UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Fern Solar LLC	)))	Docket Nos. ER20-2186-003 and EL20-62-001

To: The Honorable Scott Hempling
Presiding Administrative Law Judge

INITIAL BRIEF OF THE INDEPENDENT MARKET MONITOR FOR PJM

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Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C. ("PJM"), submits this initial brief. For the reasons explained on brief, Fern Solar LLC ("Fern") has not shown that its proposed rate for its facility ("Fern Facility") satisfies the requirements to receive compensation under Schedule 2 to the PJM Open Access Transmission Tariff ("Schedule 2").[1] The record shows that the Fern Facility does not meet the Schedule 2 requirements. The record does not demonstrate any cost incurred by Fern in order to provide reactive supply capability unrelated to obligations under its interconnection service agreement with PJM. As the Commission confirmed in *Midcontinent Independent System Operator, Inc.*, issued January 27, 2023 ("*MISO*"), RTOs and their customers are not required to pay costs that generators incur in order to obtain interconnection service.[2] The proposed revenue requirement for the Fern Facility should be not be approved. The appropriate reactive revenue requirement for the Fern Facility is zero.

If the Fern Facility is nevertheless found to be entitled to a revenue requirement under Schedule 2 based on the *AEP* Method,[3] such revenue requirement should not exceed $2,199 per MW-Year, because a rate above that level, considered in conjunction with the opportunity to receive market revenues, would result in an over recovery.

To the extent that a rate method using a capital recovery factor ("CRF") is permitted, the CRF proposed by Fern is excessive and unjustified, and the CRF should be

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1 *See*. IMM-0002.

2 *See Midcontinent Independent System Operator, Inc.*, 182 FERC ¶ 61,033 at P 52 (January 27, 2023) ("*MISO*").

3 *See* FER-0057 (*American Electric Power Service Corporation*, Opinion No. 440, Docket No. ER93-540; 88 FERC ¶ 61,141 (1999), *withdrawal of reh'g granted*, 92 FERC ¶ 61,001 (2000) ("*AEP*")). The "*AEP* Method" refers to the method for allocation generation costs between generation and transmission accounts in testimony provided by Bernard M. Pasternack, Docket No. ER93-540.

calculated instead based on the method proposed by the Market Monitor.

I. SUMMARY

In this brief, the Market Monitor explains its position on five issues:

Whether Fern has supported, and has overcome evidence that it has not supported, entitlement to receive compensation for reactive supply capability under Schedule 2 above zero dollars. The record in this proceeding does not support a revenue requirement under Schedule 2 above zero dollars. A rate exceeding zero dollars would be unjust and unreasonable based on the record.[4]

Whether, if Fern has supported entitlement to any rate above zero dollars based on the *AEP* Method, the level of the rate proposed by Fern is unjust and unreasonable because it allows for over recovery. The Fern Facility participates in a competitive market design that provides an opportunity to recover all its costs, including reactive costs. The capacity market design (VRR curve) anticipates that resources will receive $2,199 per MW-Year in compensation for reactive supply capability and removes that amount from the market design parameters. To the extent that Fern proposes a revenue requirement exceeding $2,199 per MW-Year, it is seeking an unjust and unreasonable excess recovery. If any rate is accepted, no rate under Schedule 2 should be approved that exceeds $2,199 per MW-Year.

Whether, if Fern has supported entitlement to any rate above zero dollars, Fern properly uses the *AEP* Method to calculate a cost based revenue requirement under Schedule 2. Fern has not identified any costs that are not already recoverable under the PJM market design and would therefore be includable in a revenue requirement under Schedule 2. The *AEP* Method is not an appropriate basis for calculating a revenue requirement under Schedule 2. Prior decisions allowing the *AEP* Method did not find that or explain how the method operates to identify incremental costs for providing reactive

4 *See*, *e.g.*, *MISO*.

supply capability. The *AEP* Method does not define incremental costs. Fern did not attempt to identify incremental costs. The *AEP* Method is a cost of service allocation method that was not designed to implement Schedule 2 or for use in competitive markets.[5] The *AEP* Method was not designed for use with solar resources, and it should not be used for such resources. The *AEP* Method is not appropriate for calculating a revenue requirement under Schedule 2 and its use should be rejected.

Whether, even if the *AEP* Method applies to thermal resources, the *AEP* Method applies to a solar facility like the Fern Facility. If the *AEP* Method is used at all in this case, the approach should include the modifications to the relevant equipment proposed by Staff.

Whether, if Fern has supported entitlement to any rate above zero dollars, Fern properly calculated its capital recovery factor ("CRF"). The CRF calculated by Fern is flawed and should not be approved. If it is determined that a method that includes a CRF should be used in this case, the Market Monitor's proposed just, reasonable and nondiscriminatory approach should be required.

II. CONTEXT: FACTS, STATUTES AND POLICIES

A. The Fern Facility.

This proceeding concerns the proposed annual revenue requirement ("ARR") filed in this proceeding by Fern Solar LLC ("Fern") under Schedule 2 for its 100 MW solar generating facility located in Tarboro, North Carolina ("Fern Facility").[6]

The Fern Facility is an Exempt Wholesale Generator.[7]

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[5] *See* FER-0055 (*American Electric Power Service Corporation*, Opinion No. 440, 88 FERC ¶ 61,141 (1999), *withdrawal of reh'g granted*, 92 FERC ¶ 61,001 (2000) ("*AEP*")).

[6] *See* FER-0066 (*Fern Solar LLC*, 172 FERC ¶ 61,160 at P 3 (August 25, 2020) ("Hearing Order")).

Fern is a party to an interconnection agreement among itself, PJM, and Virginia Electric and Power Company, which obligates it to produce reactive power ("Fern ISA").[8]

B. The Statutory Context: A Section 206 Proceeding to Determine the Lawfulness of a Section 205 Filed Rate.

This proceeding comes before the Presiding Judge under both Sections 205 and 206 of the Federal Power Act. The rate took effect under Section 205 by operation of law. The Commission set the rate for investigation under Section 206 before the Section 205 proceeding concluded.[9] Intervenors accept the burden of persuasion under Section 206.

There is no prior finding for Fern on the merits on any issue raised in this case. That the rate in this proceeding took effect by operation of law should not determine the outcome of any issue. Neither issue preclusion, nor collateral estoppel, applies to any issue in this case.[10] Each issue must be decided on the merits.

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7 *Id*.

8 *Id.* at P 4.

9 *Id*. at P 13.

10 *See, e.g.*, Texas Employers' Ins. Asso. v. Jackson, 862 F.2d 491, 500 (5th Cir. 1988) ("Collateral estoppel, or "issue preclusion," requires, among other things, that the allegedly precluded issue have been "actually litigated and determined" in the prior action."); *citing*, *e.g.*, Lawlor v. National Screen Service Corp., 349 U.S. 322 (1955) ("collateral estoppel . . . precludes relitigation of issues actually litigated and determined in the prior suit"); Montana v. United States, 440 U.S. 147 (1979); Liona Corp. v. PCH Assocs. (In re PCH Assocs.), 949 F.2d 585, 593 (2nd Cir. 1991) ("With respect to issue preclusion, it must be remembered that for the doctrine to be properly invoked the particular issue currently in dispute must have been "both actually litigated and actually decided.").

C. Generators' Obligation: Provide Reactive Power Capability.

In order to receive interconnection service from PJM, generation resources must assume certain obligations under an interconnection service agreement (ISA).[11] The Fern ISA is an example of such an interconnection service agreement. It is well settled that a resource's obligation to provide reactive supply capability under an interconnection service agreement does not create an entitlement to receive compensation from the RTO.[12] It is also well settled that customers are not required to pay a separate

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[11] *See, e.g.*, OATT Attachment O.

[12] *See MISO* at P 52 ("We find that MISO TOs' proposed Schedule 2 revisions to eliminate compensation for its own and affiliated generation resources and unaffiliated generation resources and the associated charges to transmission customers, is permitted under, and consistent with Order Nos. 2003 and 2003-A."); *see also Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546 (2003) ("[T]he Interconnection Customer should not be compensated for reactive power when operating its Generating Facility within the established power factor range, since it is only meeting its obligation."), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28 ("[T]he provision of sufficient reactive power is an obligation of a generator interconnected to the system, and . . . as a general matter, a generator is not entitled to separate compensation for providing reactive power within its deadband."), *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); *California ISO*, 160 FERC ¶ 61,035 at P 19 (2017) ("[T]here is no compensation for any generators for providing reactive power capability inside the standard power factor range… A separate payment for the provision of reactive power capability inside the standard power factor range is not required, and we see no reason to require a separate cost recovery mechanism for reactive power capability…"); *Southwest Power Pool, Inc.*, 119 FERC ¶ 61,199 at P 28 (2007) ("[T]he provision of sufficient reactive power is an obligation of a generator interconnected to the system, and that, as a general matter, a generator is not entitled to separate compensation for providing reactive power within its deadband."), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also Public Service Company of New Mexico*, 178 FERC ¶ 61,088, at PP 29–31 (2022); *Nevada Power Co.*, 179 FERC ¶ 61,103, at PP 20-21 (2022).

transmission service charge for reactive supply capability.[13] Fern's reliance on its asserted entitlement to compensation based on meeting obligations it assumed as a condition for receipt of interconnection service from PJM is misplaced.[14]

Reactive Supply and Voltage Control Service is necessary to ensure a Transmission Provider's (PJM) reliable operation of the grid. Reactive supply includes the ability of a resource to produce reactive power (measured in MVAR) so that the Transmission Provider can provide Reactive Supply and Voltage Control Service. Reactive power is local and cannot be transferred over long distances.[15]

Under Schedule 2, PJM may procure reactive supply capability from generators located on the transmission system that it monitors and operates in support of PJM's provision of Reactive Supply and Voltage Control from Generation or Other Sources Service ("Schedule 2 Service") to its customers.[16] PJM is the Transmission Provider

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[13] *Id*. The Presiding Judge and Dr. Bowring discussed this issue at hearing, prior to the issuance of the decision accepting MISO's elimination of the equivalent of Schedule 2 from the MISO market rules. *See* Tr. at 3393:9–3394:13.

[14] Tr. 809:20–810:2 ("Q [Presiding Judge] So I think what you're going to say is that because the Commission in Order 827 imposed an obligation to make reactive power available at that location, we now have to compensate for that obligation. And the way that we compensate for that obligation is through this proceeding. Is that fundamentally your reasoning, is that your matching obligations of compensation, Mr. Bethel? A [Fern Witness Bethel] It is. ….").

[15] *See Whitetail Solar 3, LLC, et al.*, Initial Decision, 180 FERC ¶ 63,009 at P 24 (2022). Schedule 2 states: "In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power."

[16] Schedule 2 originated in Schedule 2 to the Pro Forma OATT included in Order No. 888. *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC ¶ 61,080, 61 FR 21540 at 28581–28532, *clarified*, 76 FERC ¶ 61,009 (1996) ("Order

under the OATT solely responsible to provide Schedule 2 Service.[17] [18] [19] Ancillary services, such as Schedule 2, are a form of transmission service.[20]

No. 888"), *modified*, Order No. 888-A, 78 FERC ¶ 61,220, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom.* Transmission Access Policy Study Grp. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.* New York v. FERC, 535 U.S. 1 (2002).

[17] OATT § 1 defines "Transmission Provider" as follows:

The "Transmission Provider" shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

(a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;

(b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and

(c) … Transmission Owners shall have the responsibility … to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Subsection (a) excludes from PJM's role the direction of "those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations."

[18] The OATT § 1 defines the "Transmission System" to "mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III."

[19] The OA § 1 (Definitions S–T) and OATT § 1 (Definitions–T–U–V) define "Transmission Facilities" to mean: "facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the

Generation resources are not transmission providers and do not provide Schedule 2 Service to PJM customers, even when their capability is relied upon by PJM when PJM provides Schedule 2 Service.

Schedule 2 does not require or include any method for calculating a reactive revenue requirement, including the *AEP* Method. Schedule 2 refers only to a "monthly revenue requirement as accepted or approved by the Commission."[21] That revenue requirement should be zero.

Any separate compensation for reactive supply capability is determined under a filing submitted by the generation resource directly to the Commission under Schedule 2. Neither PJM, nor the Market Monitor, nor any other entity, makes any prior determination on whether an entity is eligible to submit such a filing or whether any asserted cost requested for recovery under such filing is eligible for recovery. The record in this case does not show a single dollar of cost of the Fern Facility that is not recoverable through markets. The record in this proceeding does not show that Fern was required to incur any incremental cost in order to provide reactive supply capability. Regardless, costs incurred in order to receive interconnection service are not properly recovered under Schedule 2.

Schedule 2 also states the separate compensation that applies to market sellers that increase reactive output at the direction of PJM. Schedule 2 explains that when PJM calls on a resource to increase reactive power output, the resource is paid directly for the resultant energy market lost opportunity costs under Section 3.2.3B of Schedule 1 to the

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PJM Region to serve all of the power and transmission customers within the PJM Region."

20 *See* Order No. 888 *mimeo* at 204–205.

21 *See* IMM-0002.

OA. As Schedule 2 states, these charges and payments are separate from the revenue requirement for reactive supply capability in Schedule 2.

D. Generators’ Compensation: The *AEP* Method

1. What is the *AEP* Method?

a. The AEP Method Is an Arbitrary Method of Cost Allocation.

Fern purports to use this method to calculate its proposed revenue requirement for the Fern Facility. The Presiding Judge has requested that the participants explain what the *AEP* Method is. Whether and/or how the *AEP* Method should be applied in Schedule 2 proceedings is an important and unresolved issue.

The Presiding Judge has provided in the Bench Question B-2-23 the core statement of the *AEP* Method. Bench Question B-2-23 quotes AEP Witness Pasternack’s “terse” explanation of “his chosen reactive power allocator” in his 1993 testimony.[22] The Presiding Judge summarizes Mr. Pasternack’s statement:

> He stated first that the 'size and cost of the generator/exciter and accessory electric equipment are proportional to the MVA rating of that equipment.’ He then presented the basic power triangle relationship, $MVA^2=MW^2+MVAr^2$. Then he concluded: ‘Therefore, the portion of the MVA-based cost related to MVAr production would be $MVAr^2$ /MVA^2.’

But, as Dr. Bowring explained:

> [T]he basic power triangle relationship … has nothing to do with costs. The costs that provide reactive could be 1 percent of a power plant. It could be zero percent, and that relationship would still be true.[23]

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22 *See* FER-0012 (*American Electric Power Service Corporation*, Direct Testimony of Bernard M. Pasternack, Docket No. ER93-540-000 (November 15, 1993)).

23 Tr. at 3391:5–8.

The Presiding Judge, while reserving final judgment, identified a related basic logical error:

> While there may be engineering logic to using that ratio to determine, from an engineering—an electrical engineering standpoint, the contribution of equipment to the production of reactive power, that engineering logic doesn't automatically translate into a cost relationship.[24]

But there is no engineering logic that leads to a conclusion about the share or identification of the plant's physical equipment needed to provide reactive. Dr. Bowring responded that the flaw is more than a failed translation:

> I'm saying that there is no logical relationship, no causal relationship between the basic electrical engineering equation, the definition of power factor, the definition of power factor squared, and the cost to provide real and reactive power.[25]

Put another way, the basic power triangle relationship has nothing to do with actual equipment. The equipment that provides reactive could be 1.0 percent of a power plant. It could be zero percent, and that power triangle relationship would still be true. The power triangle relationship would still be true if it were not possible, as it is not, to identify a single piece of equipment, the sole purpose of which is to provide reactive.

As applied by Fern and other market participants, the *AEP* Method is designed to maximize the allocation of costs to reactive and therefore maximize the level of risk free guaranteed payments for reactive and minimize the costs incorporated in the PJM markets. This also means that, as applied by Fern and other market participants, the *AEP* Method is designed to minimize the allocation of costs to the provision of energy.

As Dr. Bowring explained at hearing:

> [O]ne of the issues with the way reactive is compensated is there is an incentive to maximize the amount of revenue

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[24] Tr. 3391:17–21.

[25] Tr. 3391:23–3392:2.

> collected from the reactive si[d]e, because it's a cost-of-service guarantee[d] riskless payment that's inconsistent with the basic market design of PJM.[26]

The *AEP* Method unjustly and unreasonably harms competition, harms market efficiency, harms PJM customers and harms the public interest because it arbitrarily forces customers participating in markets to guarantee asserted investment costs that have not been demonstrated to exist and should not be guaranteed, and to assume risks that should not be assumed, with no corresponding benefit whatsoever.

b. Mr. Pasternack's Logic Does Not Support Use of the AEP Method in Schedule 2 Proceedings.

There is no logical connection among Mr. Pasternack's three steps as stated in his 1993 testimony.[27] The first step is equivalent to a general statement that larger generators cost more. The first step uses MVA rating as a general, but approximate, metric for generator size. The exact nature of the proportional relationship is not specified. The second, and unrelated step, is a statement of the basic power triangle relationship among $(MVA)^2$, $(MW)^2$ and $(MVAR)^2$. The fact that the term MVA appears in both steps does not create a logical link.[28] The third step is not logically related to either of the prior two steps. No support was provided for the fundamental assertion/assumption that the ratio of $(MVAR)^2$ to $(MVA)^2$ is related to the costs of providing real and reactive power. No support is provided for the specific functional form, e.g. the specific relevance of $(1 - PF^2)$ rather than $(1 – PF)$. No support was provided for Mr. Pasternack's inextricably related assertion that the ratio of $(MVAR)^2$ to $(MVA)^2$ is a function of the nameplate power factor rather than the power factor identified in the Interconnection Service Agreement (ISA) and actually required.

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[26] Tr. at 3394:14–19.

[27] IMM-0008, Attachment: see also FER-0012.

[28] *Id*.

Mr. Pasternack's 1993 testimony made explicit that the allocator he proposed was based on subjective judgment.[29] Mr. Pasternack stated that it was fair and equitable to reassign a significant part of the capital costs of generators to transmission customers, including internal and external transmission customers, that had previously been assigned to power customers. Mr. Pasternack stated that his goal was "a fair and equitable cost-based charge to transmission users."[30] The Pasternack testimony was about reassigning costs that were already fully accounted for and not for any asserted costs to provide reactive power that were not recovered elsewhere and not for any asserted additional costs of providing reactive power.[31] Mr. Pasternack stated that generator costs had not been allocated to transmission customers by AEP prior to the case in which he proposed the allocation. Mr. Pasternack recognized that AEP was "breaking new ground in developing such a VAr charge."[32]

In his 1993 testimony, Mr. Pasternack was engaged in a cost allocation exercise designed to shift a significant level of generator costs from power customers to transmission customers.[33] Mr. Pasternack proposed the use of an allocation approach using one minus the power factor squared ($1 - PF^2$) where the PF was defined to be the nameplate power factor.[34] The reason for the allocation approach was to maximize the

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29 *Id*.

30 *See* FER-0012 at 9.

31 *Id*.

32 *See American Electric Power Service Corporation*, Supplemental Rebuttal Testimony of Bernard M. Pasternack, Docket No. ER93-540-000 (October 11, 1998) at 4 ("Pasternack Rebuttal Testimony").

33 *See* IMM-0008; FER–0012.

34 *Id*.

allocation of reactive costs to transmission customers rather than power customers.[35] The nameplate power factor is generally lower than the power factor required by the PJM Tariff.[36] A lower power factor means that the PF^2 is also lower and therefore that the allocator ($1 - PF^2$) is higher.[37] The differences in the allocator based on different power factors can be extreme.[38] For example, the allocation of costs to reactive using a nameplate power factor of 0.80 is 36 percent, while the allocation of costs to reactive using a power factor of 0.90 is 19 percent, and the allocation of costs to reactive using the required power factor of 0.95 is 10 percent.[39] If the choice is between allocating costs to reactive or power generation, it is not logical to use the largest reactive allocator rather than the largest generation allocator.[40] No good reason or any reason, for example based on assertions about cost or function, was provided by Mr. Pasternak for using the largest reactive allocator.[41] Mr. Pasternack never explicitly acknowledged the fact that his proposed allocation method maximized the allocation of unit investment costs to reactive.

In contrast to the Fern Solar case, Mr. Pasternack's cost allocation exercise was in a fully regulated cost of service environment where the regulated utility (AEP) for whom he was working had rates designed to allow recovery of 100 percent of all its costs.[42] In that environment, cost of service exercises were primarily about rate design; what set of

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35 *See* IMM-0008, Attachment.

36 *Id*.

37 *Id*.

38 *Id*.

39 *Id*.

40 *Id*.

41 *See id*.

42 *Id*.

customers should pay more or less.[43] In the Fern case, the reactive allocation discussion cannot be separated from the capacity market design.[44] The relationship between the capacity market and reactive revenue is recognized in the PJM market rules.[45] The capacity market explicitly accounts for reactive revenue in the energy and ancillary services offset in defining the capacity market demand curve (VRR curve).[46]

The attempt to maximize the allocation of costs to reactive is inconsistent with the design and functioning of the capacity market. The capacity market includes all the costs of capacity.[47] Critically for the allocation question, when capacity resources sell capacity, they attempt to maximize the amount of capacity in MW of installed capacity (ICAP) that they offer in the capacity market, net of the forced outage rate (UCAP).[48] The ICAP amount is based on tests. Capacity resources are required to offer energy equal to the full ICAP every day in the energy market.[49] Holding aside the more fundamental issue with any positive cost of service payment for reactive, it is not logically consistent to include a reactive allocation factor based on a power factor that assumes power production at less than this full ICAP level, which defines the obligation of the generator to provide real power in MW.[50] That choice, to include a reactive allocation factor that assumes power production at less than ICAP, despite the obligation of resources to offer full ICAP in the energy market every day, is never supported. If done correctly, the allocation of costs to

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43 *Id*.

44 *Id*.

45 *Id*.

46 *Id*.

47 *Id*.

48 *Id*.

49 *Id*.

50 *Id*.

reactive would be zero. The conclusion is that the *AEP* Method is fundamentally inconsistent with the design of the capacity market and the obligations of resources to provide energy.

Cost allocation studies require the creation of allocation factors.[51] Once the judgment has been made to allocate costs, cost allocation studies require that there is some way, regardless of its rationale, to assign costs to customer classes.[52] That is not true in markets.[53] Mr. Bethel, in his uncritical acceptance of Mr. Pasternack's allocation approach, would ignore the underlying reality of the cost of service reactive allocation factors applied in a market environment.[54] The actual impact is that, in PJM markets, the larger the reactive allocation, the larger the guaranteed, non market revenues received and the less the generator has to rely on markets.[55] The effective function of the proposed reactive allocation approach is to assign risk to customers and away from investors. This is exactly contrary to market principles.[56] In a market, the generation owner is not guaranteed any level of cost recovery.[57] In a market, the concept of cost recovery is not relevant. Investors invest with the expectation of earning a target rate of return from markets, with the associated uncertainty.[58] When PJM introduced markets to replace cost of service regulation, all of the capital costs of generation were included in the PJM

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[51] *Id*.

[52] *Id*.

[53] *Id*.

[54] *Id*.: *see* FER-0001.

[55] *Id*.

[56] *Id*.

[57] *Id*.

[58] *Id*.

markets and no longer subject to cost of service regulation.[59] Mr. Pasternack's approach, which was incorrect even at the time he proposed it, does not apply in markets like the PJM markets.[60]

Reactive power is an ancillary service. It is ancillary to the provision of energy and capacity. It is not intended to supplant or exceed the role of the capacity market.[61] Yet that is exactly the implication of the approach supported by Mr. Bethel.[62] The results of the application of the proposed allocation method, including the proposed use of the nameplate power factor, also demonstrate the unreasonable nature of the approach.[63] The nameplate power factor is the power factor at the generator terminals and not the power factor actually provided to the transmission system and not the power factor required by PJM.[64] Mr. Bethel proposes that PJM customers pay more for reactive power from the Fern Facility than the capacity market clearing price in PJM markets.[65] This absurd result demonstrates the practical effect of applying the illogical and unsupported reactive allocation approach to the Fern Facility.[66] The results are particularly disproportionate for inverter based resources like Fern Solar.[67]

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[59] *Id*.

[60] *Id*.

[61] *Id*.

[62] *Id*.; *see* FER-0001.

[63] *Id*.

[64] *Id*.

[65] *Id*.; see FER-0001.

[66] *Id*.

[67] *Id*.

The basic math referenced repeatedly in the discussions of reactive allocators is straightforward.[68] The basic math is presented in equation format and all in one place for purposes of clarification:

(1) $MVA^2 = MW^2 + MVAR^2$

(2) $1 = \frac{MW^2}{MVA^2} + \frac{MVAR^2}{MVA^2}$

(3) $\left(1 - \frac{MW^2}{MVA^2}\right) = \frac{MVAR^2}{MVA^2}$

(4) $PF = \frac{MW}{MVA}$

(5) $(1 - PF) = \frac{MVAR}{MVA}$

(6) $PF^2 = \frac{MW^2}{MVA^2}$

(7) $(1 - PF^2) = \frac{MVAR^2}{MVA^2}$

Defined terms:

MVA: Apparent power in megavolt amperes

MW: Real power in megawatts

MVAR: Reactive power in megavolt amperes reactive

PF: Power factor[69]

Equation (1) is the referred to as the power triangle relationship. Equation (2) is equation (1) after both sides are divided by MVA^2. Equation (3) subtracts the term (MW^2/MVA^2) from both sides of equation (2). Equation (4) is the definition of the power factor (PF), MW divided by MVA. Equation (5) is (1 – PF), MVAR divided by MVA.

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68 *Id*.

69 *Id*.

Equation (6) is the PF squared, from equation (4). Equation (7) combines equation (3) and equation (6), showing that $(1 - PF^2)$ equals $MVAR^2$ divided by MVA^2. Equation (7), using a nameplate PF value, is the allocation approach used by Mr. Pasternack and Mr. Bethel to assign generation costs to reactive.

In summary, the equations are based on the definition of the power triangle and the definition of the power factor.[70] The rest is just rearranging terms following the rules of algebra.[71] There is no relationship between the power triangle equation or the definition of the PF, and the costs of providing reactive power. These equations do not create or support such a relationship.[72]

This set of equations is the basis for the reactive allocation approach used by Mr. Pasternack.[73] The equations provide a bit more clarity to the relationships identified by Mr. Pasternack but do nothing to change the fact that there is no logical relationship among the three steps listed by Mr. Pasternack as the rationale for his use of $(1 - PF^2)$ as the basis for allocating a significant share of the costs of generating units to reactive power.[74] There is also no basis in these equations for the use of a nameplate PF which significantly increases the claimed allocation of costs to reactive.[75]

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[70] *Id*.

[71] *Id*.

[72] *Id*.

[73] *Id*.

[74] *Id*.

[75] *Id*.

2. The Difficulty: Applying a 1999 Coal Decision to a 2020 Solar Facility.

a. The AEP Method Is Not Appropriate for PJM Schedule 2 Proceedings.

The *AEP* Method was developed and filed in 1993. The *AEP* Method was developed to address issues in the context of the electric industry as it was structured in 1993. The *AEP* Method has been applied without explanation in PJM competitive markets even though it originated prior to the PJM development of PJM Capacity Market (2006), prior to the development of any PJM competitive markets (1999) and prior to the electric industry restructuring begun in Order No. 888, et seq. (1996).

Dr. Bowring summarized at hearing the mismatch between AEP's situation in 1993 and PJM markets today:

> [T]he problem with this entire exercise, and the Pasternack assertions from the very beginning, because what he was doing was assigning costs between two sets of customers, both of whom guaranteed payment of 100 percent of whatever they are allocated. And that's not what's happening here. What's happening is we are dividing revenues between markets and non-markets. And the fact is that the power factor approach is designed, at least as it's proposed by Fern, to maximize the amount of revenues assigned to the risk-free cost-of-service recovery, rather than markets.[76]

Even in the context of AEP in 1993, the *AEP* Method had only superficial appeal. The *AEP* Method did not then and does not now actually provide a sound logical basis for cost allocation.

In this case, indifference to the consequences of the using the *AEP* Method is not just and reasonable. Use of the *AEP* Method has harmful impacts on policy, fairness and

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76 Tr. at 3404:3-13.

efficiency. A logical evaluation of the *AEP* Method reveals that it does not support a revenue requirement under Schedule 2.

b. The AEP Method Should Not Be Used for Solar Facilities.

Fern fails to demonstrate that application of the *AEP* Method is appropriate for its asynchronous solar Fern Facility. The *AEP* Method was developed for use with a fleet that consisted primarily of steam plants.[77] No decision has determined that the *AEP* Method should apply to asynchronous solar facilities. The Commission has identified the issue, and it is under consideration in a pending rulemaking proceeding.[78] *Panda Stonewall*, a recent case involving the *AEP* Method, explicitly limits its holding on the appropriate power factor to synchronous facilities.[79]

Fern Witness Dennis Bethel provides testimony attempting to demonstrate how the *AEP* Method can be applied to a solar facility like the Fern Facility.[80] Witness Bethel does not explain how the *AEP* Method produces an accurate cost-based revenue requirement for reactive supply capability for an asynchronous resource, or for any type

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77 NOI at P 17 ("[T]he AEP Methodology was designed based on the physical attributes of synchronous resources owned by a public utility that utilized the USofA and annually submitted a FERC Form No. 1.").

78 *See id*. at P 28, question j ("Is the existing AEP Methodology appropriate to allocate the costs associated with reactive power revenue requirements of non-synchronous resources? If not, why and can changes be made to the existing AEP Methodology to establish just and reasonable reactive power revenue requirements for non-synchronous resources? If so, please provide detailed descriptions of any potential changes and explain why they are necessary.").

79 *See* FER-0055 (*Panda Stonewall LLC*, Opinion No. 574, 174 FERC ¶ 61,266 at P 109 (2021) ("For these reasons, we affirm the Initial Decision's finding that Panda's reactive power capability should be based upon a power factor of 0.85 since the facility is a new synchronous generator facility and degradation of its reactive power output is not an issue.")).

80 *See* FER-0001 at 29:10–30:2.

of resource. Identifying the *AEP* Method's formula and drawing analogies between equipment at synchronous facilities and asynchronous facilities does not substitute for the core showing required, that the *AEP* Method identifies the incremental costs for providing reactive supply capability.[81]

Issues about the application of the *AEP* Method to solar photovoltaic facilities are issues of first impression, and if these issues are decided in this proceeding, they should be resolved based on the record in this proceeding and without consideration of inapplicable prior precedent.

3. The NOI and the NOPR.

There is really only one reason why Fern's revenue requirement may be approved in this proceeding despite the complete lack of any reasonable evidence in support of it. That reason is inertia.

As Dr. Bowring explained, in response to the Presiding Judge's question about how the deeply flawed administration of Schedule 2 could be so wrong for so long:

> So I agree that the regulatory process exhibits and this is a particular case of, a great inertia. And the AEP method was devised before we moved to markets, and it really didn't receive much attention. It's only received attention recently as the amount of money got larger and larger. There is more than $370 million in PJM reactive, so it has gotten people's attention. So … there has been a lot of inertia in the regulatory process.[82]

The Commission has allowed reactive revenue requirements to become effective in PJM for many years. The few cases that resulted in precedential decisions never considered the fundamental issues about how Schedule 2 filings should be evaluated. They do not explain what reactive supply capability compensable under Schedule 2 is.

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[81] *See id*. at 31:3–32:4.

[82] Tr. at 3395:10–18.

They do not explain what the *AEP* Method is and how or whether it produces it a just and reasonable rate. They do not explain how Schedule 2 rates exist within the PJM market design and how over recovery is avoided. In this case, the issues are squarely raised, and they deserve to be squarely decided.

The Commission recognized the serious policy problems related to reactive power compensation in a workshop convened June 30, 2016, and in a notice of inquiry issued in RM22-2 (“NOI”).[83] In the NOI, the Commission issued questions that reveal that the Commission is concerned about issues raised by the Market Monitor concerning compensation for reactive supply capability, including the issues raised in this proceeding.

The issues raised in the NOI include:

- Whether cost of service compensation is appropriate for reactive supply compensation.[84]
- Whether the *AEP* Method is a just and reasonable for the development of reactive supply capability rate.[85]
- Whether Schedule 2 rates that exceed the $2,199 offset included in the design parameters of PJM capacity markets result in impermissible double recovery.[86]

While the NOI remains pending, the Commission has approved MISO’s elimination from its market rules MISO’s equivalent to Schedule 2 revenue requirements,

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83 *Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, AD16-17-000; *See Reactive Power Capability Compensation*, Notice of Inquiry, 177 FERC ¶ 61,118 (2021) (“NOI”).

84 NOI at P 26.

85 NOI at P 28, questions a–q.

86 NOI at PP 27 & 28, questions r and s.

aligning MISO with CAISO and SPP, which never adopted the defective approach.[87] The Commission's finding was broad, and addressed and rejected many of the arguments made by Fern in this case.

The Market Monitor is an active participant in a PJM stakeholder group, the Reactive Power Compensation Task Force ("RPCTF") that is considering reforms to the PJM market rules. In that process, the Market Monitor has advocated the MISO/CAISO/SPP approach. PJM stakeholders have not reached agreement or approved a filing under FPA Section 205, and PJM has not made a filing.[88]

There is no reason to wait for Commission action on the pending rulemaking or for a PJM Section 205 filing in order to decide the fundamental issues on the merits. Schedule 2 does not authorize PJM to bill Schedule 2 revenue requirements unless they are accepted or approved by the Commission. Fern's proposed revenue requirement should not be approved and the amounts collected since it was accepted should be refunded. Schedule 2 does not limit the Presiding Judge's resolution of the issues presented by Fern's Schedule 2 filing. Nothing prevents the Presiding Judge from rejecting Fern's unsupported rate for reactive supply capability. Nothing prevents the Presiding Judge from rejecting the use of the *AEP* Method based on reasoned analysis of what the *AEP* Method actually is and is not, and how it actually operates. Nothing prevents the Presiding Judge from preventing an over recovery of funds from PJM customers in light of the $2,199 per MW-Year that is as much a part of the PJM Market Rules as is Schedule 2.

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87 182 FERC ¶ 61,033.

88 PJM has the independent authority to submit filings that change rules included in the OATT, including the affected provisions Schedule 2 and Attachment DD.

III. ARGUMENT: THE INDEPENDENT MARKET MONITOR'S OPPOSITION.

A. Fern Has Not Shown that It Is Entitled to Receive Compensation under Schedule 2.

Fern asserts that its proposed reactive rate (ARR) is calculated using the *AEP* Method. Fern asserts that in applying the *AEP* Method, it identifies costs associated with four groups of plant investment: (1) the generators/exciters; (2) generator step-up transformers; (3) accessory electric equipment; and (4) the remaining production plant investment; and then allocates those costs between real and reactive power using an allocation factor. Witness Horigan claims that it used the *AEP* Method to "isolate the costs incurred by a facility related to the provision of reactive power, through various cost identification and allocation factors."[89] Fern fails to show how it has identified any costs related to the provision of reactive power using the *AEP* Method. Fern fails to explain how the *AEP* Method performs this function.

Fern does not and cannot demonstrate any specific costs associated with providing reactive supply capability that are not recoverable in PJM markets through the sale of energy, ancillary services, or capacity. There are no such costs.

Schedule 2 provides for the recovery of a revenue requirement.[90] Schedule 2 does not define that revenue requirement or how it should be calculated.[91] Schedule 2 does not create a right to recover any cost already recovered or recoverable under the PJM market

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89 FER-0004 at 2:19–21.

90 *See* IMM-0002 ("Each month, the Transmission Provider shall pay each Generation Owner or other source owner an amount equal to the Generation Owner's or other source owner's monthly revenue requirement as accepted or approved by the Commission.").

91 *Id*.

rules.[92] Schedule 2 does not provide for the allocation of costs between a cost of service generation facilities account and a transmission facilities account.[93] Schedule 2 does not reference the *AEP* Method or any method.[94]

1. A. Real Costs and Reactive Costs Are Inseparable.

The PJM market design allows for the competitive investment in generation resources, including their ability to produce real and reactive power. At the same time, Schedule 2 provides for the recovery of a "revenue requirement" associated with the provision of reactive. Generating facilities use the same equipment to sell real power and capacity in markets and to provide reactive supply capability and this fact creates the potential for over recovery.

Fern fails to acknowledge the fact that any costs allocated to the provision reactive supply capability reduce the costs allocated to the provision of real power supply capability. Fern never explains why maximizing the allocation of costs to reactive and therefore minimizing the allocation of costs to the generation of energy is reasonable. It is not reasonable.

2. Power Factor Is Irrelevant to Cost Allocation.

In his testimony, Market Monitor Witness Bowring explains why the *AEP* Method and the misplaced reliance of that method on the power factor squared are not suitable for developing a cost-based revenue requirement under Schedule 2.[95]

The *AEP* Method assigns costs between real and reactive power based on a unit's power factor.[96] This is effectively an allocation based on a subjective judgment rather

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92 *Id*.

93 *Id*.

94 *Id*.

95 IMM-0001.

96 *Id*. at 6:7–8.

than actual investment.[97] There are few if any identifiable costs incurred by generators in order to provide reactive power.[98] Separately compensating resources based on a judgment based allocation of total capital costs was never and is not now appropriate in the PJM markets.[99] Generating units are fully integrated power plants that produce both the real and reactive power required for grid operation.[100]

The *AEP* Method originated with a regulated utility assigning costs between two sources of regulated revenue requirement.[101] The practice persists in PJM only because it provides a significant, guaranteed stream of riskless revenue. Generation owners have an incentive to maximize such guaranteed revenue streams.[102]

There is no logical reason to have a separate fixed payment for any part of the capacity costs of generating units in PJM.[103] If separate cost of service rates for reactive continue, they need to reflect no more than the level of reactive revenue offset assumed in the PJM market design.[104]

The best and straightforward solution is to remove cost of service rates for reactive supply capability and to remove the offset.[105] Investment in generation can and should be

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[97] *Id*. at 6:8–9.

[98] *Id*. at 6:9–11.

[99] *Id*. at 6:11–12.

[100] *Id*. at 6:13–14.

[101] *Id*. at 6:15–16.

[102] *Id*. at 6:17–18.

[103] *Id*. at 6:19–20.

[104] *Id*. at 6:20–21.

[105] *Id*. at 6:22–23.

compensated entirely through markets.[106] Removing cost of service rules would avoid the significant waste of resources incurred to develop unneeded cost of service rates.[107]

The result would be to pay generators market based rates for both real and reactive capacity.[108]

The *AEP* Method never accurately reflected the investment costs of providing reactive power, nor was it intended to do so.[109] The *AEP* Method is a cost of service allocation approach designed to assign the regulated revenue requirement for generating units to a regulated generation function and a regulated transmission function.[110] The *AEP* Method was designed to split that cost recovery for generating units in a reasonable way, based on a judgment about what is reasonable.[111] The *AEP* Method was never about actually identifying specific capital costs associated solely with the provision of reactive power.[112] Cost of service approaches apply allocation factors to accounting line items based on assumptions.[113] The assumptions are that X percent of a type of equipment at a generating plant is associated with reactive power while (1-X) percent is associated with real power.[114] The false precision of the *AEP* Method is entirely based on arbitrary

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106 *Id*. at 6:23–24.

107 *Id*. at 6:24–26.

108 *Id*. at 6:27–28.

109 *Id*. at 6:29–30.

110 *Id*. at 6:30–7:2.

111 *Id*. at 7:2–3.

112 *Id*. at 7:3–5.

113 *Id*. at 7:5–6.

114 *Id*. at 7:6–8.

assumptions.[115] Even proponents of the *AEP* Method do not assert that the goal is to recover only the costs associated with a specific portion of a power plant required for the production of reactive power, or, in most cases, that such identification is even possible.[116] That is not what the *AEP* Method was intended to do or is intended to do.[117] The *AEP* Method does not define costs that are uniquely associated with the production of reactive power.[118]

The *AEP* Method is based on the incorrect premise that the capacity costs of an integrated power plant are separable. The capacity costs of an integrated power plant are not separable.[119]

The fundamental flaw in the *AEP* Method approach is the assumption that the costs of providing reactive power are a function of the power factor.[120] The power factor is the ratio of real power (expressed as megawatts or MW) to the total output (apparent power) of a generator (expressed as megavolt-amperes or MVA).[121] The remaining output is reactive power (expressed as megavolt amperes reactive or MVAR). The allocator typically used by proponents of the *AEP* Method to assign costs to reactive power generation is $(1 - (\text{PowerFactor})^2)$.[122] The power factor has superficial attraction as an appropriate allocator.[123] The power factor is the core determinant of the reactive

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115 *Id*. at 7:8–9.

116 *Id*. at 7:9–12.

117 *Id*. at 7:12–13.

118 *Id*. at 7:13–14.

119 *Id*. at 7:15–17.

120 *Id*. at 7:18–19.

121 *Id*. at 7:19–21.

122 *Id*. at 7:22–24.

123 *Id*. at 7:24–25.

allocation factor in the *AEP* Method. Small changes in the power factor have large impacts on the costs allocated to reactive power.[124] For a power factor of .95, the allocator is 9.75 percent while for a power factor of .90, the allocator is 19.00 percent, and for a power factor of .70, the allocator is 51.00 percent.[125] A resource claiming a power factor of .70 does not incur more than half of its costs in order to provide reactive power.[126] Therefore fifty-one percent of the costs of the generator, exciter, and electrical equipment should not be recovered through a cost of service rate.[127] But resources have filed for guaranteed reactive revenue requirements on that basis.[128] The assertion that more than half of the identified generator costs should be recovered through a rate for an ancillary service is effectively a *reductio ad absurdum* demonstration.

The power factor has taken on somewhat mythical significance in the discussion of reactive power. There are frequently long discussions of power factors in reactive cases.[129] The ratio of real to reactive power can vary significantly. The typical actual operating power factor of generators in PJM is determined by their voltage schedule and is usually between .97 and .99.[130] The resultant *AEP* Method power factor allocator consistent with this actual reactive output of PJM generators and the actual tariff defined reactive output to generators is 5.91 to 1.99 percent.[131] The nameplate power factor of

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124 *Id*. at 7:26–27.

125 *Id*. at 7:27–29.

126 *Id*. at 7:29–31.

127 *Id*. at 7:31–32.

128 *See Meyersdale Storage, LLC*, Protest of the Independent Market Monitor for PJM, Docket No. ER21-864-000 (February 2, 2001) at 2.

129 *See, e.g.*, FER-0055 (*Panda Stonewall LLC*, f174 FERC ¶ 61,266 (2021)).

130 IMM-0001 at 6:3–5.

131 *Id*. at 8:5–7.

thermal generating units is typically .85.[132] But the nameplate power factor stamped on the generator at the factory and not based on actual operation on an actual grid.[133] The nameplate power factor is meaningless for the actual operation of the power plant.[134] The nameplate power factor does not mean that 27.75 percent of the power plant capital costs are associated with reactive power, although many resources have made that request because that is the power factor allocator based on the nameplate rating.[135]

The power factor is not an appropriate allocator and does not reflect the actual capital costs associated with producing reactive power.[136] The power factor has taken on a disproportionate significance in reactive rate cases because it is the single most important allocator in the *AEP* Method.[137] That significance illustrates the fundamental flaws in the *AEP* Method.[138]

The power factor does not measure reactive capability.[139] The power factor does not determine a plant's reactive capability.[140] The power factor does not identify costs associated with reactive capability or provide a reasonable basis for allocating those costs to reactive or real power production.[141]

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[132] *Id*. at 8:7–8.

[133] *Id*. at 8:8–10.

[134] *Id*. at 8:10–11.

[135] *Id*. at 8:11–14.

[136] *Id*. at 8:15-16.

[137] *Id*. at 8:16–18.

[138] *Id*. at 8:18–19.

[139] *Id*. at 8:20.

[140] *Id*. at 8:20–21.

[141] *Id*. at 8:21–23.

3. Compensation for Reactive Power Capability Should Occur Via Real Power Sales Only.

The Market Monitor's position is that reactive revenue requirements for generation resources providing reactive supply capability under Schedule 2 should be eliminated. Reactive revenue requirements should be eliminated in PJM for the same reason that they were eliminated in MISO, and are not included in the CAISO and SPP rules.[142]

Unlike the MISO, CAISO and SPP rules, the PJM rules recognize under Schedule 2 that a resource may file to receive revenue requirement with the Commission.

Schedule 2 recognizes that a resource may file a revenue requirement and how such a revenue requirement would be billed to PJM customer if accepted or approved. Schedule 2 says nothing about what is required for acceptance or approval. Schedule 2 does not specific any rate or revenue requirement. Schedule 2 does not require PJM or PJM customers to pay any revenue requirement. PJM customers are only required to pay a revenue requirement under Schedule 2 unless and until it is "accepted or approved" by the Commission.

The scope of this case is now limited to the whether a proposed revenue requirement file under Schedule 2 should be approved. This case does not provide an opportunity to revise the PJM market rules to eliminate Schedule 2. A rate of zero dollars is appropriate in this case because the record in this case does not support a higher revenue requirement.

The answer must be zero dollars for the same reasons that the Commission has eliminated the reactive supply capability rate inMISO, and approved the CAISO and SPP tariffs excluding such payment.

Fern's filed revenue requirement should be found unjust and unreasonable, and terminated subject to refund.

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142 *See, e.g.*, 182 FERC ¶ 61,033.

B. Any Cost Based Compensation Should Not Exceed $2,199/MW Year.

If a rate exceeding zero dollars is approved in this proceeding, over recovery must be avoided.[143] The Commission has recognized the issue of over recovery specifically in the context of the application of Schedule 2.[144]

While the *AEP* Method does not actually identify the costs of providing reactive supply capability, it is designed to split without overlap the costs of a coal plant between generation and transmission accounts.[145] In AEP, such a split was not a problem because

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143 *See, e.g.*, United Airlines, Inc. v. FERC, 827 F.3d 122, 134 (D.C. Cir. 2016) ("[B]ecause FERC failed to demonstrate that there is no double-recovery . . . we hold that FERC acted arbitrarily or capriciously.").

144 *See* NOI at PP 18, 26, 27, 28(j) and 28(s) (summarizing the IMM's arguments and asking "Is the existing AEP Methodology appropriate to allocate the costs associated with reactive power revenue requirements of non-synchronous resources? If not, why and can changes be made to the existing AEP Methodology to establish just and reasonable reactive power revenue requirements for non-synchronous resources?" and "Do resources in PJM that receive reactive power capability compensation above $2,199/MW-year effectively receive double-recovery as alleged by the PJM Market Monitor?").

145 *See AEP* at 61,456 ("AEP explained that since generator/exciters and an allocated portion of accessory electric equipment produce active and reactive power, "it was necessary to arrive at an allocation factor to segregate the reactive (VAr) production function from the active power (Watt) production function."); *see also Fern Solar LLC*, Order Denying Motion for Partial Summary Disposition and Motion to Strike, 180 FERC ¶ 63,024 at P 15 (2022) ("The AEP method came into being because one of its creators, AEP's Bernard Pasternack, needed to allocate costs between two cost-based services, generation and transmission. AEP's utility subsidiaries were unbundling regulated transmission service from regulated generation service, making each service available for sale separately. Since each of these regulated services would need its own cost-of-service rate, Mr. Pasternack faced a classic cost allocation problem—how to determine which pieces of equipment serve a transmission function and which serve a generation function; and where some pieces of equipment served both functions, how to allocate their costs between the two functions. But because the price-basis for both services was traditional cost of

in AEP there was an allocation to two cost of service accounts. In the PJM market design, a dollar allocated for recovery under Schedule is a dollar that is already recoverable in PJM's competitive markets. In PJM, a dollar recoverable through markets is not appropriately included in a revenue requirement for reactive supply capability.

The only amount of investment that could be determined not recoverable through markets is an explicit offset, fixed at $2,199 per MW-Year that accounts for revenues resources are expected to receive under Schedule 2. The offset is the only valid basis for resources to receive a revenue requirement under Schedule 2. Fern has not requested a revenue requirement under Schedule 2 based on the offset.

To the extent that Fern Facility receives a revenue requirement exceeding $2,199 per MW-Year, it receives an impermissible over recovery.[146] The Fern Facility's revenue requirement should be capped at $2,199 per MW-Year.

Witness Bowring provides testimony explaining that the PJM market design explicitly accounts for and excludes from the capacity market design $2,199 per MW-Year in order to account for revenues received under Schedule 2.[147] The rules that account for recovery of reactive revenues are built into the auction parameters, specifically, the VRR curve. The PJM market rules explicitly account for recovery of reactive revenues of $2,199 per MW-year through inclusion in the Net CONE parameter

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service set by the same regulatory jurisdiction, there was no possibility of duplicative recovery.").

146 *See* 180 FERC ¶ 63,024 at P 17 ("The PJM capacity market design does aim to prevent duplicative recovery. It does so through its Variable Resource Requirement (VRR) curve, which has a reactive power "offset"; specifically, a leftward shift to reflect PJM's assumption that each reactive providing generator will recover $2,199/MW-year through cost-based compensation. But the offset works to prevent overcompensation only if the cost-based price stays below $2,199/MW-year.").

147 *See* IMM -0001 at 4:6–5:16.

of the capacity market demand (VRR) curve.[148] The Net CONE parameter directly affects clearing prices by affecting both the maximum capacity price and the location of the downward sloping part of the VRR curve. In addition, market sellers, when submitting offers based on net avoidable costs must account for revenues received through cost of service reactive capability rates in the calculation.[149] The $2,199 per MW-Year value happens to be close to the average revenues received by resources in PJM for reactive supply capability.[150]

IV. ARGUMENT: FIXED CHARGE RATE

A. Fern Fails to Justify Its Approach to Calculating Its Capital Recovery Rate, and It Should Be Found Unjust and Unreasonable.

If the *AEP* Method were applied to any resource for establishing a cost-based revenue requirement under Schedule 2, it is important to establish an accurate and consistent method for calculating the capital recovery factor ("CRF"). The CRF is a rate, multiplied by the relevant investment, which defines the annual payment needed to provide a return on and of capital for the investment over a defined time period. CRFs include as inputs the weighted average cost of capital and its components, including the rate of return on equity and the interest rate on debt and the capital structure, in addition to depreciation and taxes.[151] The CRF approach is a standard approach to calculating the revenue requirement associated with any investment over a defined time period.

Fern's proposed method for calculation of its form of CRF, which it refers to as the "fixed charge rate," results in an excessive value that inflates its proposed revenue

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148 *See* OATT Attachment DD § 5.10(a)(v)(A).

149 OATT Attachment DD § 6.8(d).

150 *See* IMM-0001 at 3:24–4:1.

151 *See* IMM-0001 at 9:9–11.

requirement.[152] The Market Monitor objects to the calculation of a cost of service revenue requirement in this proceeding, but if such an approach is used, then an accurate calculation of the CRF component should be required.

The CRF currently sponsored by Fern is in the prepared answering testimony of W. Wade Horigan submitted on August 30, 2022.[153] Witness Horigan updates the CRF originally sponsored by Fern and presented in the prepared direct testimony of Donald J. Clayton filed on June 26, 2020.[154]

Witnesses Horigan and Clayton derive a fixed charge rate which is the sum of a CRF component and a fixed operating expense rate. The CRF presented by Witness Horigan is the sum of a sinking fund depreciation factor and the before tax weighted average cost of capital. Witness Horigan's updated derivation removed the income tax factor and accumulated deferred income tax offset that was included in Witness Clayton's original derivation.[155]

The Market Monitor's Witness, Dr. Joseph Bowring, in his testimony filed June 15, 2022 (IMM-0001), reviewed Witness Clayton's testimony and concluded: "The derivation does not accurately reflect the tax liability or the return on and the return of the capital investment."[156] Specifically, Dr. Bowring stated: "Witness Clayton did not account for the actual tax treatment of the facility and did not adequately explain his tax treatment, did not account for the actual expected life of the facility, did not adequately

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152 *See* FER-0004 at 40:27–49:14.

153 *See* FER-0004.

154 *See* FER-0004 at 3:1–7; FS-1 at 19–21.

155 *See* FER-0004 at 49:10–12.

156 *See* IMM-0001 at 9:4–6.

explain or support his depreciation method, and did not account for the actual cost of capital of the facility."[157]

The Fern facility achieved commercial operation in December 2020 and would have been eligible for an investment tax credit (ITC). Fern objected to the Market Monitor using the ITC as an offset to the capital investment prior to multiplication by the CRF. Witnesses Horigan and Gulley claim that the impact of the ITC should be reflected as a reduction in the cost of capital. However, the cost of capital used in the Fern calculation is the Dominion cost of capital, and therefore Horigan and Gulley did not make their referenced reduction to the cost of capital. Horigan asserts, without support, that Fern's actual cost of capital would have been higher than the Dominion cost of capital. This highlights a principal problem with Fern's request in that the proposed calculation does not reflect, or attempt to reflect, the actual tax and financial structure of the project. The Market Monitor's CRF is a superior approach, based on the actual tax and financial structure, and Fern has never explained why the Market Monitor's treatment of the ITC is not appropriate. Witness Gulley notes that the "ITC unlocks access to capital that is otherwise unavailable for financing renewable energy assets."[158] Gulley also points out that in "a typical tax equity partnership, the developer and the investor will make equity contributions, which are used to acquire the project assets and then factor the value of the tax benefits such as the ITC into their allocation of rights."[159] The ITC enables the developer to swap tax credits which can only be monetized after production begins, for capital to finance the project. Thus the ITC reduces the capital requirement as reflected in the Market Monitor's calculation. The capital attained through the tax equity partnership that is to be recovered through the ITC should be used to offset

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[157] *Id*. at 9:17–20.

[158] *See* FER-0013 at 9:5–6.

[159] *Id*. at 17:11-14.

the capital requirement. Any portion of the capital obtained through the tax equity partnership that is to be recovered through the revenue requirement should be treated as equity. The Market Monitor's calculation is consistent with this treatment.

Fern fails to show that its proposed CRF is just and reasonable. If a cost of service rate were approved, Fern's proposed CRF should be replaced with the CRF calculated by the Market Monitor.

B. The Market Monitor's Proposed CRF Is Just and Reasonable.

The Market Monitor proposes an alternative method for calculating the CRF, defined in a technical reference ("CRF Technical Reference").[160] The CRF Technical Reference explains in detail the how to accurately and consistently calculate a CRF. The CRF Technical Reference is designed for, and should be required for use in, all cost based revenue requirement provisions used in PJM, which now include black start service rates and reactive capability rates.[161] The Commission accepted the approach included in the CRF Technical Reference for black start service and directed PJM to include the CRF formula in the PJM tariff.[162] Consistent use of the CRF would ensure that accurate, just, reasonable and nondiscriminatory values are applied. Accurate and consistent values promote efficient markets and just and reasonable, competition based rates.

Witness Bowring explains:

> The CRF as proposed by the Market Monitor provides the necessary and sufficient level of revenue to pay the annual tax liability and the return on and return of the capital investment. The CRF approach proposed by the Market Monitor is based on the weighted average cost of capital (WACC) capital

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160 *Id*. at 8:21–11:24; IMM-0003 (Capital Recovery Factor (CRF) Technical Reference); IMM-0004 (CRF and Annual Payment–Capital Reduced for ITC) and IMM-0005 (CRF and Annual Payment-not reduced for ITC).

161 *Id*. at 9:28–29.

162 *PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,080 at PP 43–44 (2021).

> budgeting method. Under the WACC approach, the after tax cash flow is discounted at the after tax WACC rate and the payback of the investment in each cost recovery year reflects the defined capital structure. This approach can be efficiently reduced to a single formula for the CRF.[163]

The Market Monitor used the CRF approach to determine an annual revenue requirement based on the capital cost data and financing structure provided in the Horigan Testimony.

The Market Monitor provides the results in Exhibit Nos. IMM-0004 and IMM-0005.[164] Exhibits Nos. IMM-0004 and IMM-0005 illustrate the implications of the issues with the company's CRF calculations for the annual revenue requirement, assuming the company's allocation of costs to reactive are correct. The Market Monitor does not advocate using the annual revenue requirements in Exhibits Nos. IMM-0004 and IMM-0005, but includes the calculations solely for the purpose of showing the implications of the incorrect CRF calculations proposed by Fern.

For a 25 year cost recovery period, the Market Monitor's CRF is 0.085862 and the corresponding annual revenue payment is $860,321.[165] The formula for the CRF is equation (1.4) in the CRF Technical Reference.[166] The calculation assumes the half year convention for the timing of revenue and tax payments. This value reflects the capital cost recovery and does not include fixed operating expenses in order to protect Fern's confidential information.

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163 *See* IMM-0001 at 10:1–11.

164 The capital cost values in Exhibits Nos. IMM-0004 and IMM-0005 are from the Clayton Testimony (Exh FS-3). The amount was later revised by Witness Horigan (FER-0006).

165 *See id*. at 10:15–17.

166 *See id*. at 10 n.10.

The Market Monitor's CRF is lower than the CRF proposed by Witness Horigan. The Market Monitor's annual revenue requirement in IMM-0004 reflects a reduction to the reactive capital cost to account for an investment tax credit (ITC). Fern's filed rate inappropriately fails to reflect ITCs.[167]

Witness Horigan's inexplicably asserts that the manner in which the ITC is used or accounted for by the recipient of the tax credit is not relevant to the calculation of the capital recovery payments to the recipient.[168] It is clear, of course, that the ITC is relevant.[169] Whether it is a direct offset to the tax liability or a payment or series of payments from third party tax equity financing, the capital cost is reduced.[170] As Dr. Bowring explains, reducing capital costs is the reason for the ITC mechanism: "[The ITC] provides an incentive to the project by reducing the cost."[171] Dr. Bowring explains the distortion what would result from accepting Witness Horigan's view: "If recovery of the value of the ITC in a capital recovery payment is allowed, as suggested by Witness Horigan, the incentive would be doubled."[172]

The Market Monitor's payment is lower than the payment proposed by Witness Horigan. The Market Monitor's CRF calculations in Exhibits Nos. IMM-0004 and IMM-0005 reflect the 100 percent bonus depreciation provisions of the tax code that allow generators placed in service after September 27, 2017, to fully depreciate the capital investment in the first year of operation.[173] Fern's failure to use the 100 bonus

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167 *See* S-0013 at 29:3–31:20.

168 *See* FER-0004 at 41:7–10.

169 *See* IMM-0007 at 6:27–7:2.

170 *See id*.

171 *See id*. at 6:31–32.

172 *See id*. at 6:32–7:2.

173 *See* IMM-0001 at 11:1–3.

depreciation in their calculations also results in an overstatement of their calculated revenue requirement. In order to provide information in this matter, Exhibit No. IMM-0005 shows the Market Monitor's proposed capital cost recovery assuming no reduction for an ITC.

Exhibit Nos. IMM-0004 and IMM-0005 also show the CRFs and corresponding capital recovery payments for recovery periods exceeding 25 years. For example, the Market Monitor's CRF for a 40 year cost recovery period is 0.075600.[174] The corresponding annual payment is $257,172 under the assumption that the reduction of the reactive capital cost by an ITC is applicable.

Neither Witness Clayton nor Horigan has explained why a 25 year life rather than a 30 or 40 year life is appropriate for the Fern Facility. A 25 year life is not appropriate, and should not be used to calculate the CRF. Dr. Bowring testified:

> It is my experience that comparable solar units frequently assert that they have useful life well in excess of 25 years. Such longer life should be reflected in the CRF.[175]

Staff Witness Kevin Pewterbaugh provides detailed testimony supporting the use of a 30 year life.[176]

Witness Horigan never explained the actual cost of capital for the Fern facility or explained why the actual cost of capital should not be used in the calculation of the CRF.

In the event that a cost of service rate including a CRF is used to calculate the revenue requirement for Fern, the CRF proposed by Fern should be found unjust and unreasonable. In its place a CRF based on the approach included in the CRF Technical Reference should be calculated and used to determine a just, reasonable and nondiscriminatory revenue requirement.

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174 *See* IMM-0004 & IMM-0005.

175 *See* IMM-0001 at 11:12–14.

176 *See* Exhibit No. S-0008 REV at 4:8–10.

V. CONCLUSION

The Market Monitor respectfully requests that the Presiding Judge afford due consideration to these arguments on brief as he resolves the issues in this proceeding.

Respectfully submitted,

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Dated: February 15, 2023

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 Eagleville, Pennsylvania,

this 15th day of February, 2023.

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