximate in the range of $523 million to $1.2 billion *annually*.[34] The transparency and liquidity of PJM's forward market is due in large part to FTR auctions that have made trading in PJM products highly liquid with one of the lowest bid-ask spreads in US power markets.[35]

2. ETI *Strongly* Supports PJM's Proposal to Expand the Granularity of FTR and ARR Revisions That Are Consistent with Commission Precedent

ETI strongly supports the proposal for Revised FTR Class Types that will expand FTR capabilities for on-peak weekdays, on-peak weekends and holidays, general everyday off-peak, and 24-hour products affording more hedging capability for all stakeholders. Dr. Shanker shares this strong support and explains that this product expansion "can only enhance the efficiency and flexibility of the market".[36] Currently, a solar developer would have to purchase every weekday off peak period to hedge their weekend daytime risk. The Revised FTR Class Type enhancement allows for more granular hedging opportunity as we continue to add intermittent resources. ERCOT implemented an identical product that has been widely used since inception.[37] Further, wind resources typically have higher capacity factors in the overnight hours and will benefit from an off-peak overnight product where they do not need to purchase day-time weekend hours when they hedge their output.

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[34] LEI Report at 92; the estimated benefit is the sum of the estimated lower cost of debt and improved bid-ask spread caused by improved liquidity and ability to hedge wholesale price risks more effectively.

[35] "PJM's liquid markets averaged a bid-ask spread of $0.46/MWh for 2018 and 2019. In comparison, other US RTOs/ISOs had a higher average bid ask spread ranging between $0.49/MWh and $0.66/MWh, reflecting lower liquidity", LEI Report at 87.

[36] ETI-1 at 40.

[37] *See* Electric Reliability Council of Texas, "CRR Time of Use Hours," https://www.ercot.com/mktinfo/crr ("Report showing the CRR Time of Use hours for PeakWD, PeakWE, and Off-peak").

The expansion with Revised FTR Class Types provides more optionality as the "workable market approach [of] clear and established tradable rights for transmission usage … to hedge locational differences in energy prices" as the Commission called for in Order No. 2000. And this proposal is consistent with Order No. 681 in providing more time granularity for FTR settlement along with the short and long-term tenors of the contracts capable of hedging locational price differences and congestion.

3. ETI Supports PJM's FTR and ARR Revisions That Are Consistent with Statute and Commission Precedent with a Recommended Modification

ETI is supportive of the ARR Source/Sink Expansion and the Stage 1 ARR 60% Load Standard as both will continue to advance the objective of allocating the majority of the useful system capability and the associated revenues to ARR holders. As Dr. Shanker believes "that in general, pushing as much of [surplus] allocation into the ARR allocation process to present the preferences of eligible ARR holders is desirable."[38]

Along these lines, as explained by LEI, the ARR Source/Sink Expansion will "prioritize directing congestion revenues to load by providing load with the first rights to the transmission system before FTR Holders can purchase such rights" with more sources and sinks providing more accurate allocation.[39]

Also, replacing the current zonal base load allocation and focusing on 60% of network service peak load would help "protect zonal native load hedging ability with additional up-front capability" under the Stage 1 ARR 60% Load Standard.[40] As recommended by LEI and proposed

[38] ETI-1 at 39.

[39] PJM Tariff Provisions at pp. 7-8.

[40] PJM Tariff Provisions at pp. 8-9.

by PJM this enhancement would also help reduce excess congestion and help mitigate against overallocation of ARRs.[41]

Additionally, Dr. Shanker believes that greater flexibility and allocation of ARRs combined with the ARR Source/Sink Expansion and the Stage 1 ARR 60% Load Standard would help place a more natural limit on resulting low price FTR options in reducing their occurrence.[42]

B. The PJM ARR/FTR Enhancements Gained Broad Stakeholder Support

PJM's proposed ARR/FTR revisions enjoys broad stakeholder support as demonstrated by a sector-weighted endorsement vote of 3.74 out of 5 at the Markets and Reliability Committee and 3.73 out of 5 at the Members Committee.[43] Additionally, the PJM Market Implementation Committee ("MIC") minutes note that stakeholders endorsed this proposal with 244 (84%) of members in favor, 47 (16%) opposed, and 2 abstentions.[44]

In contrast, PJM stakeholders broadly rejected the proposal by the PJM Independent Market Monitor ("IMM") with a sector-weighted endorsement vote of 1.3 out of 5.[45] The overwhelming support for the ARR/FTR Enhancement Revisions represent an endorsement of the position that the proposed ARR/FTR Enhancement Revisions will constitute an improvement from the status quo.

Membership voting was very much in line with the findings of the LEI Report that LSEs generally like many aspects of the existing ARR process which affords tremendous flexibility for

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[41] *Id.*

[42] ETI-1 at 39.

[43] PJM Tariff Provisions at 1.

[44] *PJM Market Implementation Committee Minutes* (as of Oct. 15, 2021), https://www.pjm.com/-/media/committees-groups/committees/mic/2021/20211006/20211006-minutes.ashx at P 1.

[45] *PJM Markets & Reliability Committee Minutes* (as of Oct. 20, 2021), https://pjm.com/-/media/committees-groups/committees/mrc/2021/20211117/20211117-consent-agenda-a-draft-mrc-minutes-10202021.ashx

ARR holders.[46] LSEs have become adept at flexibly using the ARR process as an important congestion management tool and have many options in structuring their portfolio hedges. LSEs can convert their ARRs to known revenue; or convert them to FTRs; or use the ARR revenue to offset purchases of a different set of FTRs from their entitlement that better meets their specific risk tolerance and financial needs; or sell their right; or use their rights as collateral in a bilateral trade; etc.[47] In sum, the current ARR process has commercial value for LSEs that is transparent and easily priced, in contrast to the IMM proposal which will create something that cannot be monetized easily, is not easily tradeable, and is not easily priced.

C. IMM's Proposal Demonstrates a Fundamental Misunderstanding of the Purpose of ARR/FTR and Requires Impractical Assumptions Long Rejected by the Commission

During the stakeholder process in reviewing the ARR/FTR design, the IMM persistently pushed an alternative proposal to replace the existing ARR/FTR construct with a vague and untested allocation system through the AFMTF.[48] In particular, the IMM proposed to: i) eliminate ARR/FTR instruments; and ii) assign the ex post daily congestion surplus to load as a rebate through an obtuse allocation system designed by the IMM involving multiple reference buses and prorations to assign congestion rents. The IMM proposal is a radical departure from Commission precedent and represents a substantial step away from the open access developments initiated by

[46] "LSEs saw the certainty and predictability of Stage 1A and the consistent timeliness of how ARRs are allocated annually and auction revenues from FTR auctions paid out to ARR holders as strengths of the existing design. Furthermore, LSEs echoed non-LSEs' support for the increasing granularity of the FTR product and auction cycle, as well as the rule changes to combat underfunding." LEI Report at 145.

[47] *See* PJM Tariff Provisions at 1.

[48] In summary, the IMM proposes to replace the FTR/ARR construct with a newly invented methodology that directly assigns spot market congestion to load as a rebate based on the actual total congestion collected in both day-ahead and real time energy markets. It is important to note that the network congestion property right's monetary value would only be known after the spot market has settled. Despite two years of IMM presentations on this issue, the exact operations of this assignment methodology remain unclear.

the Energy Policy Act of 1992 and Order No. 888, continuing today, and maintained with the other FERC jurisdictional ISO-RTOs. In essence, the IMM proposal forces the dismantling of the current and highly effected structure and would mean that physical market participants, such as renewable and other suppliers; financial intermediaries that provide trading and risk management services to physical participants; and other participants that add competition and liquidity to the market would be restricted from access to congestion hedges. PJM has long stated that it has an "obligation to ensure the development and operation of market mechanisms to manage congestion" and needs to be able to fulfill that role in a "holistic manner."[49] Establishment of something akin to a bulletin board market not integrated into the PJM market design clearly does not meet this criteria. And most importantly, PJM stakeholders from all sectors have made clear in the outcome of the AFMTF the importance of PJM continuing to fulfill this holistic role consistent with how commercial participants utilize the ARR/FTR market to more cost effectively serve load and finance necessary infrastructure. Naturally, the IMM proposal received *de minimis* stakeholder support with a 1.3 out of 5 on a sector-weighted basis.[50]

At the outset, the IMM's proposal is based on a fundamental misunderstanding of the purpose of FTRs and how Market Participants utilize these products to hedge their risk. The IMM believes the sole purpose of the ARR/FTR construct is limited to the mere returning of congestion to load.[51] This view stands in stark contrast to statutorily driven Commission initiatives and precedent. Again, as the Commission has explained, "[w]e reject the arguments that the sole

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[49] PJM Interconnection L.L.C., *Options to Address FTR Underfunding*, (Apr. 30, 2021), http://ferclitigation.com/wp-content/uploads/FTR-pjm-options-to-address-ftr-underfunding043012-1-1.pdf at P 3.

[50] *PJM Markets & Reliability Committee Minutes* (as of Oct. 20, 2021), https://pjm.com/-/media/committees-groups/committees/mrc/2021/20211117/20211117-consent-agenda-a-draft-mrc-minutes-10202021.ashx.

[51] *ARR/FTR Market Design and Design Components: IMM Proposals*, Monitoring Analytics, (Nov. 17, 2021), https://www.monitoringanalytics.com/reports/Presentations/2021/IMM_MC_ARR_FTR_Market_Design_and_Design_Components_IMM_Propsals.pdf at P 14.

purpose of FTRs is to return congestion revenue to load and the market should therefore be redesigned to accomplish that directive."[52]

Dr. Shanker aptly highlights four material flaws with the IMM proposal. First, at a high level, Dr. Shanker explains that the IMM proposal is just another way to allocate congestion to load, but in a manner completely devoid of any context to the basic Commission objectives regarding firm transmission.[53] Second, by making the settlement of the day-ahead and real-time balancing congestion ***ex post***, the proposal makes it impossible for loads to have any realistic expectation of being able to hedge their specific supply from a designated source via any mechanism tied to the PJM network and market platforms.[54] This occurs because the definition of where the congestion rents to be paid to the load is undefined in advance[55] and only known after the fact. Accordingly, there is no way for these parties to either know their specific entitlement in advance and thus exchange it *ex ante* for a known congestion hedge supported by market congestion results. Third, because of the *ex post* nature, the only feasible hedging would have to occur on a bilateral basis not supported by the PJM market, e.g. to hedge from source A to sink B a party would have to find, external to the PJM markets platform, someone willing to take on the B-A risk.[56] This would result in an inefficient process not tied directly to the PJM market platform and as a result would be more costly to customers. It is also critical to note that bilateral basis markets do currently exist but they rely on the granular pricing provided by the FTR auctions that

[52] 158 FERC ¶ 61,093 at P 11.

[53] ETI-1 at pp. 41-42.

[54] ETI-1 at pp. 44-45.

[55] While a process is specified, the actual inputs and outputs are unknown until after the market clears day ahead and in real time.

[56] ETI-1 at pp. 45.

are directly tied to the PJM market platform. As discussed below, LEI found clear evidence that the volume on Nodal Exchange increased dramatically after FTR market results were posted demonstrating the FTR auctions impact on the futures market. More importantly, these products are vastly different from an FTR product that is tied to simultaneous feasibility being supported by actual market collections of congestion and market platform settlements. Fourth, the inclusion of balancing congestion is simply wrong, and reflects a collateral attack on strong findings and direction previously provided by the Commission noting that there was no reasonable cost causation between the day ahead congestion and congestion rents for FTR holders and the sources of balancing congestion incurred for balancing the system in real-time. This type of provision has previously been soundly rejected by the Commission.[57]

Furthermore, as Dr. Shanker explains, notwithstanding the concern that IMM's proposal is fundamentally misguided, the justification for its proposal is based on a wrong and illogical framing of what it refers to as "leakage".[58] The IMM falsely believes, despite Commission and court precedent, that all congestion paid by load should be returned to load, and any congestion not captured by load participants is leakage and ought to be corrected. While on its face this argument may appear attractive, it completely disregards the risks taken by *non-load participants* in acquiring the FTRs and the competitive process by which they are acquired. The only way a non-load participant can receive FTRs is to pay for them, and pay at a competitive market price.[59] They can do so in the auctions, where they compete with other third parties, but much more

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[57] *PJM Interconnection, L.L.C.*, 156 FERC ¶ 61,180 (2016).

[58] ETI-1 at 34-38.

[59] "The MMU concludes that the PJM FTR auction market results were partially competitive in 2020." *State of the Market Report for PJM*, Monitoring Analytics, LLC (Mar. 3, 2021), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-vol2.pdf at 10.

importantly for this discussion, they also compete with load serving entities that may or may not have ARRs. The purchase of FTRs therefore requires a willing seller being happier with a fixed payment from a third party (an LSE or anyone else) in exchange for its ARR position (that can then be converted to an FTR), or when an LSE is facing a competitor for the right of interest, being outbid for it. Simple difference in risk profiles would justify fixed for variable swaps of some of the ARR positions held by LSEs in exchange for cash, instead of the receipt or holding of the associated FTR. The FTRs will always wind up with the "right" parties based on willingness to pay. The congestion captured by non-load participants based on such exchanges is therefore reflective of the risks they have taken; it is not an economic loss.[60]

D. The Benefits Provided To The End Customer Through The Value And Cost Savings Of FTRs Today And As We Integrate Additional Renewable Assets And Upgrade Aging Infrastructure

The LEI independent analysis highlighted several key findings. First, LEI tested whether the participation of non-load entities in the FTR auctions improves FTR's predictive power of day-ahead congestions.[61] LEI relied on a simulated auction results provided by PJM (as part of the PJM ARR/FTR White Paper analysis, PJM recreated FTR auction prices for planning period 2017/18 if no financial participants (i.e., non-load) traded FTRs). Comparison of the statistical properties of the simulated and actual auction results at predicting day-ahead congestion shows that the actual FTR auction, which includes both load and non-load participation, has a better predictive power of day-ahead congestion than the simulated auction results with "no financial

[60] ETI-1 at 36-38 (explaining that the ARR/FTR design is "exactly the type of Coasian adjustment/trading that one would expect in a low friction exchange market" where "FTRs will always wind up with the 'right' parties based on willingness to pay"); *see also*, *See* Coase, R., 1960. The Problem of Social Cost. The Journal of Law and Economics, 3, pp.1-44 (establishing what is now called the "Coase Theorem" where efficient market solutions arise from clear and complete property rights with little to no transaction costs).

[61] LEI Report at pp. 12-14.

participation."[62] This indicates that non-load participation improves the price discovery feature of FTR auctions.

Second, LEI's analysis of hedging activity related to financing of new generation demonstrates that developers and their commercial partners rely on the forward market to make critical investment decisions and assess the cost of financing. The extensive use of financial hedges is another measurable reference point for the importance of forward market activity in creating long term benefits to load. LEI surveyed the financing arrangements of new gas-fired resources that entered commercial operation for the last three years in PJM. LEI's research confirmed that nearly 9.5 GW of new combined-cycle gas turbine ("CCGT") capacity that started commercial operations from 2017 to 2019 involved using financial hedges as part of their financing arrangements. These financial hedges were realized thanks to liquid forward markets. Furthermore – and importantly for the purpose of estimating long term benefits – market price risk associated with the financing of these investments was reduced as a consequence of these financial hedges.[63]

Third, LEI found that FTR auctions are directly correlated to forward market activity. To understand how PJM FTR market activities influence the forward market, LEI worked with Nodal Exchange to examine trends in volumes of basis-related futures right after PJM FTR auction result are published. The data indicates that volumes of futures traded on Nodal Exchange increase significantly after each FTR auction. The uptick in volumes indicates the presence of price discovery process and influence of FTR auctions over futures activity in PJM.[64]

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[62] *Id*.

[63] LEI Report at 15.

[64] LEI Report at 74-75.

Fourth, LEI found that the path-based construct provides solid price signals and is directly linked to bilateral arrangements. LEI considered to what extent the path-based construct (of FTRs and ARRs) is relevant to bilateral arrangements. The path-based construct of FTRs provides an ability to perfectly hedge congestion risk at a nodal level.

> A review of transactions associated with bilateral energy contracts reported to FERC's Electric Quarterly Reports ("EQR") database shows that in the past five years (2015-2019), over 35% of the value of physical contracts with delivery in PJM used a node (instead of a hub, zone, or aggregate) as the delivery point. Transactions with nodal-based delivery points were reported to have a cumulative transaction value of over $75 billion over five years. Moreover, in the past two years, the share of transactions using nodes as a delivery point has increased to over 50% (in value terms, or $26 billion on average per annum). This fact indicates the market's overall confidence in using nodes as a commercial pricing point.[65]

Lastly, at the beginning of the ARR/FTR Task Force several load serving entities articulated that the FTR product is critical for their ability to offer fixed priced contracts to their customers at a reasonable cost because they are able to hedge their future congestion risk via the FTR auctions.[66]

In short, LEI found that FTR auction results provided a granular understanding of expected congestion, which in turn allows market participants to hedge congestion risk more effectively. Further, the price discovery emanating from the FTR auctions supports liquidity in the forward markets, which reduces the cost of hedging and bilateral contracting. Therefore, in the long run load benefits from a liquid and efficient forward market through lower transaction costs, lower financing costs and optimal reallocation of risk.[67] These conclusions are confirmed by LEI's

[65] LEI Report at 15.

[66] *See Load Serving Entities' Perspective on PJM ARR/FTR Market Design* (May 27, 2020), 20200527-item-04-load-serving-entities-perspective-on-afmtf-design.ashx (pjm.com); *Load Serving Entities' Perspectives on PJM ARR/FTR Market Design* (June 25, 2019), https://www.pjm.com/-/media/committees-groups/task-forces/frmstf/20190625/20190625-item-05-load-serving-entities-perspectives-on-arr-ftr-market-design.ashx.

[67] LEI Report at 15-17.

findings that the FTR market saves customers anywhere between $523 million to $1,207 million on annual basis. And this information is validated by presentations provided by Exelon, NextEra, PSEG and Direct Energy at the start of the FTR/ARR Task Force, who serve a substantial amount of the load in the US, stating they would be unable to offer their customers fixed price contracts at current rates without the ability to hedge their congestion risk in the FTR market. The IMM proposal would rob Market Participants and, more importantly, customers of all of the benefits our industry has worked to achieve over the past two decades. As various states pursue aggressive renewable standards, corporations seek to meet new ESG goals, and we work to replace aging infrastructure to maintain reliability, it is critical that buyers and developers have the appropriate tools to hedge against their potential congestion risk. As demonstrated by LEI, a significant amount of new generation developed in PJM utilized FTRs as a necessary provision to obtain financing. Simply put, without proper hedging mechanisms, these units either would not have been able to obtain financing or would have incurred a higher financing cost, which results in higher costs for customers.[68] The IMM proposal makes all of this near impossible and extremely inefficient. Further it completely eliminates PJM's ability to facilitate such transactions based on is market congestion revenues and market platforms.

IV. CONCLUSION

For the reasons discussed above, ETI respectfully requests that the Commission approve PJM's proposed Tariff revisions as proposed. Further, ETI also kindly requests that the Commission reiterate its long-standing precedent on the value of FTRs so that consumers may continue to benefit from the tremendous cost savings provided by these products..

Dated: January 31, 2022

[68] *Id*.

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Attorneys for ETI

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington D.C. this 31st day of January, 2022.

/s/ Jimmie Zhang

Jimmie Zhang
Sidley Austin LLP
1501 K Street, N.W.
Washington, DC 20005

Exhibit ETI-1

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket No. ER22-797-000

AFFIDAVIT OF ROY J. SHANKER PH.D

ON BEHALF OF

ENERGY TRADING INSTITUTE.

January 31, 2022

Roy J. Shanker Ph.D.

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Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Roy J. Shanker. My address is P.O. Box 1480, Pebble Beach California, 93953.

I. QUALIFICATIONS

Q. CAN YOU PROVIDE A BRIEF SUMMARY OF YOUR BACKGROUND AND PARTICIPATION IN WHOLESALE POWER MARKETS AND THE DESIGN OF THESE MARKETS?

A. A copy of my resume is attached as Exhibit No. ETI-2. It provides a full description of my education, work experience and various legal and regulatory proceedings where I have testified as an expert with respect to electric utility matters and markets.

I first began working on energy related matters in October, 1973, and started to focus my work primarily on the electric utility industry in approximately 1976-77. I started my independent practice in 1981, with the vast majority of my work concentrated in the electric industry since that time. In over 700 engagements I have worked for virtually every sector that relates to the industry: regulators, vertically integrated utilities, Qualifying Facilities and Independent Power producers, lenders and investors in capital equipment; equipment manufacturers, constructors/engineers, trading organizations, and in some cases combinations or coalitions of these various types of parties and other market participants and stakeholders. I have appeared a number of times as a witness and as an invited speaker before the Commission. Specific to the general transmission rights addressed in this proceeding, I have addressed FTR or related transmission rights in Commission Dockets: EL20-49, EL18-1334, EL16-6, ER16-21 (submission and technical session), ER-14-1579, ER12-715 (twice), IN12-4, EL11-56, ER11-2059, ER0-456, EL07-67, ER-03-406 (re ARR creation), IN01-7, RM01-12, ER97-1523, A97-470, ER97-1082, and OA97-261. I have also addressed related issues in state and federal court proceedings, including those related to trading in the congestion rights market in general and the Greenhat default in particular.

With respect to PJM I have been involved in the stakeholder process since the beginning of the market development process (approximately 25-26 years), and as discussed below participated in virtually all of the issues related to the current ARR/FTR market. I believe I was the original party to suggest the ARR structure as a mechanism to transition out of PJM's then current FTR only design. I had similar participation with respect to the TCC design in NYISO and to a lesser extent with the CRR construct in CAISO.

In terms of this specific proceeding I have been involved in all of the review processes of the ARR/FTR markets that PJM has conducted since it began its market review following the Greenhat default. This includes market modifications that have already taken place with respect to collateral/security changes in the market, the Risk Management Committee (addressing further adjustments and enhancements to security in the ARR FTR market), and of course the ARR FTR Market Task Force where the proposals filed by PJM were discussed and developed. I also participated in the previous FTR ARR Task Force process.

Q. WHAT IS THE PURPOSE OF YOUR FILING IN THIS PROCEEDING?

A. I was retained by the Energy Trading Institute (ETI) to review and comment on PJM's filing in this proceeding as well as some related issues that were raised in the ARR FTR Market Task Force. Specifically, I will be addressing five areas:

- The background and regulatory actions of the Federal Energy Regulatory Commission (FERC/the Commission) with respect to financial transmission rights and their function in organized wholesale markets such as PJM;
- PJM's historic actions related to the design of the auction revenue rights/financial transmission rights (ARR/FTR) markets.
- The London Economics International (LEI Report)
- Specific elements of the PJM filing proposal and my related findings/conclusions and;
- Problematic elements of the proposal and design elements that have been offered by the Independent Market Monitor (IMM) and their potential impacts on limiting open access, competition, and liquidity.

II. CONCLUSIONS

Q. WHAT WERE THE MAIN CONCLUSIONS YOU REACHED BASED ON YOUR PERSONAL AND PROFESSIONAL EXPERIENCES?

A. I came to four principal conclusions:

First: The primary themes driving the development of regional transmission organizations through actions of the Congress and the Commission related to enhancing competition (and thus efficiency) in the electric markets via open access to transmission.

- The Commission had related concerns addressed maintaining the ability to hedge electric supplies by retaining and honoring some form of firm transmission which ultimately became manifest as FTRs.
- The use of LMP offered a means to address both of these concerns, but assuring least-cost dispatch and efficient usage of the transmission network, while also creating a

surplus of funds (the congestion rent surplus, or congestion funds) that reflected payments by load in excess of receipts by generators/suppliers. In turn a derivative concern was an equitable manner to deal with the distribution of this surplus. FTRs were a key to preserving the right prices, offering the financial equivalent of firm transmission and simultaneously distributing excess congestion rents. In this manner the surplus represented the exact same amount needed to fund such financially firm transmission if the system were fully utilized.

Second: PJM's original market design was driven by both of these features. There was enormous concern by the original Supporting Companies and PECO[1] to find mechanisms to retain the historic supply arrangements based on their specific investments in transmission, particularly newer high voltages facilities that were jointly owned, and that serviced jointly owner generation while at the same time finding the best (least cost) commitment and dispatch of the market resources to minimize costs. When finally adopting a locational marginal pricing design, an integral part of achieving these objectives was the implementation of the original (and evolving) FTR market design. This ensured both efficiency and open access to transmission while simultaneously protecting important long term transmission investment and associated benefits to the then existing load.

Third: PJM's filing in this proceeding reflects part of a continuing enhancement of the current ARR/FTR consistent with these original Commission objectives (and consistent with the conclusions of the review by LEI, Inc.). The AFMTF's purpose was to reevaluate

[1] The original PJM filing was by eight of the original vertically integrated utilities (collectively Supporting Companies) and PECO. This partition reflected disagreement on the LMP system that was ultimately adopted. See 81 FERC ¶ 61,257 (1997).

whether the ARR/FTR design benefitted consumers. Its charter made clear that any potential reform was on the table, including even elimination of the FTR/ARR construct entirely, as the IMM had been arguing for some time, or other reforms to restrict or enhance the product to benefit customers. As such, the overwhelming stakeholder consensus in favor of the extant filing represents a ratification and confirmation of the original market objectives delineated by the Commission and PJM, in terms of better meeting the overall goals. This is consistent with the broad charter of the ARR FTR Market Task Force to evaluate and in turn enhance the market design where possible.

Fourth: The suggested changes by the IMM are a "non-starter". The IMM proposal focuses only on a narrow view of the issue of allocation of excess congestion rents and completely ignores the fundamental objective of open access to transmission and the related enhancement of hedging by consumers of their supply arrangements. The proposal suggested by the IMM (and rejected by stakeholders) actually makes such hedging within the context of actual market congestion rents and nodal pricing virtually impossible (and drastically less efficient). As simple a task as obtaining firm point to point transmission service would not be possible. Indeed my conclusion would be that the only possible hedging would be undifferentiated from an inefficient "over the counter" (OTC) bilateral arrangement that any party could implement and be incapable of reflecting network effects, which is the core strength of the ARR/FTR construct approved by the Commission.

Q. WHAT RECOMMENDATIONS WOULD YOU MAKE TO THE COMMISSION BASED ON THESE CONCLUSIONS?

A. I have two main recommendations:

First, I would recommend that Commission accept the PJM submission and proposed tariff changes. I note that I make no recommendation regarding the changes proposed for Schedule 1 Section 7.8 regarding incremental auction revenue rights. (PJM Enhancement 4)

Second, I would reject any efforts now or in the future to modify the filing in a manner as suggested by the various proposals that the IMM has put forward in the stakeholder process. I believe that the best way the Commission can do this in the context of this Section 205 filing is formally ratify the underlying Commission precedents that I cite that supports these proposed PJM enhancements, and once again reject the myopic perspective expressed by the IMM.

III. CONTEXT: THIS FILING

Q. COULD YOU PUT THE PJM FILING IN CONTEXT IN TERMS OF RECENT EVENTS IN THE PJM ARR/FTR MARKET?

A. At the request of Organization of PJM States, PJM initiated the ARR FTR Market Task Force (AFMTF). "The ARR FTR Market Task Force (AFMTF) will conduct a comprehensive review of the ARR/FTR market design including allocation of congestion rights, FERC objectives, value proposition, and opportunities for enhancements."[2]

On a separate track, it was also recommended that PJM undertake an independent review of the ARR/FTR market as well. PJM conducted its own review and prepared a report on the functioning of the ARR/FTR market and its performance. This was presented to stakeholders in April, 2020 (the PJM White Paper).[3] In the White Paper, PJM presented

[2] See PJM, ARR FTR Market Task Force, https://www.pjm.com/committees-and-groups/task-forces/afmtf (note that this is different than PJM's previous ARR FTR Senior Task Force circa 2014).
[3] *Financial Transmission Rights Market Review* (April 2020), https://www.pjm.com/-/media/library/reports-notices/special-reports/2020/ftr-market-review-whitepaper.ashx.

its own internal findings with respect to the structure of the market and the effectiveness of the market , particularly how well the market performed in returning excess congestion rents to market participants as well as providing a robust and liquid platform that would allow market participants to hedge their risks in the energy market.

Also at stakeholder urging, PJM undertook a separate independent market review. In this context PJM retained London Economics International LLC (LEI) to perform a study on the ARR/FTR market, its objectives, function and to also make recommendations for potential improvements. This report (LEI Report) was delivered on December 16, 2020 and updated on January 22, 2021.[4]

Within the stakeholder process, the PJM White Paper, the LEI Report, as well as comments and recommendations of other market participants were reviewed and discussed in the ARR FTR Market Task Force (AFMTF). As discussed below the LEI report again confirmed the basic PJM ARR/FTR market design, but also identified a set of recommendations that form the basis of the PJM proposed enhancements.

PJM's proposal, which received overwhelming support in the stakeholder process, represents one of several packages or combinations of recommended actions that were discussed in the AFMTF.

IV. CONTEXT: ISO/RTOs AND FINANCIAL TRANSMISSION RIGHTS

[4] *Review of PJM's Auction Revenue Rights and Financial Transmission Rights*, London Economics International LLC, (Dec. 16, 2020), https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/postings/lei-review-of-pjm-arrs-and-ftrs-report.ashx.

Q. WHAT WERE THE INTENDED PURPOSES OF FORMING INDEPENDENT SYSTEM OPERATORS (ISOs) AND REGIONAL TRANSMISSION ORGANIZATIONS (RTOs)?

A. The Commission is obviously familiar with all of its orders and this history, but it does serve to take a very high-level review of what has happened to give context to the basic functions and objectives of PJM's ARR/FTR market and how the PJM proposal in general complements and furthers those objectives.

Congress, via amendments to the Federal Power Act (FPA), and in turn the Commission, through associated rulemakings and orders, has pursued enhanced efficiency in the wholesale electric markets via the introduction of competition on multiple occasions. ISOs and RTO's are just one element in a long string of actions.

From my perspective these actions began with the Public Utility Regulatory Practices Act in 1978. In hindsight, this was a small but very material step towards the competitive structures we see today. Competition in supply and a "bite" into open access was introduced through a formal mandate of utilities to purchase from and interconnect with Qualifying Facilities.[5]

The next much larger step occurred with the passage of the Energy Policy Act of 1992. (EPACT92).[6] EPACT92 directly amended the FPA section 211 to increase competition in wholesale energy markets through open access to transmission:

SEC. 721. AMENDMENTS TO SECTION 211 OF FEDERAL POWER ACT.

Section 211 of the Federal Power Act (16 U.S.C. 824j) is amended as follows:

(1) The first sentence of subsection (a) is amended to read as follows: `Any electric utility, Federal power marketing agency, or any other person generating electric

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[5] *See e.g.*, 18 C.F.R. § 292.303 (a) and (c).
[6] Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (1992) § 824.

> energy for sale for resale, may apply to the Commission for an order under this subsection requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant.'.

> (2) In the second sentence of subsection (a), strike `the Commission may' and all that follows and insert `the Commission may issue such order if it finds that such order meets the requirements of section 212, and would otherwise be in the public interest. No order may be issued under this subsection unless the applicant has made a request for transmission services to the transmitting utility that would be the subject of such order at least 60 days prior to its filing of an application for such order.'.

In turn in April of 1996 the Commission followed Congress' direction with Order 888 (Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities. Again, a primary goal was the efficiency gains of competition in markets being expanded by open access to transmission, and complimented by Independent System Operators. The Commission saw direct and material gains from efficient supply platforms.

> Today the Commission issues three final, interrelated rules designed to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers. The legal and policy cornerstone of these rules is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce.…[7]

> The Commission estimated that the Final Rule had the potential benefits of between $3.8 to $4.5 billion of quantifiable benefits.[8]

Order 888 was also very supportive of the concept of ISOs as part of the overall efficient and competitive landscape. They directly recognized the importance of ISO's structure and offered guidelines directed at efficient price signals, and linking this with network congestion pricing and management.

[7] *Promoting Wholesale Competition through Open Access*, Order No. 888, 75 FERC ¶ 61,080, at p. 1 (1996).
[8] *Id*. at 3.

> In particular, we believe that ISOs have great potential to assist us and the industry to help provide regional efficiencies, to facilitate economically efficient pricing, and, especially in the context of power pools, to remedy undue discrimination and mitigate market power.[9]

> The Commission recognizes that some utilities are exploring the concept of an Independent System Operator and that the tight power pools are considering restructuring proposals that involve an ISO. While the Commission is not requiring any utility to form an ISO at this time, we wish to encourage the formation of properly-structured ISOs. To this end, we believe it is important to give the industry some guidance on ISOs at this time. Accordingly, we here set out certain principles that will be used in assessing ISO proposals that may be submitted to the Commission in the future….[10]

> [Principle] 8: An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions. Appropriate price signals are essential to achieve efficient investment in generation and transmission and consumption of energy. The pricing policies pursued by the ISO should reflect a number of attributes, including affording non-discriminatory access to services, ensuring cost recovery for transmission owners and those providing ancillary services, ensuring reliability and stability of the system and providing efficient price signals of the costs of using the transmission grid. In particular, the Commission would consider transmission pricing proposals for addressing network congestion that are consistent with our Transmission Pricing Policy Statement.[11]

The Commission consolidated many of these pieces in Order 2000 in 1999.[12] In one statement they put in place the conceptual bases for the elements we see in virtually all of today's RTO's: the direct support of the value of forming and joining RTO's, open and non-discriminatory access, locational marginal pricing, and financial transmission rights as the consistent financial representation of firm transmission to complement the hedging of traditional supplies. This last element was the penultimate objective and its explanation is expanded below. The Commission also set 12 minimum characteristics and functions

[9] *Id*. at 52.
[10] *Id*. at 279.
[11] *Id*. at 284-285.
[12] *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285 (1999).

that a transmission entity must satisfy in order to be considered an RTO. "The regulations require that each public utility that owns, operates, or controls facilities for the transmission of electric energy in interstate commerce make certain filings with respect to forming and participating in an RTO. The Commission's goal is to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service."[13] The major attributes of the current market design achieve these goals: LEI explicitly quantifies the hundreds of millions of dollars of benefits to consumers realized under the current design and the associated efficiency brought about by liquidity and competition.[14]

The Commission also clearly saw the FTR design element and its ability to hedge locational price differences as a key element of the markets it envisioned:

> We stated that while it is our intent to give RTOs considerable flexibility in experimenting with different market approaches to managing congestion, we believe that a workable market approach should establish clear and tradable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary markets for transmission rights, and provide market participants with the opportunity to hedge locational differences in energy prices.[15]

In the Order 2000 proceeding PJM also made clear its understanding and objectives in terms of the market design it had just put in place, and the role of fixed transmission rights (later changed to financial transmission rights) to hedge congestion.

> PJM states that the Commission correctly concludes that LMP will "encourage efficient use of the transmission system, and facilitate the development of competitive electricity markets." PJM notes that, under LMP, transmission customers are assessed congestion charges consistent with their actual use of the system and the actual redispatch that their transactions cause. It claims that this provides an economic choice to non-firm transmission customers to self-curtail their use of the transmission system or pay congestion charges determined by the market. PJM believes that by basing congestion charges on the true re-dispatch cost,

[13] *Id.* at 1.
[14] LEI Report at 17.
[15] Order No. 2000 at 333.

> parties behave in a rational and efficient manner. It states that the market determines the clearing price for transmission congestion and which customers ultimately utilize the transmission system. PJM states that the use of fixed transmission rights (FTRs) enables market participants to pay known, fixed transmission rates and to hedge against congestion charges.[16]

The Commission seemed unambiguous in its concurrence regarding PJM specifically and RTOs in general with respect to these hedging functions.

> While we will not prescribe a specific congestion pricing mechanism, we note that some approaches appear to offer more promise than others. As we stated in our order approving the PJM ISO and reiterated in the NOPR, markets that are based on locational marginal pricing and financial rights for firm transmission service appear to provide a sound framework for efficient congestion management…[17]

> In the NOPR, we stated that a workable market approach to congestion management should establish clear and tradable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary markets for transmission rights, and provide market participants with the opportunity to hedge locational differences in energy prices….[18]

> Commission Conclusion

> With respect to congestion pricing, the Commission emphasized that it intends to be flexible in reviewing pricing innovations, and sought comments on what specific requirements, if any, best suited the Commission's RTO goals. A number of commenters agreed with the Commission's conclusion in the NOPR that "markets that are based on locational marginal pricing and financial rights for transmission provide a sound framework for efficient congestion management."[19]

The last step I summarize in this clear evolution of the FTR market function is reflected in direction from the Energy Policy Act of 2005, and the ensuing Order 681. In addressing the issue of long-term transmission rights, the need for a hedge in supply was met head on, and the Commission’s response was direct. It clearly understood the function of the FTR’s to serve as a hedge, and wished to extend the construct into a longer time period. The

[16] *Id.* at 353-54.
[17] *Id.* at 382.
[18] *Id.* at 385.
[19] *Id.* at 525.

Commission's own summary of EPACT05 makes this clear, as well as the Commission's ordering language:

> In addition, the Commission issued a rule to require transmission organizations with organized electricity markets to make available to load-serving entities long-term firm transmission rights that satisfy certain guidelines. This will help customers who want to make long term supply arrangements. These customers want to be able to enter into long term transmission service arrangements without being exposed to un-hedged congestion cost risk. The final rule goes far to reduce the risk exposure to transmission customers, and is important to development of the grid.[20]

> There are several important differences between transmission service under the Order No. 888 pro forma Open Access Transmission Tariff (OATT) and transmission rights in organized electricity markets that use LMP and FTRs. However, the differences that are most relevant for purposes of this Final Rule concern the management of congestion, the recovery of congestion costs and the availability of long-term service arrangements.[21]

> In contrast, a transmission organization in a region with an organized electricity market recovers congestion costs measured as differences in the locational price of energy. Because locational prices include a congestion cost component (which can be positive, negative or zero), a participant in an organized electricity market faces the prospect of paying a congestion charge for many of its transactions. Locational pricing and price-based congestion management provide the market participant with much of the information it needs to make cost effective decisions regarding energy consumption and use of the transmission system (as well as investment in new generation and transmission upgrades). However, the FTRs that transmission organizations currently provide to hedge congestion charges for using existing transmission capacity (as opposed to incremental transmission expansions) are generally available for terms of only one year or less.[22]

> Commission Conclusion

> We will adopt guideline (1) without modification. The primary objective of guideline (1), consistent with section 217(b)(4), is to allow a load serving entity to obtain a long-term firm transmission right for purposes of hedging congestion charges associated with delivery of power from a long-term power supply arrangement to its load. Moreover, as several commenters noted, guideline (1) is

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[20] Federal Energy Regulatory Commission, *FERC & EPAct 2005* (Aug. 8, 2006), https://www.ferc.gov/sites/default/files/2020-04/ferc-and-epact-2005.pdf.

[21] *Long-Term Firm Transmission Rights in Organized Electricity Markets,* Order No. 681, 116 FERC ¶ 61,077 (2006) at P 6.

[22] *Id.* at 8.

> largely consistent with existing designs for FTRs in the organized electricity markets operated by transmission organizations.[23]
>
> Thus guideline (2) as adopted in this Final Rule reads as follows: The long-term firm transmission right must provide a hedge against locational marginal pricing congestion charges or other direct assignment of congestion costs for the period covered and quantity specified. Once allocated, the financial coverage provided by a financial long-term transmission right should not be modified during its term (the "full funding" requirement) except in the case of extraordinary circumstances or through voluntary agreement of both the holder of the right and the transmission organization.[24]

V. <u>THE FUNCTION AND ROLE OF FTRs AND THE CONGRESSIONAL AND COMMISSION POLICY INITIATIVES</u>

Q. WHY WERE FTRs SUCH AN IMPORTANT ELEMENT OF THE ORDERS AND POLICIES YOU CITED ABOVE?

A. Not only do the citations above express the objectives and concerns of the Commission, but FTRs become the integral tool to the market design that allow the achievement of the benefits to consumers that were quantified by LEI. Just looking at the ability to form capital at lower costs due to the efficiencies brought by the FTR market and hedging benefits, LEI estimated a range of savings from $522 million to $1.2 billion per year (This ignored capital cost benefits to retailers). [25]

As the Commission moved forward with the development of the RTO markets, in parallel, the markets themselves adopted more sophisticated and accurate ways of reflecting the marginal cost of energy supply at locations on the transmission network. The "old" pricing was uniform, with contract path (not power flow) transmission based rights

[23] *Id.* at 66.
[24] *Id.* at 88.
[25] See LEI Report at 15-17 and Figure 8. LEI estimates that just the saving from hedging benefits that reduces long run marginal costs and transaction costs could range from a total of $522 mill to $1.2 billion a year excluding retail hedging benefits. Allowing competitive suppliers to offer tighter spreads in activities such as default auction and in turn lowering costs to load (LEI estimates of $424-889 million per year); LEI estimated benefits of $99-318 million per year from lowering the cost of capital and thus long run marginal costs.

allowing for the purchase and sale of congestion free supply from a given source to a sink. But the contract path based mechanism was built on a fallacious view of the network and denied the reality of power flows on the network. This unrealistic view of the underlying physical reality of the system often resulted in transmission loading relief (TLRs) and associated curtailment of firm transmission when constraints bound for a variety of reasons, including loop-flow.[26] The contract path mechanism could not adapt or adjust rapidly to changing uses of the network in terms of injections and withdrawals. Similarly contract path structures were typically conservative in assumptions regarding available transmission exactly because of the lack of specificity about actual network conditions and available transmission capacity, again resulting in under-utilization of the network. This was wasteful in terms of the potential for network capability to be withheld or lost if the reserved contract rights were not utilized.

The contract path fallacy blinded the market participants to the true marginal cost of power and the marginal value of transmission. To achieve the Commission's goal of efficiency, a better mechanism was needed to display the marginal costs to both supply and demand in the market, guiding the dispatch of generation and revealing the marginal costs of power at all locations, and in turn the marginal spot cost of transmission (*i.e.*, the difference between the marginal congestion component at two locations).

LMP met this requirement perfectly. Loads would pay the LMP (*i.e.*, the marginal cost of meeting demand) at the point they withdrew power from the network and generators would be paid the LMP at their point of injection. Thus, both would get the correct price signal and also be aware of the value of transmission on the network. In something of a

[26] Loop flows result from parallel flows outside of the system operators control in adjacent markets/control areas.

chicken and egg process, ISOs and RTOs developed at the same time the more sophisticated locational marginal pricing was gaining traction. Much of this was due to the research and work of Dr. William Hogan and associates (and as noted much of this work, particularly the basic building blocks, preceded the RTO's themselves).[27]

Under LMP, the price at every bus on the system was partitioned into three components: the system marginal energy price (SMP), the congestion component (CLMP) and the marginal loss component (MLMP). Ignoring losses, what was of most interest in terms of transmission rights was the associated ability to hedge transmission congestion costs between two locations on the network. As the electric system dispatch solved for the least expensive use of resources on the system given transmission constraints (the Security Constrained Economic Dispatch or SCED), information was created allowing the determination of the shadow price[28] of each binding transmission constraint in the network.

[27] Dr. Hogan is a prolific writer. See for overview: https://scholar.harvard.edu/whogan/files/hogan_ftr_rev_adequacy_031813.pdf.

See also:

William W. Hogan, *Contract Networks for Electric Power Transmission*, 4 #3, J. Regul. Econs. (1992).

William W. Hogan, *Report on PJM Market Structure and Pricing Rules* (Dec. 31, 1996) (prepared for the PJM Supporting Companies).

William W. Hogan, *Appendices to Report on PJM Market Structure and Pricing Rules* (Dec. 31, 1996) (prepared for the PJM Supporting Companies).

William W. Hogan, *A Wholesale Pool Spot Market Must Be Administered by the Independent System Operator: Avoiding the Separation Fallacy*, Elec. J. (1995).

William W. Hogan, *Report on the Proposal to Restructure the New York Electricity Market* (Jan. 31, 1997) (prepared for the Member Systems of the New York Power Pool).

[28] The shadow price is defined as the incremental reduction in total costs associated with the relief of the associated constraint, e.g. how much overall costs would decline if one more MW of flow could pass over a given constrained transmission facility. The Summary paper of previous finding: https://scholar.harvard.edu/whogan/files/hogan_ftr_rev_adequacy_031813.pdf
"A central feature of the FTR model is the principle of revenue adequacy. The basic definition is that the system is revenue adequate if the revenues collected from the economic dispatch in the form of
congestion payments are sufficient to fully fund payments for the FTRs. The general result is that under reasonable conditions, there is a straightforward test that ensures revenue adequacy. *If for the given grid configuration, the FTRs would be simultaneously feasible, then no matter what the pattern of actual loads and generation, economic dispatch*

This in turn could determine the CLMP, expressed as the difference in marginal congestion between a designated reference location and the specific bus of interest. In turn the difference in the CLMP between any two locations is the spot value of transmission between those locations (*i.e.*, the CLMP is an interval metric).

In a system where there are no binding transmission constraints, the CLMP would be zero. When the network was congested (*i.e.*, the cheapest resources could not supply all the power requirements), the CLMP at the source would be lower than the CLMP at the sink. Thus, load payments would exceed payments to generator. This difference, reflecting the CLMP impacts, is referred to as either the congestion rents or simply congestion. LMP thus also revealed a powerful pricing property beyond just the marginal cost signal to consume or produce, or the spot value of transmission (the difference in CLMP between nodes). *If a party possessed the right to receive the difference in CLMP between their desired source of power and their load location, they would be insulated or hedged from the impact of congestion (i.e., the charge from the actual congestion would be equal and opposite to the value of the related FTR).*

with locational prices would be revenue adequate. The underlying logic is that the economic dispatch is by definition feasible, and must be at least as valuable as any other feasible solution. In particular, the economic dispatch must be at least as valuable as the FTR implied feasible dispatch, valued at the locational prices. Hence, there must be enough economic surplus value to in effect buy out all the FTRs and reconfigure the pattern of flows according to the economic dispatch (Harvey et al., 1997). This revenue adequacy result stands in sharp contrast with the inherent problem of physical rights. The central problem of physical rights was that they could not be guaranteed. A "right" to move power between locations would always be limited by the fact that actual load and generation conditions in real time might preclude the exercise of the right. Hence, it was not possible to award physical rights that ensured that the holder would be able to move the power or capture the economic value. The fully funded FTR does guarantee that the holder will capture the economic value to hedge transactions that either actually move the power, as through a physical right, or provide the power through redispatch as part of the efficient economic solution. Hence, with the same grid and simultaneous feasibility of the FTRs, the efficient market design provides what is needed for competitive wholesale electricity markets. Even under these idealized conditions, the alternative vision of workable physical rights was a hopeless illusion. Physical rights would not work under the best of conditions. The solution is to provide and fund FTRs." Emphasis added. Citation to Harvey et al: Harvey, S. M., Hogan, W. W., & Pope, S. L. (1997). Transmission Capacity Reservations and Transmission Congestion Contracts. Center for Business and Government, Harvard University. Retrieved from http://www.hks.harvard.edu/fs/whogan/tccoptr3.pdf.

Further, Dr. Hogan proved that if such rights were awarded based on only the feasible power flows on the underlying transmission network, regardless of the actual feasible injections and withdrawals on that same transmission system, there would always be sufficient congestion rents to fund all of the awarded rights (Revenue Adequacy Theorem). This meant that the holder of the rights would receive their value in full on the given transmission system regardless of their own specific injections and withdrawals. This is fundamental to making the financial hedging function work and have the same financial result as holding firm transmission.

These rights, referred to as Financial Transmission Rights in PJM, thus created the now proverbial "financial equivalent of firm transmission". They fully covered all congestion costs between any source sink pair so long as the rights awarded were simultaneously feasible on the underlying transmission system as it existed in operation. These rights similarly resolved the limitations of the "old" contract path transmission paradigm. The FTRs would be valid under all configurations of system dispatch on the underlying network and automatically be utilized (funded) regardless of whether the holder chose to actually inject and withdraw power or not.

Seen in this context, and the above discussion regarding the sequence of Commission orders related to ISOs and RTOs, it should now become obvious why the FTRs played such an important role and are such a fundamental building block in achieving the Commission's objectives with respect to open access, and pricing while maintaining the ability of market participants to fully hedge.

As usual, however, the devil is in the details. Questions like "who gets what rights" or "how are the rights and associated fund are distributed/bought or sold" or "what happens if the underlying transmission system is derated and there is not sufficient congestion to fund all rights" and many other issues remained and still remain in each RTO implementation. Answering these questions with adjustments in specific rules, became the work tasks confronting each RTO (and they all have some variants of FTRs), as they pursued their individual implementation of FTRs and the ownership and disposition of the related congestion rents.

VI. PJM HISTORY: INITIAL MOTIVATIONS FOR FTR AND EVOLUTION TO ARR/FTR STRUCTURE

INITIAL FILINGS

Q. DESCRIBE YOUR PARTICIPATION IN THE INITIAL PJM AND STAKEHOLDER DISCUSSIONS ON MARKET DESIGN INCLUSIVE OF FTRs, AND THE EVOLUTION OF THE MARKET TO INCLUDE ARRs AS WELL.

A. I have been involved in PJM related ISO/RTO activities and stakeholder related meetings since PJM's first filings at the Commission in the period from 1995-1997. My initial involvement was on behalf of Cogen Technologies and then later, in early 1997, U.S. Gen also began supporting this work. Over time, multiple different parties have asked me to participate and monitor the stakeholder process, and this has been uninterrupted since the start of the market.

There was a lot of "maneuvering" for stakeholder support at the time surrounding the initial filings. The vertically integrated investor-owned utilities were leading the process. The companies were split into two groups: PECO, supporting a single clearing price market design, and the Supporting Companies, representing seven other PJM members supporting an LMP based single settlement market.[29] PJM's initial filing in late 1995 (pre-Order 888) was rejected by the Commission, and a revised filing was made in December 1996 following the Commission's guidance related to Order 888. The revised filing was interim in nature, starting with the PECO-supported single clearing price market, while more details of the LMP/FTR market were developed. The Commission approved the revised filing in February of 1997 and the single clearing price market went into effect under the PECO design in April 1997.[30] In June 1997, the Supporting Companies filed a revised and comprehensive market design based on the LMP/FTR concepts.[31] PECO and others filed an alternative.[32] After Commission approval, the LMP/FTR market design submitted by the Supporting Companies was approved and went "live" in April 1998.[33]

Q. DID YOU ENGAGE IN DISCUSSIONS RELATED TO TRANSMISSION RIGHTS IN GENERAL AND FTRs WITH PJM OR THE SUPPORTING COMPANIES PRIOR TO AND AFTER THEIR FILINGS?

A. Yes. This was one of several priority areas for Cogen Technologies. Aside from owning several generation facilities in New Jersey, they also had expansion capability for additional transmission able to connect PJM and NYISO at a third facility located in Linden New Jersey.[34] Cogen Tech was interested in maintaining the merchantability of the

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[29] See *PJM Interconnection, et al.*, 81 FERC ¶ 61,257 (1997) for a summary. Supporting Companies consist of the following: Atlantic City Electric Company (Atlantic City Electric), Baltimore Gas and Electric Company (BG&E), Delmarva Power & Light Company (Delmarva), Pennsylvania Power & Light Company (PP&L), Potomac Electric Power Company (PEPCO), Public Service Electric and Gas Company (PSE&G), and GPU, Inc. (GPU) (GPU consists of Jersey Central Power & Light Company (JCP&L), Metropolitan Edison Company (Met Ed) and Pennsylvania Electric Company (Penelec). I usually refer to the seven Supporting Companies because I partition GPU into its three subsidiaries.

[30] *Id.* There were numerous problems with the single clearing price design, which I believe were part of the impetus for the Supporting Companies' filing in June, 1997.

[31] *Id.*, see Docket Nos. ER97-3189-000 and EC97-38-000.

[32] *Id.*, see Docket No. ER97-3273-000.

[33] *Id.*

[34] This capability, transferred several times via sales, ultimately became the VFT DC transmission line between PJM Linden and NYISO.

additional capability of their transmission cable under a competitive RTO design, and also the types of transmission rights (FTRs) that might be obtainable related to the cable and/or congestion rights linked to sources and sinks that might utilize the cable. U.S. Gen had more general interests and a more diverse set of business objectives.

As I mentioned, the split between PECO and the remaining Supporting Companies resulted in a lot of maneuvering for stakeholder support. All of the PJM companies were balancing their own interests, concerns related to state regulators, and of course the evolving FERC environment just before and after Order 888. This created an opportunity for stakeholders, particularly those with specific interests and technical knowledge, to interact with PJM staff, and in my case, also the Supporting Company representatives on a number of issues.[35] With PJM I had a number of discussions regarding transmission rights with Mr. Herling and Mr. Ott regarding both incremental rights and the FTR design (particularly allocation of rights). With the Supporting Companies I had a number of discussions with several parties, but in particular, with Mr. Andrew Williams of PEPCO, who was chairman/leader of the Supporting Company's coalition.

Q. WHAT INSIGHTS DID YOU GAIN FROM YOUR DISCUSSIONS REGARDING THE ROLE OF FTRs TO THE SUPPORTING COMPANIES IN PJM'S ORIGINAL DESIGN?

A. While Dr. Hogan and his writings educated me about the technical side of FTRs, Mr. Williams offered a much different and very important perspective, particularly with respect to the link between generation and transmission ownership, state regulatory concerns, and transmission rights.

[35] Because the Linden Cogen cable had the potential to link PJM and NYISO, I also was involved with parallel discussions with NYISO.

PJM had a history of cooperative investment in transmission and generation. For example, two approximately 1700 MW coal stations (Keystone and Conemaugh) in west central Pennsylvania were built and paid for by multiple PJM companies, including those remote from the facilities (e.g. PSE&G in New Jersey). Similarly, the PJM members had entered into cooperative arrangements to build new high voltage transmission to secure congestion free access to these jointly owned generation facilities, as well as support the overall security of the pool.[36] Payments under these arrangements (*e.g.*, the EHV) were partitioned between creating congestion free access to the jointly owned generation facilities, and the overall pool security and ability to reliably import and transfer power.

Mr. Williams explained to me the need for the benefits of these large investments in generation and transmission to be preserved, not just from the reasonable self-interests of the parties that had paid for the facilities, but also from the perspective of each company's state/local regulators. Hundreds of millions of dollars of investment had been rate based on the understanding that ratepayers would have direct access to the cheap coal power produced by these plants. There would be no state regulatory approval absent the ability to demonstrate to these regulators that the customers would maintain the benefits from that generation and transmission after the switch to an RTO. *FTRs and PJM's proposed allocation of these rights allowed the Supporting Companies to provide the assurances they needed to both their own management and state regulators that the status quo in this respect could/would be maintained. Congestion free power from these remote resources would be maintained if that made the most economic sense. The FTRs allocated to these companies would provide the necessary hedge to accomplish this. This was a basic*

[36] Extra High Voltage Transmission Agreement (EHV), Lower Delaware Valley Transmission System Agreement, and Susquehanna-Eastern 500 kV Transmission System Agreement.

element of the design, and it comported with all of the FERC direction, including Order 888 and later decisions, even though it preceded them. It was a great insight into both the technical elements needed of any design as well as the regulatory/political realities.

This was a key observation to my clients and to me. The mathematical elegance of the LMP/FTR design in providing the financial equivalent of firm transmission on top of a network power flow was interesting, but *the practical strength of directly being able to tie congestion hedges to historic investments via the FTR construct assured senior management, investors, and local regulators that the design would not deny them the benefit of historic expenditures that were already captured in rate base.*[37]

THE MOVEMENT TO ARRs

Q. WHAT DO YOU CONSIDER TO BE THE NEXT MAJOR CHANGE IN THE PJM ARR/FTR MARKET DESIGN RELEVANT TO THIS FILING?

A. The addition of the ARR allocation process and associated annual auction. The LEI report provides a reasonably detailed description of the major changes in the FTR market (e.g. see Figure 15, page 40 and Appendices B and C discussions and Figures 54 and 55). In general I think this was a very good summary and captures most of the elements of the market changes. However, I think this discussion failed to recognize the dynamics of change from the initial market design to that proposed with ARRs in 2003, and in turn the report missed a major element of how fundamental that change was and the huge improvement it brought to the market.

[37] This was a valuable lesson. Later on, I was asked speak to state regulators in Virginia regarding the pending entry of Virginia Power into PJM. They expressed exactly the same types of concerns that I had discussed with Mr. Williams, and the explanation of how FTRs could be used to hedge historic supply (assuming that was deemed desirable) was of great interest to them.

Q. WHAT WAS THE IMPORTANCE OF THE MOVEMENT OF THE ORIGINAL ALLOCATION OF FTRs TO THE INTRODUCTION OF ARRs?

A. In PJM's original proposal, the FTRs were allocated in a fashion to preserve congestion free hedges between historic points of injection and withdrawal as discussed above. But a feature of this allocation was the requirement for the recipient of the FTR to have an ownership interest in the generation source. Even when moving to a major improvement (the addition of monthly auctions in 1999), this initial allocation feature requiring ownership in the source remained. Similarly the movement to a two-settlement market and the appropriate parallel shift of the FTR product to be based on day ahead settlements did not alter this feature.[38]

If you think about the timing of the first filing (November 1995), it becomes clear that development of the proposal occurred earlier, and that this was also a time when many of the PJM member companies were in the middle of their own deliberations regarding divestiture or spin-off of their generation assets and the beginning of retail access. In the time frame from the start of the process of establishing an ISO, to filing, and ultimately to approval, they would likely have maintained the mindset of a vertically integrated utility. Thinking this way makes the ownership requirement in the source generation condition for the FTR allocation reasonable. It assures those who paid for the capacity resource that other parties cannot oversubscribe their priority claim to FTRs sourcing at the generator. This again works to assure the hedge of congestion free supply from the generation to the beneficiary load, the key business and regulatory ingredient in achieving approvals.

[38] Note that until 2017, FTR funding was also improperly adjusted by real time balancing congestion. The Commission properly determined that this was inappropriate, and removed those credits and charges from the FTR settlement, properly recognizing the day-ahead nature of the product. 158 FERC ¶ 61,093 (2017).

Q. WERE THOSE ASSUMPTIONS REGARDING RESOURCE OWNERSHIP STILL VALID WHEN PJM'S INITIAL DESIGN WAS FINALLY APPROVED?

A. No. By the time of implementation of the LMP/FTR market, these vertically integrated based assumptions were no longer valid. At that point a number of the member companies had already divested or spun off their generation assets. With the ownership of the generation now partitioned from the "beneficiary" load, the PJM allocation of FTRs tied to generation ownership no longer made sense, particularly where the generation assets were spun-off to an affiliated entity. Essentially a portion of the transmission system that was still being paid for by load was being given as entitlement to the departed generation. To my knowledge, that was never accounted for in the divestiture/spin-off discussions or accounting.

To some participants like myself, this became very clear as some of the affiliate companies, now owning the eligible sources, began selling interests in the sources that would enable others to obtain FTRs with that source. The entitlement to the FTRs themselves, plus this ability to market portions of the entitlement was an unanticipated source of what appeared to be a material amount of funds. I personally thought this was inappropriate and contrary to the original intent I discussed above. I complained to both PJM, the member companies, and also spoke about this problem in the stakeholder process. Eventually this concern got traction from PJM and at least one of the benefiting companies. I participated in negotiations with PJM (Mr. Ott) and Mr. Sorenson of PSE&G's operating subsidiary (now PS-ERT) on the idea of a transition over several years away from this skewed allocation system to something more equitable. I raised the notion of Auction

Revenue Rights, a concept that had come up in my work with others outside of PJM[39] as a way to facilitate the transition: i) remove the requirement for ownership in the source generation, ii) transfer the preference for certain historic source-sink paths to the aggregated beneficiary load in the sink zone via the award of the ARR, and iii) institute a one year auction that would allow the explicit valuation of the ARRs based on expectations at the time and in turn the efficient reallocation of the FTR property right. Coupled with a broad auction of all rights, this process would not only effectively give the impacted loads the priority for the hedge from historic (but now unaffiliated generation), but also give them the option to release that right into the FTR auction for compensation that could be used to purchase other source-sink path FTRs if they so desired. These elements essentially became the cornerstone concept of the 2003 changes to the basic ARR/FTR construct that PJM still maintains.

Q. WHAT CONCLUSION DO YOU DRAW FROM THIS EXPERIENCE AND THE ASSOCIATED CHANGE?

A. *The key take-away should be that the transition was essentially back to the original objective of giving load a congestion free hedge to potential sources of dedicated generation, in this case their historic supplier locations*. It remediated a bias created due to the parallel development of retail access and the divestiture of generation. But it also had other benefits. With the addition of ability to either self-schedule (convert the ARR to an FTR in the auction) or release or sell the ARR at a reservation price (i.e. bid for the path in the auction at the reservation price and effectively pay themselves if they set the clearing price or release the right for a higher price), the load beneficiary now had more flexibility

[39] In particular Dr. Susan Pope who was already developing this type of ARR concept in NYISO and California.

to hedge consistent with the broad retail access designs of much of the market. For entities without retail access, there would basically be no change, except now they would also have greater flexibility in adjusting their FTR positions via the annual auction.

Q. DOES PJM AGREE WITH THIS OBSERVATION?

A. Yes. While PJM did not discuss the historic context in the manner I explain above, PJM in its White Paper summarized this result. However, I think the change and the importance of hedging becomes more compelling when understood in the context of why the initial change in 2003 occurred, and emphasizes the benefits we see at a high level in the current market structure:

> The current ARR/FTR construct provides additional advantages that did not exist in the former FTR-only construct. For example, the current PJM ARR construct provides both the opportunity to hedge based on historical physical contracts, as well as an option to hedge updated physical contracts or expected congestion. This is because of the option of converting the ARRs into FTRs, keeping the ARR credits only, or reconfiguring the ARRs to different FTR paths. This choice is important to load, because it provides load the flexibility to either collect the congestion revenues as it existed prior to the ARR construct, or to collect auction revenues, which are valued solely on the expected value of congestion as determined by the FTR bidders. These options provided to LSEs under the current ARR/FTR construct are not available if congestion revenues are broadly allocated, or if the ARR product did not exist. In addition, the ARR construct preserves the historical rights to load while providing flexibility to acquire the right to congestion revenues on alternative paths. The first rights to the congestion revenues on the historical transmission system are an important component for load in the PJM market, because these rights may correspond to physical transmission rights that predominantly existed before the creation of the LMP market.[40]

Q. WHAT OTHER NOTABLE CHANGES HAS PJM MADE THAT IMPROVED THE ARR/FTR PROCESS?

A. While I again note that LEI has prepared an excellent summary, besides the above point, I think that two of the changes LEI noted rise above the others in their importance to the

[40] PJM White Paper at 6.

improvement in the ARR/FTR construct achieving the intended objective of providing a financial equivalent to firm transmission, and implicitly doing so via the return of congestion rents to load via the FTR mechanism. These two events were: i) the exclusion of the improper allocation of balancing congestion charges to FTR holders, which removed inappropriate charges to FTR holders as well as a material amount of noise from the ability to properly valuate FTRs, and ii) the change in allocation of surpluses[41] from FTR holders to ARR holders. The allocation change of surplus was another move to aligning the benefits of the transmission system with those who pay for the system (load in general, holders of point-to-point transmission, and incremental transmission rights holders). With improved allocations of ARRs, I believe the addition of surplus to credit the allocations to ARR holders helps to "close the box" on the issue of returning congestion rents to load. While there will always remain some issues or noise in this process, this was (in my opinion) the logical missing link in that process. It is directly complemented by PJM's proposals to enhance the ARR process. Below I present a refinement that I believe furthers the effectiveness of this type of change.

VII. <u>LONDON ECONOMICS INTERNATIONAL REPORT</u>

OVERVIEW

[41] *See* LEI Report at 127. On June 1, 2018, FERC accepted PJM's request to shift payment of surplus congestion from FTR holders to ARR holders. Starting with the 2018/2019 planning period, surplus congestion has been paid out to load on a pro-rata basis to their positive ARR target allocations. PJM requested this change to align the FTR and ARR mechanisms with Purpose #1. Surplus congestion occurs only because the network model used by PJM to allocate ARRs and to clear FTRs in the annual and monthly FTR auctions is under-forecasting the extent of network capacity that is available in the day-ahead energy market. So, the existence of surplus congestion can be traced to a problem of ARR under-allocation. Therefore, it is reasonable that load should be the recipient of this surplus congestion (references omitted to 163 F.E.R.C. ¶ 61,165 (2018)). This is a significant change in the amount of congestion charges now received by load. From 2014/15 to 2019/20, the annual surplus congestion averaged $89 million, ranging from the low end of $23 million to a high end of $142 million. In the 2018/19 and 2019/20 planning periods, when surplus congestion changes were implemented, these funds represented 18%, and 21% of the total congestion charges returned to load.

Q. ARE YOU FAMILIAR WITH THE LEI REPORT?

A. Yes. I participated in the various stakeholder discussions related to the LEI task and report. (For the purposes of this proceeding I only refer to the revised report submitted on January 22, 2021.)

Q. DID YOU SPEAK WITH LEI DURING THEIR PREPARATION OF THE REPORT?

A. Yes. I don't believe I fell into what they describe as their formal interviews but several times I spoke with LEI staff regarding both my experiences with PJM's ARR/FTR market, and several ideas I had for modifications that I believe would complement the direction of their recommendations.

Q. WHAT WAS THE SCOPE OF THE LEI REPORT?

A. LEI conducted an orderly and thorough review of the PJM ARR/FTR process. They established two purposes that they concluded were the function of the ARR/FTR construct objectives they thought were appropriate and criteria to evaluate how well PJM was addressing those purposes. They also made general recommendations for future change. As part of the process they also provided summaries of the history and the ARR/FTR processes. The general purposes they identified were:

> Purpose #1: Facilitate the return of overpayment in locational marginal prices ("LMP")(known as congestion charges) back to load; and

> Purpose #2: Enable hedging of the marginal cost of congestion in LMPs between different nodes and support forward market activity through the offering of FTRs.[42]

Q. WHAT WERE LEI'S MAJOR FINDINGS?

[42] LEI Report at 3.

A. LEI concluded that the current ARR/FTR mechanism changes that PJM has put in place over time have improved the processes, with respect to these two basic purposes, and provided very material benefits to market participants.[43] As I mentioned earlier, they placed a partial estimate of the benefits of the ARR/FTR market structure potentially as high as $1.2 billion annually. They also found that stakeholders were generally satisfied with the current design, but noted some concerns regarding the ARR allocation process, as well as concerns related to designating priority ARRs for hedging as well as the complexity of the PJM modeling and simultaneous feasibility testing.[44] Most telling to me was their finding that most stakeholders preferred seeking incremental improvements and enhancements, particularly to the ARR allocation scheme, increased granularity of the FTR product and ability to place reservations charges (this already exists and apparently many stakeholders were not aware of how they could do this, i.e. simply bidding their reservation price into the FTR auction).[45] They also emphasized their conclusion that they believe that the major limitation or concern in the current market design is the allocation of congestion rents among LSEs.[46]

As can be seen, in general, LEI's findings were very supportive of the market. LEI Key Findings (page 19):

- A path-based construct, established out of recognition of the importance of bilateral and self-supply arrangements, continues to be relevant in the present day. The majority of load continues to be served through bilaterals (and self-supply).
- A dual system of property rights (ARR/FTR) creates value for load. The existing ARR construct gives load a choice to hold on to an ARR (and securitize

[43] *Id.* at 7.
[44] *Id.* at 9.
[45] *Id.* at 9.
[46] *Id.* at 17. It also should be noted that this is not just a distribution to LSEs but to firm point to point transmission customers and any party that has invested in transmission resources that have created incremental FTRs.

congestion charges in advance of settlement) or to self-schedule an ARR (and get a "perfect hedge" for congestion on a specific path that the LSE has committed resources and load).

- FTR auctions are working properly and should be retained. They are effective in achieving Purpose #1 (under normal weather conditions) and supportive of Purpose #2. Although there has historically been some "leakage" of congestion charges to non-load entities, due to participation of non-load entities in the FTR auction, these entities have positively contributed to the efficiency of the FTR auctions, and therefore enhanced the efficacy of the ARR/FTR mechanism while also allowing for price discovery in support of the forward markets.

- Liquid and efficient forward markets bring about a number of benefits for load. Illustrative examples suggest that the long run benefits for load are higher than the cost incurred by load (e.g., the "leakage" in congestion charges to non-load entities through FTR net profits). The current ARR/FTR mechanism, when evaluated against both Purpose #1 and Purpose #2, is creating overall positive value for load.

Q. DO YOU AGREE WITH THESE FINDINGS?

A. Yes. I think the overall analyses points out the constructive evolution of the market and the benefits it brings in its current form to market participants. Indeed their findings are the basis for the specific changes PJM has filed in this proceeding.

Q. WHAT EXCEPTIONS/DIFFERENCES DO YOU HAVE WITH THEIR FINDINGS?

A. There are two main areas where I thought that the LEI comments were a bit skewed or misleading. In the overall scheme it doesn't change their conclusions, but I am concerned that these two elements may be misrepresented or misconstrued by parties opposing the PJM filing.

The first has to do with the manner in which the two purposes (cited above) were represented. There really is just a single primary purpose, which was to create the financial equivalent of firm transmission to facilitate hedging, liquidity, and complement the bilateral markets. Inherent in this was the need to be able to fund the congestion between any source and sink pair desired for such equivalent of firm transmission. The source of those funds is the congestion rents (the amounts of payments by load in excess of payments to generators). Thus ,when the "package" of functions of the ARR/FTR market is considered, you cannot achieve the hedging function without returning the congestion rents to those who paid for the transmission system. Indeed, the pool of congestion rents reflects exactly the maximum amount that would be needed to fund any feasible set of transmission rights awarded (assuming a constant transmission topology). So inherent in LEI Purpose #2 is the return of congestion rents to load (Purpose #1).

I grant that there are better and worse ways to executing these arrangements, and I think the criticisms and suggestions of LEI are constructive. In particular, some of the recommendations of LEI regarding ARR allocations would further that goal. Again, these are included in PJM's proposed filing. But in the abstract, when the system would be fully utilized or consumed by awarded rights (directly through ARRs or via the allocation of surplus), the first function of returning congestion rents to load is fully addressed. [47] So there should be not debate about a priority or divisible function of just returning congestion to load (as purported by the IMM and discussed later), but rather about the efficiency in doing what is inherent in awarding FTRs that are the financial equivalent of firm transmission. As I said before, the devil is in the details, and I believe that PJM continues to improve in the primary (and effectively sole function) of making such rights in the form

[47] A simplistic way of seeing this is that at the time of the FTR auction, the auction revenues reflect to full market value of these rights. In turn, that value goes to ARR holders (directly or via self-scheduling) and if the process stopped right there, the rest of the value of the rights would be returned to LSEs as surplus. This obviously is an over simplification as the details of the change in market topology can modify the relative daily over and under funding, but notionally, this system is complete as presented.

of FTRs available while improving the equity and efficacy of returning the value of these rights to the appropriate people.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE THAT MAKES THIS OBSERVATION CLEARER?

A. Assume for the moment there were no ARRs and that an FTR auction was held for the entire system capability, and a "pile of money" that derives from the auction is the result. Assume also there are no market failures (e.g. no market power, sufficient participants to support a competitive results, and low barriers to entry). In this case, at that time, the revenues of the auction match 100% of the expected value of the set of simultaneously feasible rights that are available. No one, that I am aware of, debates the generic conclusion that the intent of the market design is to effectively put LSEs, point to point customers, and those that have expanded the transmission system, into a room with that "pile of money" and somehow partition it. All that PJM has done to date, based on the current ARR rules, is: i) partition some of those funds to this same group of transmission customers based on its stage 1, 1a and 2 ARR allocations and ii) partition the remainder based on auction surplus and related allocation rules.[48] *There is no leakage*, and there is no issue about achievement of the return of congestion rents to transmission customers.

This is distinctly different from the analogy that I have heard people use regarding equating congestion rents to the marginal lose surplus (MLS). It is indeed true that there is

[48] If one wished the example could be expanded. Consider the situation when prior to the auction, all the ultimate winning bids were somehow known, and given to LSEs in the form of the final auction FTR results. The auction revenue would remain unchanged, and now instead of going into a room and arguing over who gets what money, it is fully allocated by the ARRs. Next consider the same set of ARRs are created but now each is put on a piece of paper and they are randomly drawn from a jar by the various LSEs. Again the auction revenues are unchanged, but now the allocation of the pile of money has changed. In all these cases (again reflecting on the Coase Theorem the auction revenues will continue to be the same, with the rights ending up in the hands of the same parties (LSE or third party) based on their relative valuation of the rights, willingness to pay, and the underlying network and SFT constraint.

no "right" party to receive the MLS[49]. There are only equitable choices. *However, the same is not true on an aggregate basis with respect to congestion rents and the ability to achieve the financial equivalent firm transmission over any set of simultaneously feasible paths within a network.* There may be multiple equitable ways to partition who gets the rights and thus their share of the pile of money but there is no excess of funds as in the context of the MLS.

The second area where I have a different perspective is with respect to the notion of leakage. As cited above, LEI states: "Although there has historically been some "leakage" of congestion charges to non-load entities, due to participation of non-load entities in the FTR auction, these entities have positively contributed to the efficiency of the FTR auctions, and therefore enhanced the efficacy of the ARR/FTR mechanism while also allowing for price discovery in support of the forward markets.[50] While I agree with the statement, the term leakage has become derogatory in the sense that people assume that means that funds that should have gone to users of the transmission system is somehow inappropriately being diverted. Further, I think some of the discussion was misleading in that they also used the term leakage inferring that third party holders might somehow be profiting in a biased or inequitable manner (an inference that later LEI did clarify, and noted had no support).

This type of inference is simply incorrect. The only way third parties can receive FTRs is to pay for them, and pay at a market price. They can do so in the auctions (or

[49] In fact I have always argued that the MLS should first be applied to PJM overhead and then the rest given away. This is roughly consistent with the Ramsey pricing paradigm of dealing with true surplus or deficit of marginal costs versus average costs being assigned to the most inelastic participants (e.g. PJM overhead and parties not in the market). See Frank Ramsey, *A Contribution to the Theory of Taxation*, Econ. J. (1927).

[50] LEI Report at 19.

bilaterally), where they compete with other third parties, but much more importantly for this discussion, they also compete with load serving entities that may or may not have ARRs.

Any FTRs they receive in this manner is not leakage. This is a willing seller being happier with a fixed payment from a third party (and LSE or anyone else) in exchange for its ARR position (that can then be converted to an FTR), or when an LSE is facing a competitor for the right of interest and being outbid for it. If 100% of the system were consumed by allocations of ARRs, I would be shocked if the result of the auction results didn't reflect material holdings by third parties. Simple difference in risk profiles would justify fixed for variable swaps of some of the ARR positions held by LSEs in exchange for cash, instead of the receipt or holding of the associated FTR. LSEs continually engage in such exchanges to manage their risk, and multiple parties voiced their continued interest in keeping this ability under any future changes in the market.

Further, two incorrect notions that often are raised in discussions trying to "explain" leakages are that leakage occurs because there is no willing seller (*e.g.* there is system capability not consumed directly by an ARR allocation), nor is there the ability to set a reservation price.

These statements are also incorrect. Any market participant can set a reservation price for its ARRs by simply entering that price into the FTR auction. If it clears, they retain the ARR at a price (they effectively pay to themselves) that is equal to the reservation price. Alternatively, if the path is sold, it can only be sold above the reservation bid of the ARR holder. So indeed, there is a reservation function in the current market structure, but apparently some participants that are unaware of how to implement it. This is an education problem, not one of market design. What PJM is doing in this filing is facilitating what already can be done. There is nothing wrong with this, but the underlying claim of a flaw is incorrect.

Similarly, there are no unwilling sellers in the context that system capability not assigned via ARR is just "given away" at any price. Anyone can compete in the auction for any eligible FTR source sink pair. If something is sold "too low", that is because market participants did not express their valuation via a bid for that source-sink pair. If someone (an LSE or third party) feels the price is too low, they should be willing to offer (and should have bid) what they think it is worth. Competition yields a price representative of willingness to sell. Again there are minimal barriers to entry, and absent market power, this should not be a concern. Further, enhancements to putting more (if not all) of the system capability into ARRs would minimize this issue . This type of improvement is in PJM's proposal and I provide a possible further improvement below.

Similarly, to the extent that the ARR allocation didn't exactly match the desires of the holder (another criticism), they can and should liquidate some of their ARR holdings in exchange for funds to support purchases of FTRs with a different source-sink combination that is more desirable. That exchange may involve a third party, but it is always to the mutual benefit of both parties. None of this is leakage. It is exactly the type of Coasian adjustment/trading that one would expect in a low friction exchange market.[51] The FTRs will always wind up with the "right" parties based on willingness to pay, and the auction revenues will be partitioned as provided for by PJM's current rules plus

[51] *See* Coase, R., 1960. The Problem of Social Cost. The Journal of Law and Economics, 3, pp. 1-44.

enhancements. Further, what PJM is proposing should also increase the ability of the initial allocation to address such concerns.

In fairness, I would note that LEI does temper its characterization of leakage in a manner that incorporates much of what I am clarifying here. However, it is very important that this full understanding of the continuing misrepresentation of leakage is present, particularly, as I anticipate, a number of parties will be citing the report with an overlay of their own interpretations of what leakage means, inclusive of the IMM. LEI does clarify this similar to my above comments:

> It is important to acknowledge that there is a natural tension between equity and efficiency. Theoretically, a Pareto-efficient outcome (i.e., a situation where it is impossible to make someone better off without making someone else worse off) can be deemed inequitable in its division of social welfare (there may be winners and losers, and there is no guarantee that every market player is allocated the same amount of "social welfare"). Changing the distribution of social welfare (i.e., moving around the rent transfers) may require reallocation (or willingly incurring some "leakage" as part of the redistribution process).
>
> The two original purposes for the creation of FTRs are examples of a situation involving an equity-efficiency tradeoff. Some market participants raised concerns that there are "leakages" of congestion charges in the existing FTR auction design. This then impacts the congestion charges collected by PJM and returned to load (Purpose #1). From an equity perspective, this can be a concern. *However, if we take a holistic approach and consider the long-term efficiency in assessing the FTR design, these "leakages" are not strictly an economic loss but rather are viewed as costs for supporting hedging opportunities in the forward market, as discussed in Section 6.*[52]

VIII. PJM'S FILING AND PROPOSED CHANGES

Q. HAVE YOU REVIEWED THE PJM FILING?

A. Yes.

Q. CAN YOU SUMMARIZE PJM'S PROPOSED CHANGES?

[52] LEI Report at 48 (emphasis added) (footnotes omitted).

A. In general, PJM followed the major recommendations of the LEI report, as finally represented in the stakeholder process by a compromise proposal put together by a group of stakeholders.[53]

Q. WHAT ARE THE SPECIFIC LEI RECOMMENDATIONS THAT PJM CITED?

A. As relevant to this filing, the LEI Report made the following recommendations for modifications to enhance PJM's ARR/FTR market construct:

- expanding the sources and sinks available to load to nominate during the ARR allocation process to help direct congestion revenues to load;
- increasing up-front capability to load in order to protect zonal native load hedging ability and to help reduce excess congestion and auction revenue allocation equity concerns;
- exploring changes to the ARR process that would provide ARR holders more options and flexibility to self-schedule during FTR auctions;
- retaining the current set of FTR auctions and rules regarding participation and biddable points; and
- enhancing the FTR auction clearing rule to provide a minimum price floor as a prerequisite to clearing.[54]

Q. WHAT WERE THE PJM ARR/FTR ENHANCEMENT PROVISIONS THAT WERE PROPOSED IN THE FILING?

A. Reflecting the compromise stakeholder package, PJM filed six enhancement elements:

1. revising Operating Agreement, Schedule 1, section 7.4.2 and parallel section of Tariff, Attachment K-Appendix to expand the source/sink combinations permitted in the ARR allocation process to help prioritize directing congestion revenues to load and enhance alignment of ARRs to congestion paid through Congestion Locational Marginal Prices billing, and make related revisions to streamline the ARR allocation process while accommodating additional source/sink combinations ("ARR Source/Sink Expansion");
2. modifying Operating Agreement, Schedule 1, sections 5.2.2, 7.4.2, 7.5, and 7.6 and parallel provisions of Tariff, Attachment K-Appendix governing the creation of

[53] PJM Filing at 4-5.
[54] *Id.*

Stage 1 ARRs to replace the concept of "Zonal Base Load" with a standard of 60% of network service peak load in order to protect zonal native load hedging ability with additional up-front capability ("Stage 1 ARR 60% Load Standard");

3. revising Operating Agreement, Schedule 1, section 7.1.1 and parallel section of Tariff, Attachment K-Appendix to provide additional self-scheduling options ("Self-Scheduling Flexibility");

4. revising Operating Agreement, Schedule 1, section 7.8 and the parallel section of Tariff, Attachment K-Appendix to ensure source/sink combinations are limited to valid Stage 1 ARR paths for the customer funded Incremental ARR ("IARR') option in order to help ensure that that new IARRs, which can be administratively burdensome to administer, create value by enhancing market efficiency on valid, useful paths ("ARR Path Validity Requirement");

5. revising Operating Agreement, Schedule 1, sections 7.1.1, 7.1A.3, and 7.3.4 and parallel sections of Tariff, Attachment K-Appendix to create new FTR class types (and modify the existing types as needed) to provide for on-peak weekday, on-peak weekend and holiday, general everyday off-peak, and 24-hour products, which should increase hedging flexibility for all market participants ("Revised FTR Class Types");17 and

6. adding one sentence to the end of Operating Agreement, Schedule 1, section 7.3.6 and its parallel provision in Tariff, Attachment K-Appendix to create a floor for clearing prices for FTR options, specifically providing that FTR Options with a market-clearing price less than one dollar will not be awarded, which should help ensure that FTR options that are awarded add value to the market ("FTR Option Floor Price").

Q. DO YOU AGREE WITH THE PJM ENHANCEMENTS?

A. In general, yes. With respect to Enhancements 1 and 2, I believe my comments above are clear. In the abstract the status quo via the current ARRs and surplus allocation allocates the majority of the useful capability of the system and the associated auction revenues reflecting the market value to ARR holders. But similarly, I also believe that in general, pushing as much of this allocation into the ARR allocation process to represent the preferences of eligible ARR holders is desirable. Enhancements 1 and 2 continue to advance that objective.

Q. WHAT IS YOUR CONCLUSION WITH RESPECT TO ENHANCEMENT 3?

A. As I noted, the auction process is already amenable to self-scheduling and setting price reservations. The PJM proposal moves to simplify this. So again I would support this enhancement.

Q. WHAT IS YOUR CONCLUSION REGARDING ENHANCEMENT 4?

A. As I stated earlier, I do not have an opinion on Enhancement 4. The discussions during the stakeholder process and in PJM's filings are not persuasive to me that any modification is needed, especially retroactively.

Q. WHAT IS YOUR CONCLUSION REGARDING ENHANCEMENT 5?

A. I strongly support any increase in the granularity of the potential rights, and similarly the eligible nodes/busses for sources and sinks. Absent manipulation and/or market power, this can only enhance the efficiency and flexibility of the market. It is important that PJM maintain a consistent representation between such new product definitions and the ARR allocations. In turn, this argues for even more flexibility in the quantity and eligible source and sinks within the ARR process.

Q. WHAT CONCLUSIONS DID YOU REACH REGARDING ENHANCEMENT 6?

A. Overall I would say I am somewhat indifferent with respect to Enhancement 6, but see no material adverse impact of setting a floor price on options. As noted in the filing, options are only a small portion of the market and while such a limit is inconsistent with a market based indication of value, I don't believe it is a material matter. I would note that I believe that PJM Enhancements 1 and 2, would likely result in the great reduction if not elimination of such low price options occurring in the first place.[55]

[55] One way of visualizing the pricing of options is that they effectively must "buy out" any potential counter-flow that others might be offering into the market. Enhanced bid alternatives and granularity of nodes should drive the cost of this, and thus potential option clearing prices higher.

IX. IMM RECOMMENDATIONS

Q. HAVE YOU REVIEWED THE VARIOUS PRESENTATIONS AND PROPOSALS MADE BY THE IMM WITH RESPECT TO MODIFICATIONS FOR THE ARR/FTR PROCESS?

A. Yes. I have read most, if not all, of the IMM presentations/reports and attended most, if not all, of the stakeholder meetings where the presentations were made. I have also had several opportunities to discuss the IMM proposal "off-line". These occurred with Mr. Haas and Dr. Bowring.

Q. WAS THE IMM'S PROPOSAL'S CONCEPT SUPPORTED BY THE CONCLUSIONS IN THE LEI REPORT OR PJM'S WHITE PAPER?

A. No. Just the opposite. The IMM proposal works directly at cross purposes with the LEI and PJM findings. In actuality, while it does return day ahead and unrelated balancing congestion to LSEs, it does so in a manner that actually harms both the ability to hedge and to have reasonable open access transmission for parties willing to pay for firm transmission service. I will summarize the related LEI comments below as part of my discussion. The IMM proposal also did not receive significant support in stakeholder voting.[56]

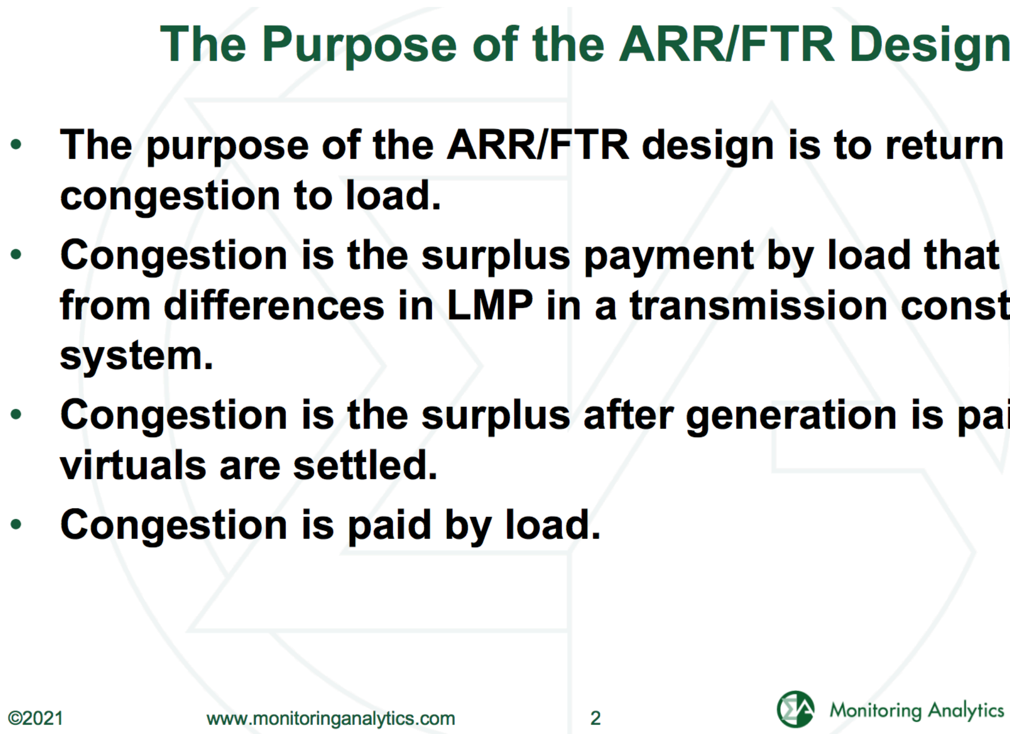
Q. WOULD YOU PUT YOUR COMMENTS REGARDING THE IMM'S PROPOSAL IN CONTEXT VIS A VIS OTHER SUBMISSIONS BY ETI?

A. I am providing here a high level summary of the IMM's proposal, particularly the elements that I believe are simply incorrect, or are problematic to the function of the market as a whole, or the ability for PJM to even maintain such a market under FERC jurisdiction.

[56] I do not intend to suggest stakeholder votes are dispositive of the analytic merit of a proposal. In this case, it is highly likely most market participants did not recognize the full nature of the status quo and even more likely did not understand the full implications of the IMM proposal. As I will explain briefly in this section, the proposal's material flaws and real threat to the function of the market are the basis for my opposition to this proposal.

Q. WHAT IS DESIGN OBJECTIVE/PURPOSE OF THE IMM'S PROPOSAL?

A. The clearest statement of purpose for the IMM's proposal was reflecting in a presentation made by Mr. Haas (IMM Chief Economist) at a June 25, 2021 meeting of the ARR FTR Task Force (ARMTF). The image below is the first substantive slide of the presentation[57]:



Q. DO YOU AGREE WITH THIS STATEMENT OF PURPOSE REGARDING THE ARR/FTR DESIGN?

A. No. This is a myopic and incomplete view, and as such creates a false premise for the IMM's overall proposal. As I discussed at length above, the FTR function grows out the use of a locational marginal pricing paradigm for energy and the coupled need to create the

[57] *See ARR/FTR Market Design and Design Components: IMM Proposals*, monitoringanalytics.com, (June 25, 2021), https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/2021/20210625/20210625-item-05-imm-market-design-notes-update.ashx. The IMM also presented a written summary of its approach as of July, 22, 2020, *see Constraint Based Congestion Calculations: Measuring Congestion Paid by Zone*, monitoringanalytics.com, (July 22, 2020), https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/2020/20200722/20200722-item-03a-constraint-based-congestion-calculations.ashx (IMM Paper).

financial equivalent of firm transmission in order to meet the open access to transmission objective of the Commission. In this context, congestion is indeed collected (payments by load in excess of payments to generators), but as repeatedly stated, the purpose of the distribution of the congestion was to facilitate/create the financial equivalent of firm transmission in the furtherance of the Commission's initiatives to support competition in wholesale markets via open access. Also as noted above, one of the special attributes of the congestion collected is that it can financially support (by paying all the congestion costs incurred between source and sink FTRs) all simultaneously feasible rights in the system. *It is this compensation to hold parties financially harmless from congestion for their desired transmission paths (so long as they are simultaneously feasible, i.e. consistent with the actual transfer capability of the system) that returns congestion to load.*[58] The Commission has been clear about this priority. The quote below reflects LEI's interpretation of the FERC guidance and similarly the distortion of purpose by the IMM:

> Currently, there are different views on the purposes of FTRs. For instance, the IMM believes that the ARR/FTR construct has only one purpose: to return exactly 100% of the congestion charges collected in LMPs back to load. Although FERC recognized that FTRs would facilitate the return of congestion charges to load, FERC never stated that load should receive exactly 100% of congestion charges collected in LMPs. Indeed, FERC described the conceptual basis for FTRs more broadly than simply the return of congestion charges in the original decisions, referring to the concept of hedging and discussing the PJM Companies' arguments regarding the need to accommodate bilateral contracts.[59] More recently, FERC clarified its understanding, noting that that FTRs were "designed to serve as the financial equivalent of firm transmission service and play a key role in ensuring open access to firm transmission service by providing a congestion-hedging function."[60]

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[58] And as also explained, to the extent that the rights are valued more by third parties, the rights and associated congestion will go to third parties, but only after purchasing such rights in a manner where this higher valuation flows to LSEs.
[59] LEI Report at 29.
[60] *PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,093 at P 11 (2017).

In PJM's White Paper, they quote even more direct and forceful language on this issue from the Commission:

> FERC has stated multiple times that the sole purpose of the FTR product is **not** to return 100 percent of congestion to load. An FTR market designed to achieve this goal could reduce the incentive for needed investments in generation resources and transmission upgrades. In January 2017, the Commission stated:
>
> > *"Finally, the Market Monitor and Joint State Commissions reiterate the proposal, as made in their earlier filings, that the Commission should support a market redesign to ensure loads receive all congestion revenues.* ***We reject the arguments that the sole purpose of FTRs is to return congestion revenue to load, and the market should therefore be redesigned to accomplish that directive****. FTRs were designed to serve as the financial equivalent of firm transmission service and play a key role in ensuring open access to firm transmission service by providing a congestion-hedging function. The purpose of FTRs to serve as a congestion hedge has been well established. In the Energy Policy Act of 2005, Congress added section 217(b)(4) to the FPA, directing the Commission to exercise its authority to "enable load serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs." In Order No. 681, the Commission clearly emphasized the significance of FTRs in hedging congestion price risk."*[61]

Q. HOW HAS THE IMM CHOSEN TO IMPLEMENT THIS FALSE PREDICATE?

A. The IMM's general approach, building from this false premise, is to attempt to isolate what it deems as the "true" congestion faced by any load in the day ahead and real time balancing markets, *and then, on an* ***ex post*** *basis, allocate these funds back to the load.* Note that the IMM methodology also includes charges and credits from the real time balancing market (a practice the Commission has previously soundly rejected.)[62]

As presented, the proposal has four main flaws. First, at the highest level view, this is just another way to allocate congestion to load, but in a manner totally devoid of any context to the basic Commission objectives regarding firm transmission. Second, by

[61] PJM White Paper at 14 (citing the Commission)(emphasis in PJM citation, not in original).
[62] *PJM Interconnection, L.L.C.*, 156 FERC ¶ 61,180 (2016).

making the settlement of the day ahead and real time balancing congestion ***ex post***, the proposal makes it impossible for loads to have any realistic expectation of being able to hedge their specific supply from a designated source. This occurs because the basic definition of where the congestion rents the load will receive come from is undefined in advance and only known after the fact. There is no way for these parties to either know their specific entitlement in advance and thus exchange it ex ante for a known congestion hedge supported by market results. **Indeed I believe that something as simple as obtaining firm (congestion free), point to point transmission service would not be possible under the IMM proposal.** Third, because of the ex post nature, the only feasible hedging would have to occur on a bilateral basis not supported by the PJM market, e.g. to hedge from source A to sink B, a party would have to find, external to the PJM markets platform, someone willing to take on the B-A risk. This isn't impossible, but it is an inefficient process not tied directly to the PJM market platform (i.e. anyone like ICE or Nodal Exchange could implement such trades). And fourth, the inclusion of balancing congestion is simply wrong, and reflects a collateral attack on strong findings and direction previously provided by the Commission, noting that there was no reasonable cost causation between the day ahead congestion and congestion rents for FTR holders and the sources of balancing congestion. Collectively, this effectively removes any third party participation from the market (or lack of market). I believe that, at least indirectly, this also was one of the IMM objectives.

Q. HAS PJM ATTEMPTED TO ESTIMATE THE VALUE OF EXTERNAL PARTICIPATION IN THE FTR MARKET IN TERMS OF OVERALL MARKET REVENUES?

A. Yes. In the PJM White Paper, PJM conducted a comparison of the benefits that external trade brings to the overall function of the annual auction in terms of absolute revenues and implicit in terms of liquidity and efficiency. PJM stated:

> In order to illustrate whether or not financial participants create competitive forces which can enhance market liquidity and contribute to price discovery, a hypothetical study removing the bids from purely financial traders and holding all other bids constant was performed to show the impact on ARR values for the 2018/2019 and 2019/2020 Planning Periods. Results show a devaluation of roughly $329 million in 2018/2019 and $150 million in 2019/2020 without financial participation.[63]

Annual Auction Studies Without Financial Participant Bids

Planning Period Study	**Baseline**		**No Financial Participants**	
	Participants	**ARR Value**	**Participants**	**ARR Value**
2018/2019	189	$784 M	79	$455 M
2019/2020	196	$811 M	71	$656 M

Q. WOULD THIS VALUE BE ELIMINATED BY THE IMM PROPOSAL?

A. Yes. Further, I believe that the LEI-estimated up to $1.2 billion annually in value contributed to the market from the ARR/FTR market would also disappear. Hedging within the PJM platform would be eliminated and liquidity would be drastically decreased if not eliminated. These benefits are what drive the LEI estimate and would become infeasible under the IMM proposal.

Q. PLEASE EXPAND UPON YOUR FIRST TWO CONCLUSIONS ABOVE REGARDING THE IMM PROPOSAL.

[63] PJM White Paper at 19-20.

A. As I explained earlier, the CLMP is an interval metric, the differences have meaning, not the absolute values or ratio of values. Everything is stated in terms of the marginal congestion difference from a reference bus, and then differences between the CLMP at each bus of interest. The IMM's approach simply calculates positive only differences in congestion by moving the reference bus to the most negative CLMP bus caused by each constraint. It does so for each constraint and then allocates total congestion based on these results based on after the fact results. This is done for both the day ahead and real time balancing congestion results.[64] While this is certainly one way to allocate congestion (excluding for the moment the inclusion of real time congestion and the ex post design), *it has no ability to be linked to the underlying historic investments in the construction of the system for physical hedges of supply or purchases of point to point service or FTRs for financial hedges*. Nor can it support any ex ante defined rights as the congestion elements supporting the allocation are unknown until after the fact.

For example, notionally, if a party built a 100 MW line expansion to receive 100 MW of congestion free power from a source on the "low" side of the upgrade to its load, *there is no assurance that as other load demand may increase congestion on the*

[64] See IMM Paper at 13.
Steps for Determining Sources of Day Ahead Congestion:
1. Collect CLMP by constraint by bus by hour.
2. Collect load by bus by hour.
3. Collect generation by bus by hour.
4. Collect day ahead transactions by bus by hour (WHLIN, WHLOUT, IMPORT, EXPORT, UTCs, INTERNAL).
5. Calculate day ahead congestion by constraint for each hour.
6. Move the reference bus to the location of the most negative CLMP caused by the studied constraint and update resulting CLMPs caused by the constraint studied.
7. By constraint, calculate downstream (+CLMP) congestion charges to load by bus by hour.
8. By constraint, calculate the proportion of downstream (+CLMP) congestion charges collected at each downstream bus by hour by physical load.
9. Congestion collected from a downstream load bus is each constraint's total congestion times the proportion of downstream (+CLMP) congestion charges collected at that bus by hour.

line/upgrade in question, that the original party investing in the upgrade would be allocated its priority share of the use of that line per its investment. Rather, under the IMM proposal, the investing party's entitlement would vary from day to day based on the relative use of other, changes in topology, and any other element that may change the distribution of congestion per the IMM methodology. In fact, there is no guarantee that it would any share of such congestion at all. Indeed, it could go to zero.

Further, the party's allocation would always be limited by its actual use, and not for the value it created (or paid for) on the system. Regardless of investment in the grid for new transmission capability and the purchase of transmission rights, the party has no claim beyond a ratio share based on actual use as determined ex post evaluation of actual day ahead and real time load, supply and transmission conditions.[65] *Again, this combination of impacts makes it impossible to hedge as the actual congestion shares collected and related implied sources and sinks are unknown in advance. This is a full retreat from both supporting bilateral markets, open access and the related flaw in contract path design that resulted in a "use it or lose it" structure*.

Q. CAN YOU EXPLAIN MORE ABOUT YOUR THIRD POINT REGARDING THE IMPLICATIONS OF EVERYTHING BEING EX POST UNDER THE IMM'S CALCULATION?

A. One of the advantages of *any* fixed ex ante allocation of transmission rights is that when coupled with an efficiently structured auction like PJM holds for FTRs, the rights will be "rearranged" in a manner that results in the best use of the transmission system (best being defined in terms of Pareto optimality where no one party can improve its position except

[65] This is a perverse form of the undesirable "use it or lose it" transmission right, as the entitlement is unknown and may go to zero.

to the detriment of another based on each party's demand and willingness to pay). This again is the Coase Theorem in action in a low friction environment. But for this to work, the parties have to know exactly what they have to buy/sell/trade among themselves. You simply can't do this with the ex post process the IMM is proposing. No position is known until after the fact.

Further, this also means that no rights can be sold on a network basis backed by the PJM network and the congestion incurred on that system. Under the IMM's proposal PJM could not commit to funding any rights out of congestion rents as PJM would not know who had what in terms of congestion allocations until after the fact. The only feasible trading system under this type of structure is bilateral and exogenous to the actual market, e.g. I can buy A-B congestion rights/obligations if and only if I can be matched with someone else who will sell B-A congestion rights/obligations. But neither party can directly relate or fund such a transaction via actual market congestion payments. E.g. Any two parties could engage in such a bilateral, and even use PJM pricing as a "mark", but neither would even have to be a participant in the market, and their participation would be independent of the bilateral trade or any market congestion funds they receive.

There are several material and adverse consequences here from being forced into a bilateral only trading structure (*e.g.*, think of the market design that ENRON kept pursuing as opposed to LMP). The first is that it is enormously inefficient. The entire network flexibility and ability to rearrange/reconfigure rights that are bought and sold in an optimal fashion over the network is lost. This is one of the reasons people like ENRON liked bilateral only trading. It created wide bid-asked spreads that worked to the benefit of larger traders with better information. The second adverse consequence is that besides inefficiency, it has nothing to do with PJM's system or operation. PJM could post a matching buy/sell bulletin board, but it has nothing to do with the operation of the market. I can do that too, and so could anyone else.

Q. WOULD YOU EXPAND ON YOUR FOURTH ITEM, THE INCLUSION OF BALANCING CONGESTION IN THE IMM'S PROPOSAL?

A. The IMM is proposing (once again) to include balancing congestion as part of its ex post payment settlement structure to the FTR market. The Commission has already strongly expressed its rejection of these types of charges being included in the FTR structure, correctly observing that such charges have nothing to do with the causality of payments based on the day ahead settlements. The same holds true here, but in spades. I have absolutely no idea what an ex post settlement like the IMM proposes means with respect to basic use and rights on the transmission system. It is simply a non-sequitur. But for completeness I have included excerpts of the previous Commission decision in this area that are even more on point in the context of the IMM proposal. [66]

> Finally, we agree with the position advocated by PJM at the technical conference that FTR underfunding can be reduced by excluding from the FTR settlement process the real-time cost of a congestion imbalance, i.e., a cost that is not related to day-ahead congestion. Accordingly, we find that the inclusion of balancing congestion in the definition of FTRs is unjust and unreasonable as it contributes to the identified unjust and unreasonable cost shift. We therefore require PJM to allocate balancing congestion to real-time load. To address the tariff changes ordered herein, we require PJM to submit a compliance filing within 60 days of the date of this order.[67]

> *For the reasons discussed below, we find that the inclusion of congestion imbalance costs (a real-time cost) in the definition of FTRs (and thus, by extension, in the day-ahead FTR settlement process), is unjust and unreasonable.* Accordingly, we require PJM, in its compliance filing, to remove the term balancing congestion from

[66] 156 FERC ¶ 61,180.
[67] *Id.* at 2.

its definition of an FTR and to allocate these costs, instead, to real-time load and exports.[68]

We find that the inclusion of balancing congestion in the settlement of FTRs is not just and reasonable as it contributes to the identified unjust and unreasonable cost shift between ARR holders and FTR holders, is inconsistent with cost causation principles, and reduces the efficacy of FTRs as a hedge. The value of an FTR is determined by day-ahead energy market prices that reflect day-ahead congestion costs. The FTR can serve as a hedge against day-ahead congestion. By contrast, balancing congestion, whether positive or negative, is a settlement based on costs incurred in the real-time market. As such, the inclusion of these real-time costs lowers the value of FTRs, thus limiting the efficacy of FTRs as a hedge against day-ahead congestion.[69]

95. Although balancing congestion is currently allocated to FTR holders, FTR holders do not cause and cannot predict the level of balancing congestion. In addition, FTR holders are not the sole beneficiaries of balancing congestion. As noted above, negative balancing congestion occurs when real-time transmission capacity is less than day-ahead transmission; it may occur due to congestion on PJM's borders, transmission outages, reductions in system capability, or loop flow. FTR holders, however, are not the cause of these occurrences. Nor do they alone benefit from the payment of balancing congestion. Thus, the current allocation of balancing congestion to FTR holders is not consistent with cost causation principles.[70]

Q. DOES THIS CONCLUDE YOUR AFFIDAVIT?

A. Yes.

[68] *Id.* at 30-31 (emphasis added).
[69] *Id.* at 31.
[70] *Id.* at 32.

Exhibit ETI-2

QUALIFICATIONS
AND
EXPERIENCE OF

DR. ROY J. SHANKER

EDUCATION:

Swarthmore College, Swarthmore, PA
A.B., Physics, 1970

Carnegie-Mellon University, Pittsburgh, PA
Graduate School of Industrial Administration
MSIA Industrial Administration, 1972
Ph.D., Industrial Administration, 1975

Doctoral research in the development of new non-parametric multivariate techniques for data analysis, with applications in business, marketing and finance.

EXPERIENCE:

1981 - Present	Independent Consultant P.O. Box 1480 Pebble Beach, CA 93953 Providing management and economic consulting services in natural resource-related industries, primarily electric and natural gas utilities.
1979-81	Hagler, Bailly & Company 2301 M Street, N.W. Washington, D.C. Principal and a founding partner of the firm; director of electric utility practice area. The firm conducted economic, financial, and technical management consulting analyses in the natural resource area.
1976-79	Resource Planning Associates, Inc. 1901 L Street, N.W. Washington, D.C.

Principal of the firm; management consultant on resource problems, director of the Washington, D.C. utility practice. Direct supervisor of approximately 20 people.

1973-76 Institute for Defense Analysis
Professional Staff
400 Army-Navy Drive
Arlington, VA

Member of 25 person doctoral level research staff conducting economic and operations research analyses of military and resource problems.

RELEVANT EXPERIENCE:

2021

261—On behalf of the PJM Power Producers Group (P3) before the Federal Energy Regulatory Commission Docket No. ER21-2582-000. Affidavit addressing PJM's proposed modification of the Minimum Offer Price Rule and problems related to the economic justification of the proposed narrowing of the applicability of the rule.

260—On behalf of LS Power Associates L.P. before the Federal Energy Regulatory Commission Docket No. ER21-2043. Affidavit discussing PJM's revised Effective Load Carrying Capability proposal, its limitations and associated PJM responses to previous comments regarding its initial proposal.

259—On behalf of Indicated Suppliers before the Federal Energy Regulatory Commission in Dockets No. EL19-47-000 and EL19-63-000 comments regarding the PJM proposed modification to its Market Seller Offer Cap in the Reliability Planning Model Base Residual Auction for Capacity Resources.

258—Written post conference comments in Federal Energy Commission Docket No. AD21-10. Discussion of the appropriate scope and range of actions for the Commission with respect to the PJM Minimun Offer Price Rate. Similar considerations of the legal scope of the Commission under the Federal Power Act.

257—Invited Speaker before the Federal Energy Energy Regulatory Commission Docket No. AD21-10. Comments before the Commissioners related to the role of subsidies and their impact in terms of the determination of satisfaction of just and reasonable rates under the Federal Power Act.

256—On behalf of LS Power Associates L.P. before the Federal Enegy Regulatory Commission Docket No. ER21-278-001. Affidavit discussing PJM's Effective Load Carrying Capability proposal, its limitations and associated PJM responses to the Commission's deficiency notice.

2020

256—On behalf of Cricket Valley Energy Center and Empire Generating Company before the Federal Energy Commission Docket EL21-7. Affidavit addressing the appropriate design of offer price floors in the NYISO Capacity market and associated mitigation and extension of the related rules to the entire state.

255—Invited speaker and written submission before the Federal Energy Regulatory Commission Docket AD20-14. Comments about the legal issues under the Federal Power Act relevant to the implementation of carbon pricing within the wholesale regional transmission organizations.

254—On behalf of Shell Energy North America before the Federal Energy Regulatory Commission, Docket EL20-49. Affidavit addressing bilateral trading of FTRs, associated agreements and the interaction with PJM's FTR Center reporting and Tariff.

2019

253—On behalf of White Oak Power Constructors before the United States District Court for the Eastern District of Virginia (Richmond Division). Expert report on proper calculation of damages and costs associated with the delay in commercial operations of a new electric power generation facility.

252—On behalf of the Public Service Companies before the Federal Energy Regulatory Commission, Docket ER19-1486. Affidavit regarding the PJM proposed operating reserve demand curve and other modifications to the reserve products market. Comments on missing elements within the proposal.

251—On behalf of Indicated Parties, (Calpine, Vestra, and Electric Power Supply Association) before the Federal Energy Regulatory Commission. Docket EL19-63. Affidavit regarding the complaint of the Joint Consumer Advocates regarding PJM's market seller offer cap, the potential exercise of market power in the capacity market and appropriate market design adjustments under the Capacity Performance paradigm.

250—On behalf of Indicated Parties, (Calpine, Vestra, and Electric Power Supply Association) before the Federal Energy Regulatory Commission. Docket EL19-47. Affidavit regarding the appropriate adjustment of penalties and the Market Seller Offer Cap within the PJM Capacity Performance paradigm.

249—Supreme Court of the United States. Brief of Energy Economists as Amici Curiae in Support Of Petitioners, Nos. 18-868 & 18-879. Discussion of the impact of subsidies in electric energy market structures and the relationship of the instant cases where a Writ of Certiorari is being sought to previous Supreme Court precedent regarding state actions that effect Federal Energy Regulatory Commission jurisdictional rates.

2018

248—On behalf of PJM Power Providers (P3). Federal Energy Regulatory Commission. Docket EL18-178. Affidavit addressing the appropriate mechanisms to address state/public policy subsidies in the PJM Reliability Planning Model capacity construct. Related comments with respect to a "Clean" Minimum Price Offer Rule.

247—On behalf of Calpine Corporation, Eastern Generating and CPV Power Holdings. Federal Energy Regulatory Commission. Docket No. EL18-169. Affidavit addressing the the establishment of a "clean" Minimum Offer Price Rule for capacity offers in the PJM markets.

246—On behalf of DC Energy LLC and Vitol Inc. Federal Energy Regulatory Commission. Docket No. ER18-1334. Affidavit on the CAISO proposals to limit source and sink pairs in its annual and monthly CRR auctions, as well as comments addressing appropriate coordination of transmission outage and constraint information.

245—On behalf of the PJM Power Providers. Federal Energy Regulatory Commission Docket No. ER18-1314-000. Affidavit on the PJM proposed mitigation alternatives for addressing out of market subsidies either by Repricing or a modified Minimum Offer Price Rule.

244—On behalf of Joint Commentors. Federal Energy Regulatory Commission Docket EL18-34. Participation in the preparation of comments addressing PJM's proposed fast start pricing modifications and related price formation issues.

243—On behalf of the PJM Power Providers Group. Federal Energy Regulatory Commission Dockets EL17-32 and EL17-36. Pre-Technical Conference Comments and participant technical conference regarding seasonal capacity products and specific related reliability and forecasting questions from Commission Staff.

2017

242—On behalf of the PSEG Companies. Federal Energy Regulatory Commission Docket No. ER13-535-000. Affidavit regarding implementation of Court of Appeals remand to FERC of the PJM capacity market Minimum Offer Price Rule.

241-- In the United States Court of Appeals for the Second Circuit. Case No. 17-2654.Co-writer/sponsor of the Brief of Energy Economists as Amici Curiae in Support of Plaintiffs-Appealants-Reversal. Comments regarding the impacts of subsidies on the operation of organized electric markets.

240—In the United States Court of Appeals for the Seventh Circuit. No. 17-2433.Co-writer/sponsor of the Brief of Energy Economists as Amici Curiae in Support of Plaintiffs-Appealants. Comments regarding the impacts of subsidies on the operation of organized electric markets.

239—Invited speaker Federal Energy Regulatory Commission technical session, Docket AD17-11. Comments on the appropriate incorporation of state policies in wholesale electric markets. Submission of post technical session comments.

238—On behalf of PJM Power Providers. Federal Energy Regulatory Commission Dockets EL17-36 and EL17-32 addressing the current Capacity Performance design and criticisms related to the exclusion of an inferior seasonal capacity product. Explanation of how PJM establishes its adequacy targets and whether or not the asserted criticisms were valid.

2016

237- On behalf of DC Energy, Vitol, Intertia Power, Saracen Energy East. Federal Energy Regulatory Commission Dockets EL16-6, ER16-121. Submission of post technical session statement regarding PJM FTR market “netting” proposal.

236-On behalf of DC Energy, Vitol, Intertia Power, Saracen Energy East. Federal Energy Regulatory Commission Dockets EL16-6, ER16-121. Participant in two Technical Session Panels addressing PJM FTR market design and deficiency in the pending proposal to remove netting in the market settlement.

2015

235- On behalf of the Electric Power Supply Associaton. Federal Energy Regulatory Commission Dockets EL15-70, 71, 72, 82. Affidavit regarding MISO capacity market design and also addressing use of opportunity costs in offers.

234-On behalf of the Electric Power Supply Associaton. Federal Energy Regulatory Commission Dockets EL15-70, 71, 72, 82. Discussant in technical session addressing the establishment of opportunity costs as the basis for capacity reference pricing in the MISO Planning Resource Auctions.

233-On behalf of Dominion Virginia Power. Federal Energy Regulatory Commission Docket ER15-1966. Affidavit regarding changing economic incentives for suppliers associated with the modification of PJM's calculation of Lost Opportunity Costs.

232-On behalf of "Indicated Suppliers" Federal Energy Regulatory Commission Docket No. EL15-64-000. Testimony addressing the appropriateness of proposed changes to the NYISO buyer side mitigation exemptions.

231-On behalf of Hydro Quebec, Energy Services U.S. Federal Energy Regulatory Commission Docket No. ER15-623. Affidavit addressing the consistent treatment of energy imports under PJM's Capacity Performance proposal.

230-Before the Supreme Court of the United States, No. 14-995, On Petition for a Writ of Certiorari to the United States Court of Appeals for the Third Circuit. Brief of electrical engineers, scientists and economists as amici curiae in support of petitioners. Metropolitan Edison et al. versus Pennsylvania Public Utility Commission et al., http://www.americanbar.org/content/dam/aba/publications/supreme_court_preview/briefs_2015_2016/14-840_Borlick_et_al.pdf.

2014

229-On behalf of Benton County Wind Farm. United States District Court Southern District of Indiana, Indianapolis Division, Civil Action No. 1:13-cv-1984-SEB-TAB. Expert Reports addressing custom and practice in electric power purchase agreements.

228-On behalf of FirstEnergy Services. FERC Docket EL14-55. Affidavit related to the appropriate characterization of Demand Response in

Capacity Markets reflecting performance as the reduction of retail energy consumption.

227-Federal Energy Regulatory Commission. Docket RM10-17. On my own behalf, a statement regarding the ability of the PJM capacity and energy markets to clear in the transition from any determination that demand response would be excluded jurisdictionally from wholesale markets. This could in turn result in a more appropriate representation of retail demand response.

226-Illinois Commerce Commission. Matter: No. 13-0657. On behalf of Commonwealth Edison Company. Testimony regarding the operation of the PJM regional transmission expansion planning process in general and particularly with regards to the preservation of long-term transmission rights (Stage 1A Auction Revenue Rights), and the consequences that occur when such mandated rights are infeasible.

225-Federal Energy Regulatory Commission. Docket ER14-1579. On behalf of H-P Energy. Affidavit explaining importance of property rights and associated contracts within the PJM transmission planning process, particularly as they pertain to Upgrade Construction Service Agreements.

2013

224-Federal Energy Regulatory Commission. Docket No. ER14-456. On behalf of NextEra Energy to analyze a proposed modification to the PJM Tariff allowing for "easily resolved constraints" to be address by transmission upgrades without any analyses of benefits.

223-Federal Energy Regulatory Commission. Docket No. ER14-504. Affidavit on behalf of PJM Power Producers addressing the interaction between the PJM adequacy planning processes and the formulation of saturation constraints on Limited and Extended Summer Demand Response products.

222-Federal Energy Regulatory Commission. Docket AD13-7. Invited speaker on the Commission's technical session regarding capacity markets in RTO's. Comments addressed basic principles of market design, market features, and consequences of market failures and deviations from design principles.

221-Federal Energy Regulatory Commission. Docket No. EL13-62 on behalf of TC Ravenswood LLC. Two affidavits addressing the treatment of reliability support services agreements and associated capacity in the NYISO capacity market design.

2012

220-Federal Energy Regulatory Commission. Docket No. ER12-715-003. On behalf of First Energy Services Company. An affidavit and testimony addressing the appropriateness of the application of a proposed new MISO tariff provision after the fact to a withdrawing MISO member.

219-Federal Energy Regulatory Commission. Docket ER13-335. On behalf of Hydro Quebec U.S. Affidavit addressing appropriate application of ISO-NE Market Rule 1/ Tariff with respect to the qualification of new external capacity to participate in the Forward Capacity Market.

218-Federal Energy Regulatory Commission. Docket IN12-4. On behalf of Deutsche Bank Energy Trading. Affidavit regarding a review of specific transactions, related congestion revenue rights, and deficiencies in CAISO tariff implementation during periods when market software produces multiple feasible pricing solutions.

217-Federal Energy Regulatory Commission. Docket No. ER12-715-003. On behalf of FirstEnergy Services Company. Affidavit regarding implementation of the MISO Tariff with respect to the determination of appropriate exit fees and charges related to certain transmission facilities.

216-Federal Energy Regulatory Commission. Docket No. IN12-11. On behalf of Rumford Paper Company. Affidavit regarding free riding behavior in the design of demand response programs, and its relationship to accusations of market manipulation.

215-Federal Energy Regulatory Commission. Docket No. IN12-10. On behalf of Lincoln Paper and Tissue LLC. Affidavit regarding relationship of demand response behavior and value established in Order 745 to claimed market impacts associated with accusations of market manipulation.

214-Federal Energy Regulatory Commission. Docket No. AD12-16-000. On behalf of PJM Power Providers, testimony regarding deliverability of capacity between the MISO and PJM RTO's and associated basic adequacy planning concepts.

213-United States Court Of Appeals, District of Columbia Circuit. Electric Power Supply Asociation, et al (Petitioners) v. Federal Energy Regulatory Commission et al (Respondents) Nos. 11-1486. Amici Curiae brief regarding the appropriate pricing of demand reduction services in wholesale markets vis a vis the FERC determinations in Order 745.

212-United States Supreme Court. Metropolitan Edison Company and Pennsyvalnia electric Company (Petitioners), Pennsylvania Public Utility Commission (Respondent) (No. 12-4) Amici Curiae brief regarding the nature of physical losses in electric transmission and relationship to proper marginal cost pricing of electric power and the marginal cost of transmission service.

2011

211-Federal Energy Regulatory Commission Docket No. ER12-513-000. On behalf of PJM Power Providers, testimony regarding the establishment of system wide values for the net cost of new entry related to modifications of the Reliability Planning Model.

210-Federal Energy Regulatory Commission Docket No. EL11-56-000, on behalf of First Energy Services. Affidavit regarding the appropriateness of proposed transmission cost allocation of Multi-Value Projects to an exiting member of the Midwest Independent System Operator.

209-Federal Energy Regulatory Commission Docket No. ER11-4081-000, on behalf of "Capacity Suppliers". Affidavit addressing correct market design elements for Midwest Independent System Operator proposed resource adequacy market.

208-Public Utility Commission of Ohio, Case Nos. 11-346-EL-SSO,11-348-EL-SSO,Nos. 11-349-EL-AAM, 11-350-EL-AAM, on behalf of First Energy Services. Testimony regarding the interaction between the capacity default rates for retail access under the PJM Fixed Resource Requirement and the PJM Reliability Planning Model valuations.

207-Federal Energy Regulatory Commission Dockets No. ER11-2875, EL11-20, Staff Technical Conference on behalf of PJM Power Providers, addressing self supply and the Fixed Resource Requirement elements of PJM's capacity market design.

206-New Jersey Board of Public Utilities, Docket Number EO11050309 on behalf of PSEG Companies. Affidavit addressing the implications of markets and market design elements, and regulatory actions on the relative risk and trade-offs between capital versus energy intensive generation investments.

205-Federal Energy Regulatory Commission Docket No. ER11-2875. Affidavit and supplemental statement on behalf of PJM Power Providers addressing flaws in the PJM tariff's Minimum Offer Price Rule regarding new capacity entry and recommendations for tariff revisions.

204-Federal Energy Regulatory Commission Docket No. EL11-20. Affidavit on behalf of PJM Power Providers addressing flaws in the PJM tariff's Minimum Offer Price Rule regarding new capacity entry.

203-Federal Energy Regulatory Commission Docket Nos. ER04-449. Affidavit and supplemental statement on behalf of New York Suppliers addressing the appropriate criteria for the establishment of a new capacity zone in the NYISO markets.

2010

202-New Jersey State Assembly and Senate. Statements on behalf of the Competitive Supplier Coalition addressing market power and reliability impacts of proposed legislation, Assembly Bill 3442 and Senate Bill 2381.

201-Federal Energy Reglatory Commission. Docket ER11-2183. Affidavit on behalf of First Energy Services Company addressing default capacity charges for Fixed Resource Requirement participants in the PJM Reliability Pricing Model capacity market design.

200-Federal Energy Regulatory Commission. Docket ER11-2059 Affidavit on behalf of First Energy Services Company addressing deficiencies and computational problems in the proposed "exit charges" for transmission owners leaving the MISO RTO related to long term transmission rights.

199-Federal Energy Regulatory Commission Docket RM10-17. Invited panelist addressing metrics for cost effectiveness of demand response and associated cost allocations and implications for monopsony power.

198-Federal Energy Regualtory Commission Consolidated Dockets ER10-787-000, EL10-50-000, and EL10-57-000. Two affidavits on behalf of the New England Power Generators Association regarding ISO-NE modified proposals for alternative price rule mitigation and zonal definitions/functions of locational capacity markets.

197-Federal Energy Regulatory Commission Docket No. ER10-2220-000. Affidavit on behalf of the Independent Energy Producers of New York. Addressing rest of state mitigation thresholds and procedures for adjusting thresholds for frequently mitigated units and reliability must run units.

196-Federal Energy Regulatory Commission Docket PA10-1. Affidavit on behalf of Entergy Services related to development of security constrained unit commitment software and its performance.

195-Federal Energy Regulatory Commission Docket No. ER09-1063-004. Testimony on behalf of the PJM Power Providers Group (P3) regarding the proposed shortage pricing mechanism to be implemented in the PJM energy market. Reply comments related to a similar proposal by the independent market monitor.

194-PJM RTO. Statement regarding the impact of the exercise of buyer market power in the PJM RPM/Capacity market. Panel discussant on the issue at the associated Long Term Capacity Market Issues Sympossium.

193-Federal Energy Regulatory Commission Docket No. ER10-787-000. Affidavit on behalf of New England Power Generators Association addressing proper design of the alternative price rules (APR) for the ISO-NE Forward Capacity Auctions. Second affidavit offered in reply. Supplemental affidavit also submitted

192-Federal Energy Regulatory Commission Docket No. RM10-17-000. Affidavit on behalf of New England Power Generators Association addressing proper pricing for demand response compensation in organized wholesale regional transmissiom organizations.

191-Federal Energy Regulatory Commission Docket No. RM10-17-000, Affidavit on my on behalf regarding inconsistent representations made between filings in this docket and contemporaneous materials presented in the PJM stakeholder process.

2009

190-Federal Energy Regulatory Commission Docket No. ER09-1682. Two affidavits on behalf of an un-named party regarding confidential treatment of market data coupled with specific market participant bidding, and associated issues.

189-American Arbitration Assoication, Case No. 75-198-Y-00042-09 JMLE, on behalf of Rathdrum Power LLC. Report on the operation of specific pricing provision of a tolling power purchase agreement.

188-Federal Energy Regulatory Commission. Docket No. IN06-3-003. Analyses on behalf of Energy Transfer Partners L.P. regarding trading activity in physical and financial natural gas markets.

187-Federal Energy Regulatory Commission. Docket No. ER08-1281-000. Analyses on behalf of Fortis Energy Trading related to the impacts of loop flow on trading activities and pricing.

186-American Arbitration Association. Report on behalf of PEPCO Energy Services regarding several trading transactions related to the purchase and sale of Installed Capacity under the PJM Reliability Pricing Model.

185-Federal Energy Regulatory Commission Docket No. EL-0-47. Analyses on behalf of HQ Energy services (U.S.) regarding pricing and sale of energy associated with capacity imports into ISO-NE.

184-Federal Energy Regulatory Commission Docket No. ER04-449 019, Affidavit on behalf of HQ Energy Services (U.S.) regarding the implementation of the consensus deliverability plan for the NYISO, and associated reliability impacts of imports.

183-Federal Energy Regulatory Commission Docket ER09-412-000, ER05-1410-010, EL05-148-010. Affidavit and Reply Affidavit on behalf of PSEG Companies addressing proposed changes to the PJM Reliability Pricing Model and rebuttal related to other parties' filings.

2008

182-Pennsylvania Public Service Commission. *En Banc* Public Hearing on "Current and Future Wholesale Electricity Markets", comments regarding the design of PJM wholesale market pricing and state restructuring.

181-Maine Public Utility Commission. Docket No. 2008-156. Testimony on behalf of a consortion of energy producers and suppliers addressing the potential withdrawal of Maine from ISO New England and associated market and supplier response.

180-Federal Energy Regulatory Commission. Docket No. EL08-67-000. Affidavit on behalf of Duke Energy Ohio and Reliant Energy regarding criticisms of the PJM reliability pricing model (RPM) transitional auctions.

179-Federal Energy Regulatory Commission. Docket AD08-4, on behalf of the PJM Power Providers. Statement and participation in technical session regarding the design and operation of capacity markets, the status of the PJM RPM market and comments regarding additional market design proposals.

178-Federal Energy Regulatory Commission. Docket ER06-456-006, Testimony on behalf of East Coast Power and Long Island Power Authority regarding appropriate cost allocation procedures for merchant transmission facilities within PJM.

2007

177-FERC Docket No. EL07-39-000. Testimony on behalf of Mirant Companies and Entergy Nuclear Power Marketing regarding the operation of the NYISO In-City Capacity market and the associated rules and proposed rule modifications.

176-FERC Dockets: RM07-19-000 and AD07-7-000, filing on behalf of the PJM Power Providers addressing conservation and scarcity pricing issues identified in the Commission's ANOPR on Competition.

175-FERC Docket No. EL07-67-000. Testimony and reply comments on behalf of Hydro Quebec U.S. regarding the operation of the NYISO TCC market and appropriate bidding and competitive practices in the TCC and Energy markets.

174-FERC Docket Nos. EL06-45-003. Testimony on behalf of El Paso Electric regarding the appropriate interpretation of a bilateral transmission and exchange agreement.

2006

173-United States Bankruptcy Court for the Southern District of New York. Case No. 01-16034 (AJG). Report on Behalf of EPMI regarding the properties and operation of a power purchase agreement.

172-FERC Docket No. EL05-148-000. Testimony regarding the proposed Reliability Pricing Model settlement submitted for the PJM RTO.

171-FERC Docket No. ER06-1474-000, FERC. Testimony on behalf othe PSEG Companies regarding the PJM proposed new policy for including "market efficiency" transmission upgrades in the regional transmission expansion plan.

170-FERC Docket No. EL05-148-000, FERC. Participation in Commission technical sessions regarding the PJM proposed Reliability Pricing Model.

169-FERC Docket No. EL05-148-000, FERC. Comments filed on behalf of six PJM market participants concerning the proposed rules for participation in the PJM Reliability Pricing Model Installed Capacity market, and related rules for opting out of the RPM market.

168-FERC Docket No. ER06-407-000. Testimony on behalf of GSG, regarding interconnection issues for new wind generation facilities within PJM.

2005

167-FERC Docket No. EL05-121-000, Testimony on behalf of several PJM Transmission Owners (Responsible Pricing Alliance) regarding alternative regional rate designs for transmission service and associated market design issues.

166-FERC Technical Conference of June 16, 2005. (Docket Nos. PL05-7-000, EL03-236-000, ER04-539-000). Invited participant. Statement regarding the operation of the PJM Capacity market and the proposed new Reliability Pricing Model Market design.

165-American Arbitration Association Nos. 16-198-00206-03 16-198-002070.On behalf of PG&E Energy Trading. Analyses related to the operation and interpretation of power purchase and sale/tolling agreements and electrical interconnection requirements.

164-Arbitration on behalf of Black Hills Power, Inc. Expert testimony related to a power purchase and sale and energy exchange agreement, as well as FERC criteria related to the applicable code and standards of conduct.

2004

163-Federal Energy Regulatory Commission Docket No. EL03-236-003. Testimony on behalf of Mirant companies relating to PJM proposal for compensation of frequently mitigated generation facilities.

162-Federal Energy Regulatory Commission. Docket No. ER03-563-030. Testimony on behalf of Calpine Energy Services regarding the development of a locational Installed Capacity market and associated generator service obligations for ISO-NE. Supplemental testimony filed 2005.

161-Federal Energy Regulatory Commission. Docket No. EL04-135-000. Testimony on behalf on the Unified Plan Supporters regarding implications of using a flow based rate design to allocate embedded costs.

160-Federal Energy Regulatory Commission. Docket No. ER04-1229-000. Testimony on behalf of EME Companies regarding the allocation and recovery of administrative charges in the NYISO markets.

159-Federal Energy Regulatory Commission. Dockets No. EL01-19-000, No. EL01-19-001, No. EL02-16-000, EL02-16-000. Testimony on behalf of PSE&G Energy Resources and Trade regarding pricing in the New York Independent System Operator energy markets.

158-Federal Energy Regulatory Commission. Invited panelist regarding performance based regulation (PBR) and wholesale market design. Comments related to the potential role of PBR in transmission expansion, and its interaction with market mechanisms for new transmission.

157-Federal Energy Regulatory Commission. Docket No. ER04-539-000 Testimony on behalf of EME Companies regarding proposed market mitigation in the energy and capacity markets of the Northern Illinois Control Area.

156-Federal Energy Regulatory Commission. Standardization of Generator Interconnection Agreements and Procedures Docket No. RM02-1-001, Order 2003-A, Affidavit on Behalf of PSEG Companies regarding the modifications on rehearing to interconnection crediting procedures.

155-Federal Energy Regulatory Commission. Dockets ER03-236-000,ER04-364-000,ER04-367-000,ER04-375-000. Testimony on behalf of the EME Companies regarding proposed market mitigation measures in the Northern Illinois Control Area of PJM.

154-Federal Energy Regulatory Commission. Dockets PL04-2-000, EL03-236-000. Invited panelist, testimony related to local market power and the appropriate levels of compensation for reliability must run resources.

2003

153-American Arbitration Association. 16 Y 198 00204 03. Report on behalf of Trigen-Cinergy Solutions regarding an energy services agreement related to a cogeneration facility.

152-Federal Energy Regulatory Commission. Docket No. EL03-236-000. Testimony on behalf of EME Companies regarding the PJM proposed tariff changes addressing mitigation of local market power and the implementation of a related auction process.

151-Federal Energy Regulatory Commission. Docket No. PA03-12-000. Testimony on behalf of Pepco Holdings Incorporated regarding transmission congestion and related issues in market design in general, and specifically addressing congestion on the Delmarva Peninsula.

150-Federal Energy Regulatory Commission. Docket Nos. ER03-262-007, Affidavit on behalf of EME Companies regarding the cost benefit analysis of the operation of an expanded PJM including Commonwealth Edison.

149-Supreme Court of the State of New York, Index No. 601505/01. Report on behalf of Trigen-Syracuse Energy Corporation regarding energy trading and sales agreements and the operation of the New York Independent System Operator.

148-Federal Energy Regulatory Commission. Docket No. ER03-262-000. Affidavit on behalf of the EME Companies regarding the issues associated with the integration of the Commonwealth Edison Company into PJM.

147-Federal Energy Regulatory Commission. Docket No. ER03-690-000. Affidavit on behalf of Hydro Quebec US regarding New York ISO market rules at external generator proxy buses when such buses are deemed non-competitive.

146-Federal Energy Regulatory Commission. Docket RT01-2-006,007. Affidavit on behalf of the PSEG Companies regarding the PJM Regional Transmission Expansion Planning Protocol, and proper incentives and structure for merchant transmission expansion.

145-Federal Energy Regulatory Commission. Docket No. ER03-406-000. Affidavit on behalf of seven PJM Stakeholders addressing the appropriateness of the proposed new Auction Revenue Rights/Financial Transmission Rights process to be implemented by the PJM ISO.

144-Federal Energy Regulatory Commission. Docket No. ER01-2998-002. Testimony on behalf of Pacific Gas and Electric Company related to the cause and allocation of transmission congestion charges.

143-Federal Energy Regulatory Commission. Docket No. RM01-12-000. On behalf of six different companies including both independent generators, integrated utilities and distribution companies comments on the proposed resource adequacy requirements of the Standard Market Design.

142-United States Bankruptcy Court, Northern District of California, San Francisco Division, Case No. 01-30923 DM. On behalf of Pacific Gas and Electric Dr. Shanker presented testimony addressing issues related to transmission congestion, and the proposed FERC SMD and California MD02 market design proposals.

2002

141-Arbitration. Testimony on behalf of AES Ironwood regarding the operation of a tolling agreement and its interaction with PJM market rules.

140-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Dr. Shanker was asked by the three Northeast ISO's to present a summary of his resource adequacy proposal developed in the Joint Capacity Adequacy Group. This was part of the Standard Market Design NOPR process.

139-Federal Energy Regulatory Commission. Docket No. ER02-456-000. Testimony on behalf of Electric Gen LLC addressing comparability of a contract among affiliates with respect to non-price terms and conditions.

138-Circuit Court for Baltimore City. Case 24-C-01-000234. Testimony on behalf of Baltimore Refuse Energy Systems Company regarding the appropriate implementation and pricing of a power purchase agreement and related Installed Capacity credits.

137-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the characteristics of capacity adequacy markets and alternative market design systems for implementing capacity adequacy markets.

2001

136-Federal Energy Regulatory Commission. Docket ER02-456-000. Testimony on behalf of Electric Gen LLC regarding the terms and conditions of a power sales agreement between PG&E and Electric Generating Company LLC.

135-Delaware Public Service Commission. Docket 01-194. On behalf of Conectiv et al. Testimony relating to the proper calculation of Locational Marginal Prices in the PJM market design, and the function of Fixed Transmission Rights.

134-Federal Energy Regulatory Commission. Docket No. IN01-7-000 On behalf of Exelon Corporation . Testimony relating to the function of Fixed Transmission Rights, and associated business strategies in the PJM market system.

133-Federal Energy Regulatory Commission. Docket No. RM01-12-000. Comments on the basic elements of RTO market design and the required market elements.

132-Federal Energy Regulatory Commission. Docket No. RT01-99-000. On behalf of the One RTO Coalition. Affadavit on the computational feasibility of large scale regional transmission organizations and related issues in the PJM and NYISO market design.

131-Arbitration. On behalf of Hydro Quebec. Testimony related to the eligibility of power sales to qualify as Installed Capacitywithin the New York Independent system operator.

130-Virginia State Corporation Commission. Case No. PUE000584. On behalf of the Virginia Independent Power Producers. Testimony related to the proposed restructuring of Dominion Power and its impact on private power contracts.

129-United States District Court, Northern District of Ohio, Eastern Division, Case: 1:00CV1729. On behalf of Federal Energy Sales, Inc. Testimony related to damages in disputed electric energy trading transactions.

128-Federal Energy Regulatory Commission. Docket Number ER01-2076-000. Testimony on behalf of Aquila Energy Marketing Corp and Edison Mission Marketing and Trading, Inc. relating to the implementation of an Automated Mitigation Procedure by the New York ISO.

2000

127-New York Independent System Operator Board. Statement on behalf of Hydro Quebec, U.S. regarding the implications and impacts of the imposition of a price cap on an operating market system.

126-Federal Energy Regulatory Administration. Docket No. EL00-24-000. Testimony on behalf of Dayton Power and Light Company regarding the proper characterization and computation of regulation and imbalance charges.

125-American Arbitration Association File 71-198-00309-99. Report on behalf of Orange and Rockland Utilities, Inc. regarding the estimation of damages associated with the termination of a power marketing agreement.

124-Circuit Court, 15th Judicial Circuit, Palm Beach County, Florida. On behalf of Okeelanta and Osceola Power Limted Partnerships et. al. Analyses related to commercial operation provisions of a power purchase agreement.

1999

123-Federal Energy Regulatory Commission. Docket No. ER00-1-000. Testimony on behalf of TransEnergie U.S. related to market power associated with merchant transmission facilities. Also related analyses regarding market based tariff design for merchant transmission facilities.

122-Federal Energy Regulatory Commission. Docket RM99-2-000. Analyses on behalf of Edison Mission Energy relating to the Regional Transmission Organization Notice of Proposed Rulemaking.

121-Federal Energy Regulatory Commission. Docket No. ER99-3508-000. On behalf of PG&E Energy Trading, analyses associated with the proposed implementation and cutover plan for the New York Independent System Operator.

120-Federal Energy Regulatory Commission. Docket No. EL99-46-000. Comments on behalf of the Electric Power Supply Association relating to the Capacity Benefit Margin.

119-New York Public Service Commission, Case 97-F-1563. Testimony on behalf of Athens Generating Company describing the impacts on pricing and transmission of a new generation facility within the New York Power Pool under the new proposed ISO tariff.

118-JAMS Arbitration Case No. 1220019318 On behalf of Fellows Generation Company. Testimony related to the development of the independent power and qualifying facility industry and related industry practices with respect to transactions between cogeneration facilities and thermal hosts.

117-Court of Common Pleas, Philadelphia County, Pennsylvania. Analyses on behalf of Chase Manhattan Bank and Grays Ferry Cogeneration Partnership related to power purchase agreements and electric utility restructuring.

1998

116-Virginia State Corporation Commission. Case No. PUE 980463. Testimony on behalf of Appomattax Cogeneration related to the proper implementation of avoided cost methodology.

115-Virginia State Corporation Commission. Case No. PUE980462 Testimony on behalf of Virginia Independent Power Producers related to an applicaton for a certificate for new generation facilities.

114-Federal Energy Regulatory Commission. Analyses related to a number of dockets reflecting amendments to the PJM ISO tariff and Reliability Assurance Agreement.

113-U.S. District Court, Western Oklahoma. CIV96-1595-L. Testimony related to anti-competitive elements of utility rate design and promotional actions.

112-Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Analyses related to historic measurement of spot prices for as available energy.

111-Circuit Court, Fourth Judicial Circuit, Duval County, Florida. Analyses related to the proper implementation of a a power purchase agreement and associated calculations of capacity payments. (Testimony 1999)

1997

110-United States District Court for the Eastern District of Virginia, CA No. 3:97CV 231. Analyses of the business and market behavior of Virginia Power with respect to the implementation of wholesale electric power purchase agreements.

109-United States District Court, Southern District of Florida, Case No. 96-594-CIV, Analyses related to anti-competitive practices by an electric utility and related contract matters regarding the appropriate calculation of energy payments.

108-Virginia State Corporation Commission. Case No. PUE960296. Testimony related to the restructuring proposal of Virginia Power and associated stranded cost issues.

107-Federal Energy Regulatory Commission. Dockets No. ER97-1523-000 and OA97-470-000, Analyses related to the restructuring of the New York Power Pool and the implementation of locational marginal cost pricing.

106-Federal Energy Regulatory Commission Dockets No. OA97-261-000 and ER97-1082-000 Analyses and testimony related to the restructuring of the PJM Power Pool and the implementation of locational marginal cost pricing.

105-Missouri Public Service Commission. Case No. ET-97-113. Testimony related to the proper definition and rate design for standby, supplemental and maintenance service for Qualifying facilities.

104-American Arbitration Association. Case 79 Y 199 00070 95. Testimony and analyses related to the proper conditions necessary for the curtailment of Qualifying Facilities and the associated calculations of negative avoided costs.

103-Virginia State Corporation Commission. Case Number PUE960117 Testimony related to proper implementation of the differential revenue requirements methodology for the calculation of avoided costs.

102-New York Public Service Commission. Case 96-E-0897, Analyses related to the restructuring of Consolidated Edison Company of New York and New York Power Pool proposed Independent System Operator and related transmission tariffs.

1996

101-Florida Public Service Commission. Docket No. 950110-EI. Testimony related to the correct calculation of avoided costs using the Value of Deferral methodology and its implementation.

100-Federal Energy Regulatory Commission Dockets No. EL94-45-001 and QF88-84-006. Testimony and Analyses related to the estimation of historic market rates for electricity in the Virginia Power service territory.

99-Circuit Court of the City of Richmond Case No. LA-2266-4. Analyses related to the incurrence of actual and estimated damages associated with the outages of an electric generation facility.

98-New Hampshire Public Utility Commission, Docket No. DR96-149. Analyses related to the requirements of light loading for the curtailment of Qualifying Facilities, and the compliance of a utility with such requirements.

97-State of New York Supreme Court, Index No. 94-1125. Testimony related to system planning criteria and their relationship to contract performance specifications for a purchased power facility.

96-United States District Court for the Western District of Pennsylvania, Civil Action No. 95-0658. Analyses related to anti-competitive actions of an electric utility with respect to a power purchase agreement.

95-United States District Court for the Northern District of Alabama, Southern Division. Civil Action Number CV-96-PT 0097-S. Affadavit on behalf of TVA and LG&E Power regarding displacement in wholesale power transactions.

1995

94-American Arbitration Association. Arbitration No. 14 198 012795 H/K. Report concerning the correct measurement of savings resulting from a commercial building cogeneration system and associated contract compensation issues.

93-Circuit Court City of Richmond. Law No. LX-2859-1. Analyses related to IPP contract structure and interpretation regarding plant compensation under different operating conditions.

92-Federal Energy Regulatory Commission. Case EL95-28-000. Affidavit concerning the provisions of the FERC regulations related to the Public Utility Regulatory Policies Act of 1978, and relationship of estimated avoided cost to traditional rate based recovery of utility investment.

91-New York Public Service Commission, Case 95-E-0172, Testimony on the correct design of standby, maintenance and supplemental service rates for qualifying facilities.

90-Florida Public Service Commission, Docket No. 941101-EQ. Testimony related to the proper analyses and procedures related to the curtailment of purchases from Qualifying Facilities under Florida and FERC regulations.

89-Federal Energy Regulatory Commission, Dockets ER95-267-000 and EL95-25-000. Testimony related to the proper evaluation of generation expansion alternatives.

1994

88-American Arbitration Association, Case Number 11 Y198 00352 94 Analyses related to contract provisions for milestones and commercial operation date and associated termination and damages related to the construction of a NUG facility.

87-United States District Court, Middle District Florida, Case No. 94-303 Civ-Orl-18. Analyses related to contract pricing interpretation other contract matters in a power purchase agreement between a qualifying facility and Florida Power Corporation.

86-Florida Public Service Commission Docket 94037-EQ. Analyses related to a contract dispute between Orlando Power Generation and Florida Power Corporation.

85-Florida Public Service Commission Docket 941101-EQ. Testimony and analyses of the proper procedures for the determination and measurement for the need to curtail purchases from qualifying facilities.

84-New York Public Service Commission Case 93-E-0272, Testimony regarding PURPA policy considerations and the status of services provided to the generation and consuming elements of a qualifying facility.

83-Circuit Court for the City of Richmond. Case Number LW 730-4. Analyses of the historic avoided costs of Virginia Power, related procedures and fixed fuel transportation rate design.

82-New York Public Service Commission, Case 93-E-0958 Analyses of Stand-by, Supplementary and Maintenance Rates of Niagara Mohawk Power Corporation for Qualifying Facilities .

81-New York Public Service Commission, Case 94-E-0098. Analyses of cost of service and rate design of Niagara Mohawk Power Corporation.

80-American Arbitration Association, Case 55-198-0198-93, Arbitrator in contract dispute regarding the commercial operation date of a qualifying small power generation facility.

1993

79-U.S. District Court, Southern District of New York Case 92 Civ 5755. Analyses of contract provisions and associated commercial terms and conditions of power purchase agreements between an independent power producer and Orange and Rockland Utilities.

78-State Corporation Commission, Virginia. Case No. PUE920041. Testimony related to the appropriate evaluation of historic avoided costs in Virginia and the inclusion of gross receipt taxes.

77-Federal Energy Regulatory Commission. Docket ER93-323-000. Evaluations and analyses related to the financial and regulatory status of a cogeneration facility.

76-Federal Energy Regulatory Commission. Docket EL93-45-000; Docket QF83-248-002. Analyses related to the qualifying status of cogeneration facility.

75-Circuit Court of the Eleventh Judicial Circuit, Dade County, Florida. Case No. 92-08605-CA-06. Analyses related to compliance with electric and thermal energy purchase agreements. Damage analyses and testimony.

74-Board of Regulatory Commissioners, State of New Jersey. Docket EM 91010067. Testimony regarding the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

73-State of North Carolina Utilities Commission. Docket No. E-100 Sub 67. Testimony in the consideration of rate making standards pursuant to Section 712 of the Energy Policy Act of 1992.

72-State of New York Public Service Commission. Cases 88-E-081 and 92-E-0814. Testimony regarding appropriate procedures for the determination of the need for curtailment of qualifying facilities and associated proper production cost modeling and measurement.

71-Pennsylvania Public Utility Commission. Docket No. A-110300f051. Testimony regarding the prudence of the revised GPU/Duquesne 500 MW power sales agreement and associated transmission line.

1992

70-Pennsylvania Public Service Commission. Dockets No. P-870235,C-913318,P-910515,C-913764. Testimony regarding the calculation of avoided costs for GPU/Penelec.

69-Public Service Commission of Maryland. Case No. 8413,8346. Testimony on the appropriate avoided costs for Pepco, and appropriate procedures for contract negotiation.

1991

68-Board of Regulatory Commissioners, State of New Jersey. Docket EM-91010067. Testimony regarding the planned purchase of 500 MW by GPU from Duquesne Light Company.

67-Public Service Commission of Wisconsin. Docket 05-EP-6. State Advance Plan. Testimony on the calculation of avoided costs and the structuring of payments to qualifying facilities.

66-State Corporation Commission, Virginia. Case No. PUE910033. Testimony on class rate of return and rate design for delivery point service. Northern Virginia Electric Cooperative.

65-State Corporation Commission, Virginia. Case No. PUE910048 Testimony on proper data and modeling procedures to be used in the evaluation of the annual Virginia Power fuel factor.

64-State Corporation Commission, Virginia. Case No. PUE910035. Evaluation of the differential revenue requirements method for the calculation of avoided costs.

63-Public Service Commission of Maryland. Case Number 8241 Phase II. Testimony related to the proper determination of avoided costs for Baltimore Gas and Electric.

62-Public Service Commission of Maryland. Case Number 8315. Evaluation of the system expansion planning methodology and the associated impacts on marginal costs and rate design, PEPCO.

1990

61-Public Utility Commission, State of California, Application 90-12-064. Analyses related to the contractual obligations between San Diego Gas and Electric and a proposed QF.

60-Montana Public Service Commission. Docket 90.1.1 Testimony and analyses related to natural gas transportation, services and rates.

59-State Corporation Commission, Virginia. Case No. PUE890075. Testimony on the calculation of full avoided costs via the differential revenue requirements methodology.

58-District of Columbia Public Service Commission. Formal Case 834 Phase II. Analyses and development of demand side management programs and least cost planning for Washington Gas Light.

57-State Corporation Commission, Virginia. Case No. PUE890076. Analyses related to administratively set avoided costs. Determination of optimal expansion plans for Virginia Power.

56-State Corporation Commission, Virginia. Case No. PUE900052. Analyses supporting arbitration of a power purchase agreement with Virginia Power. Determination of expansion plan and avoided costs.

55-Public Service Commission of Maryland. Case Number 8251. Analyses of system expansion planning models and marginal cost rate design for PEPCO.

54-State Corporation Commission, Virginia. Case No. PUE900054. Evaluation of fuel factor application and short term avoided costs.

53-Federal Energy Regulatory Commission. Northeast Utilities Service Company Docket Nos. EC90-10-000, ER90-143-000, ER90-144-

000,ER90-145-000 and El90-9-000. Analyses of the implications of Northeast Utilities and Public Service Company of New Hampshire merger on electric supply and pricing.

52-Public Service Commission of Maryland. Re: Southern Maryland Electric Cooperative Inc. Contract with Advanced Power Systems, Inc. and PEPCO.

51-Puerto Rico Electric Power Authority, Office of the Governor of Puerto Rico. Independent evaluation for PREPA of avoided costs and the evaluation of competing QF's.

50-State Corporation Commission, Virginia. Case No. PUE890041. Testimony on the proper determination of avoided costs with respect to Old Dominion Electric Cooperative.

1989

49-Oklahoma Corporation Commission. Case Number PUD-000586. Analyses related to system planning and calculation of avoided costs for Public Service of Oklahoma.

48-Virginia State Corporation Commission. Case Number PUE890007. Testimony relating to the proper determination of avoided costs to the certification evaluation of new generation facilities.

47-Federal Energy Regulatory Commission. Docket RP85-50. Analyses of the gas transportation rates, terms and conditions filed by Florida Gas Transmission.

46-Circuit Court of the Fifth Judicial Circuit, Dade County, Florida. Case No. 88-48187. Analyses related to compliance with electric and thermal energy purchase agreements.

45-Florida Public Service Commission. Docket 880004-EU. Analysis of state wide expansion planning procedures and associated avoided unit.

1988

44-Virginia State Corporation Commission. Case No. PUE870081. Testimony on the implementation of the differential revenue requirements avoided costmethodology recommended by the SCC Task Force.

43-Virginia State Corporation Commission. Case No. PUE880014. Testimony on the design and level of standby, maintenance and supplemental power rates for qualifying facilities.

42-Virginia State Corporation Commission. Case No. PUE99038. Testimony on the natural gas transportation rate design and service provisions.

41-Montana Public Service Commission. Docket 87.8.38. Testimony on Natural Gas Transmission Rate Design and Service Provisions.

40-Oklahoma Corporation Commission. Cause Pud No. 00345. Testimony on estimation and level of avoided cost payments for qualifying facilities.

39-Florida Public Service Commission. Docket No.8700197-EI. Testimony on the methodology for establishing non-firm load service levels.

38-Arizona Corporation Commission. Docket No. U-1551-86-300. Analysis of cost-of-service studies and related terms and conditions for material gas transportation rates.

1987

37-Virginia State Corporation Commission. Case No. PUE870028. Analysis of Virginia Power fuel factorapplication and relationship to avoided costs.

36-District of Columbia Public Service Commission. Formal Case No. 834 Phase II. Analysis of the theory and empirical basis for establishing cost effectiveness of natural gas conservation programs.

35-Virginia State Corporation Commission. Case No. PUE860058. Testimony on the relationship of small power producers and cogenerators to the need for power and new generation facilities.

34-Virginia State Corporation Commission. Case No. PUE870025. Testimony addressing the proper design of rates for standby, maintenance and supplement power sales to cogenerators.

33-Florida Public Service Commission. Docket No. 860004 EU. Testimony in the 1986 annual planning hearing on proper system expansion planning procedures.

1986

32-Florida Public Service Commission. Docket No. 860001 EI-E. Testimony on the proper methodology for the estimation of avoided O&M costs.

31-Florida Public Service Commission. Docket No. 860786-EI. Testimony on the proper economic analysis for the evaluation of self-service wheeling.

30-U.S. Bankruptcy Court, District of Ohio. Testimony on capabilities to develop and operate wood-fired qualifying facility.

29-Public Utility Commission, New Hampshire Docket No. DR-86-41. Testimony on pricing and contract terms for power purchase agreement between utility and QFs. (Settlement Negotiations)

28-Florida Public Service Commission, Docket No. 850673-EU. Testimony on generic issues related to the design of standby rates for qualifying facilities.

27-Virginia State Corporation Commission. Case No. 860024. Generic hearing on natural gas transportation rate design and tariff terms and conditions.

26-Virginia State Corporation Commission. Commonwealth Gas Pipeline Corporation. Case No. 850052. Testimony on natural gas transportation rate design and tariff terms and conditions.

25-Bonneville Power Administration. Case No. VI86. Testimony on the proposed Variable Industrial Power Rate for Aluminum Smelters.

24-Virginia Power. Case No. PUE860011. Testimony on the proper ex post facto valuation of avoided power costs for qualifying facilities.

23-Florida Public Service Commission. Docket No. 850004 EU. Testimony on proper analytic procedures for developing a statewide generation expansion plan and associated avoided unit.

1985

22-Virginia Natural Gas. Docket No. 85-0036. Testimony and cost of service procedures and rate design for natural gas transportation service.

21-Arkansas Louisiana Gas. Louisiana Docket No. U-16534. Testimony on proper cost of service procedures and rate design for natural gas service.

20-Connecticut Light and Power. Docket No. 85-08-08.
Assist in the development of testimony for industrial natural gas transportation rates.

19-Oklahoma Gas and Electric. Cause 29727. Testimony and system operations and the development of avoided cost measurements as the basis for rates to qualifying facilities.

18-Florida Public Service Commission. Docket No. 840399EU. Testimony on self-service wheeling and business arrangements for qualifying facilities.

17-Virginia Electric and Power Company. General Rate application No. PUE840071. Testimony on proper rate design procedures and computations for development of supplemental, maintenance and standby service for cogenerators.

16-Virginia Electric and Power Company. Fuel Factor Proceeding No. PUE850001. Testimony on the proper use of the PROMOD model and associated procedures in setting avoided cost energy rates for cogenerators.

15-New York State Public Service Commission. Case No. 28962. Development of the use of multi-area PROMOD models to estimate avoided energy costs for six private utilities in New York State.

14-Vermont Rate Hearings on Payments to Small Power Producers. Case No. 4933. Testimony on proper assumptions, procedures and analysis for the development of avoided cost rates.

1984

13-Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-serviceprocedures, class rate of return and rate design.

12-BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on theory and implementation of marginal cost rate design.

11-Virginia Electric Power Company. Application to Revise Rate Schedule 19 -- Power Purchases from Cogeneration and Small Power Production Qualifying Facilities. Case No. PUE830067. Testimony on proper PROMOD modeling procedures for power purchases and properties of PROMOD model.

10-Northern Virginia Electric Cooperative. Case No. PUE840041. Testimony on class cost-of-service procedures, class rate of return and rate design.

9-BPA 1985 Wholesale Rate Proceedings. Analysis of Power 1985 Rate Directives. Testimony on the theory and implementation of marginal cost rate design, financial performance of BPA; interactions between rate design, demand, system expansion and operation.

1983

8-Northern Virginia Electric Cooperative. Case No. PUE830040. Testimony on class cost-of-service procedures, class rate of return and rate design.

7-Vermont Rate Hearings to Small Power Producers. No.4804. Testimony on proper use and application of production costing analyses to the estimation of avoided costs.

6-BPA Wholesale Rate Proceedings. Testimony on the theory and implementation of marginal cost rate design; financial performance of BPA; interactions between rate design, demand, system expansion and operation.

5-Idaho Power Company, PUC-U-1006-185. Analysis of system planning/production costing model play of hydro regulation and associated energy costs.

1982

4-Generic Conservation Proceedings, New York State. Case No. 18223. Testimony on the economic criteria for the evaluation of conservation activities; impacts on utility financial performance and rate design.

3-PEPCO, Washington Gas Light. DCPSC-743. Financial evaluation of conservation activities; procedures for cost classification, allocation; rate design.

2-PEPCO, Maryland PSC Case Nos. 7597-I, 7597-II, and 7652. Testimony on class rates of return, cost classification and allocation, power pool operations and sales.

1981

1-Pacific Gas and Electric. California PSC Case No. 60153. Testimony on rate design; class cost-of-service and rate of return.

Previous testimony before the District of Columbia Public Service Commission, Maryland PSC, New York Public Service Commission, FERC; Economic Regulatory Administration