UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Big Plain Solar, LLC	))))	Docket Nos. EL23-78-000, ER23-1736-002

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM IN OPPOSITION TO OFFER OF SETTLEMENT

Pursuant to Rule 602(f) of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C.[2] ("PJM"), submits this reply in opposition to the offer of settlement ("Offer") filed in this proceeding on January 8, 2024, by Big Plain Solar, LLC ("Big Plain").

Big Plain proposes on a black box basis an annual total revenue requirement for reactive capability of $600,000.00, or $3,061.22 per MW-year, or $8.39 per MW-day for the 196 MW facility, on an ICAP basis. The proposed ARR for the Big Plain facility is significantly higher than the average rate paid for reactive power in PJM. The average revenue requirement for reactive capability in PJM was $1,914 per MW-year in 2022. No justification has been provided for why customers should pay 1.60 times the average PJM price of reactive for reactive from Big Plain. There is no reasonable basis for the proposed disparity in cost for the same service. Reactive is a homogeneous product which should have the same price for all sellers. This result has not been explained or supported by Big Plain in their filing or their black box Offer. This disparity is inconsistent with competitive markets.

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1 18 CFR § 385.602(f) (2023).

2 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT").

The actual excess is larger than calculated based on the nameplate capacity of the resource. This type of resource, tracking solar, can sell only a derated level of MW in the PJM capacity auction to reflect the fact that it is not directly comparable to a thermal resource with higher availability. On an equivalent capacity basis using the class average 50.0 percent ELCC derating factor for tracking solar for the 2024/2025 Delivery Year, the Offer proposed ARR is $6,122.45 per MW-year, $16.77 per MW-day, or 58.0 percent of the $28.92 per MW-day clearing price in the last PJM capacity market auction for the Rest of RTO LDA.[3] In effect, Big Plain is proposing that customers pay a price for the reactive ancillary service alone from Big Plain equal to 58.0 percent of the price that customers pay for the full capacity value from Big Plain in the PJM Capacity Market. That result would be unreasonable and excessive and inconsistent with a competitive market. Even this comparison understates the issue, given that PJM has proposed a much lower ELCC derating value for tracking solar in its recent filing with FERC.[4] [5]

PJM has calculated that the ELCC for tracking solar for the 2024/2025 Delivery Year, using PJM's proposed marginal ELCC approach, is 20.0 percent. On an equivalent capacity basis using the updated class average 20.0 percent ELCC derating factor for tracking solar for the 2024/2025 Delivery Year, the Offer proposed ARR is $15,306.12 per MW-year, $41.93 per MW-day, or 145.0 percent of the $28.92 per MW-day clearing price in the last PJM capacity market auction for the Rest of RTO LDA. In effect, based on PJM's marginal ELCC approach, Big Plain is proposing that customers pay a price for the reactive ancillary service alone from Big Plain equal to almost one and half times (145.0 percent) the price that customers pay for the full capacity value from Big Plain in the PJM Capacity Market.

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[3] This is the currently posted ELCC value for tracking solar, based on PJM's average ELCC approach. *ELCC Class Ratings for 2024-2025, PJM Interconnection*, LLC, December 29, 2023 <*https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability*>.

[4] PJM estimated the ELCC derate value for tracking solar units to be 20 percent for the 2024/2025 delivery year under the proposed tariff revisions. *See* PJM Interconnection, L.L.C., Docket No. ER24-99-000 (October 13, 2023) Attachment E (Affidavit of Dr. Patricio Rocha-Garrido) at para. 43.

[5] PJM estimated the ELCC derate value for tracking solar units to be 25 percent for the 2025/2026 delivery year under the proposed tariff revisions. *See* PJM Responses to Deficiency Letter, Docket No. ER24-99-001 (December 1, 2023) at 26–28.

The actual excess could be even larger than calculated based on the class average derating factor of the resource. To the extent that the actual unit specific ELCC for Big Plain is below the class average, the proposed cost of reactive per MW of capacity would increase and the degree of excess would increase. The opposite would be true if the actual ELCC were greater than the class average. The actual ELCC derating factor and the actual CIR value are essential to an accurate evaluation of the actual cost per MW-day of the Big Plain proposal. The facts about the actual ELCC derating factor and the actual CIR value are confidential but can be established at hearing.

The facts relevant to whether the level of the rate proposed by Big Plain are appropriate should be established at hearing. The first issue that should be examined at hearing is why PJM customers should pay any revenue requirement to Big Plain under Schedule 2. In the recent *Midcontinent Independent System Operator, Inc. (MISO)* case, the Commission approved MISO's FPA § 205 filing revising the MISO Tariff Schedule 2 to eliminate all charges under Schedule 2 for the provision of reactive power within the standard power factor range.[6] The decision found "the provision of reactive power within the standard power factor range is, in the first instance, an obligation of the interconnecting generator and good utility practice," and there is, thus, no obligation to provide separate compensation for reactive capability.[7] The Commission explained that its holding reaffirms its policies stated, e.g., in Order No. 2003.[8] It is also consistent with the approach long used in other RTOs, including CAISO and SPP.[9] The Commission rejected arguments that reactive payments should be continued "because generators have come to rely on the compensation for Reactive Service in order for the generators to remain financially viable."[10] The Market

[6] 182 FERC ¶ 61,033 (2023).

[7] *Id*. at P 53.

[8] *Id*.

[9] *Id*. at PP 56–57.

[10] *Id*. at P 54.

Monitor has argued this position in the *Fern Solar* hearing, where its brief on exceptions to the initial decision is pending before the Commission.[11]

The Commission may approve a contested offer of settlement only based on its merits.[12] A contested settlement may be approved on its merits under one of the four approaches set forth in *Trailblazer Pipeline Company*.[13] None of the approaches under *Trailblazer Pipeline Company* can be relied on for approval of the Offer. The Offer does not resolve the issues raised in the order setting this matter for hearing.[14] There is no record supporting the revenue requirement as just and reasonable, including as a "package." The Market Monitor represents the public interest in efficient and competitive markets. The settlement cannot be analyzed under the fair and reasonable standard applicable to uncontested settlements because the public interest in efficient and competitive markets is a central issue in this proceeding. There is no possibility of severing the issues in the manner contemplated under the *Trailblazer Pipeline Company* approaches.

Although the Commission encourages settlements, that policy is not a license to resolve cases at all costs.[15] An offer of settlement, as in this case, that is unfair, unreasonable,

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[11] *See Fern Solar LLC*, Docket No. ER20-2186, et al.

[12] 18 CFR § 385.602(h)(1) ("If the Commission determines that any offer of settlement is contested in whole or in part, by any party, the Commission may decide the merits of the contested settlement issues, if the record contains substantial evidence upon which to base a reasoned decision or the Commission determines there is no genuine issue of material fact.").

[13] The four approaches for approving a settlement under *Trailblazer Pipeline Company* include: (i) addressing the contentions of the contesting party on the merits when there is any adequate record; (ii) approving a contested settlement as a package on the ground that the overall result of the settlement is just and reasonable; (iii) determining that the contesting party's interest is sufficiently attenuated such that the settlement can be analyzed under the fair and reasonable standard applicable to uncontested settlements when the settlement benefits the directly affected settling parties; or (iv) preserving the settlement for the consenting parties while allowing contesting parties to obtain a litigated result on the merits. *See Trailblazer Pipeline Company*, 85 FERC ¶ 61,345 (1998).

[14] *Big Plain Solar, LLC*, 183 FERC ¶ 61,224 at PP 13–14 (2023).

[15] *See, e.g.*, *Arkla Energy Resources*, 49 FERC ¶ 61,051, 61,217 (1989); *Transwestern Pipeline Co.*, 9 FERC ¶ 61,075, at 61,166 (1979).

or against the public interest must be rejected.[16] Instead, this case should proceed to hearing so that the record can be developed and issues of material fact and law can be resolved on the merits.

The offer of settlement is also defective because it is based on an incomplete record. The Commission has repeatedly determined that the following information must be included in a Schedule 2 filing, and has rejected filings that fail to include it:

1. the latest reactive power output test data and reports, including the PJM Reactive Capability Testing Form Sheet 1 and 2;
2. the NERC MOD-025-2 report; and
3. the PJM accepted eDART data and corresponding graph of MVAR output versus the time of the test for the facility.[17]

Big Plain did not submit the required information in support of its filing on April 27, 2023. The resulting record is deficient and does not provide a valid basis for the Commission to approve a proposed rate schedule, including a rate schedule proposed in an offer of

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16 496 F.3d at 701.

17 *See Riverstart Solar Park LLC*, 185 FERC ⁋ 61,101 at P 23 (2023); *Yellowbud Solar, LLC*, 185 FERC ¶ 61,216 at P 21 (2023); *Bishop Hill Energy LLC*, 181 FERC ⁋ 61,003, at PP 11-14 (2022), *order on reh'g*, 185 FERC ⁋ 61,056; *Covanta Del. Valley, L.P.*, 180 FERC ⁋ 61,155 at PP 17, 22–24 (2022); *Blooming Grove Wind Energy Center LLC*, 181 FERC ⁋ 61,109 (2022); *Flemington Solar, LLC*, 182 FERC ⁋ 61,110, at P 21 (2023); *Skipjack Solar Center, LLC*, 182 FERC ⁋ 61,146 at P 11 (2023); *see also Middletown Coke*, 178 FERC ⁋ 61,183 at P 10 (2022); *Paulding Wind Farm IV LLC*, 173 FERC ⁋ 61,172 at P 6 (2020); *NedPower Mount Storm, LLC*, 173 FERC ⁋ 61,177 at PP 9-10 (2020); *Wabash Valley Power Ass'n, Inc.*, 154 FERC ⁋ 61,245 at P 29 (2016).

settlement.[18] As the Commission explained in *Riverstart*, a proposed rate schedule not supported by the required information does not meet the burden of proof.[19]

Article 6.3 of the Offer's proposed settlement provides: "The Commission's approval of this Settlement shall not constitute precedent nor be used to prejudice any otherwise available rights or arguments of any party in a future proceeding." If the Offer is approved, it will unavoidably establish a benchmark rate level for facilities like the Big Plain facility. The public interest is better served by resolution of the issues raised in this proceeding on the basis of a full evidentiary record and reasoned analysis.

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[18] See 185 FERC ⁋ 61,101 at PP 21–23 ("In *Wabash*, the Commission provided general guidance on establishing or revising cost-based rates for reactive service based on the AEP-methodology 'to ensure that the Commission has sufficient information to evaluate whether the reactive power rate is just and reasonable.' Among other things, the Commission explained that the revenue requirements established pursuant to Schedule 2 of the pro forma Open Access Transmission Tariff (OATT) 'are based on a particular level of reactive power capability for a particular generating unit or group of units.' The Commission also indicated that to satisfy its reactive filing requirements, applicants proposing a cost-based rate based on the AEP-methodology must include with their reactive power revenue requirement filings reactive power test reports to support the proposed reactive power allocator used in the AEP-methodology. Soon after Wabash, the Commission clarified that '[t]o support their capability figures, generator owners should provide the most recent Reactive Service test reports produced in compliance with Standard MOD-025-2 adopted by the North American Electric Reliability Corporation."[footnote omitted]

The reactive power allocator referred to in *Wabash* plays a significant role in determining a facility's overall reactive power compensation under the AEP-methodology. Under the AEP-methodology, the relevant groups of production power plant investment involve both reactive and real power, and so an allocation factor is developed to sort the annual revenue requirements of facility components between real and reactive power production.[footnote omitted] More specifically, the 'reactive power allocator'—based on the ratio of $MVAR^2$ to MVA^2, which translates algebraically into $1 - (\text{power factor})^2$—is applied to the amount of generator-exciter investment, generator step up transformers investment, and accessory electric equipment investment,[footnote omitted] which for many facilities can be substantial.[footnote omitted] A facility's reactive power compensation therefore depends heavily on its reactive allocator, and thus, in turn, on its power factor, which is the revenue requirement calculation component that reactive power test information is used to support.[footnote omitted]

Also since *Wabash*, the Commission has continued to see an increasing number of filings by generators seeking reactive power compensation under the AEP-methodology. In its consideration of such cases, the Commission has applied its corresponding increased expertise in this area, such that it has identified particular data and test reports that are necessary to analyze and evaluate an applicant's reactive power revenue requirement, including proposed reactive power allocators.").

[19] 185 FERC ⁋ 61,101 at P 23.

In the attached affidavit of Dr. Joseph E. Bowring ("Affidavit"), included pursuant to Rule 602(f)(4), Dr. Bowring explains why the requested revenue requirements are excessive and unsupported.[20]

The issues raised in this proceeding have significant cost implications going forward. Failing to resolve these issues means that customers must make payments to the facilities and similar facilities at levels exceeding the competitive and reasonable level for the facilities. Resolution of these issues should not be deferred. There is significantly greater administrative efficiency if new issues are resolved now, rather than after years of baseless and arbitrary settlements.

In the Affidavit, Dr. Bowring explains why the level of the annual revenue requirement is excessive. The issue of an appropriate rate level under Schedule 2 needs resolution on the merits in this case and for future cases. The Market Monitor opposes the Offer. The Offer should be rejected. Further, settlement discussions in the proceeding should be terminated, and the issues raised in this proceeding should be decided on the merits.

Respectfully submitted,

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20 18 CFR § 385.602(f)(4).

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Dated: January 29, 2024

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 29th day of January, 2024.

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**UNITED STATES OF AMERICA
BEFORE THE
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Big Plain Solar, LLC	))))	Docket Nos. EL23-78-000, ER23-1736-002

AFFIDAVIT OF JOSEPH E. BOWRING ON BEHALF OF THE INDEPENDENT MARKET MONITOR FOR PJM

Q 1. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Joseph E. Bowring. I am the Market Monitor for PJM. I am the President of Monitoring Analytics, LLC. My business address is 2621 Van Buren Avenue, Suite 160, Eagleville, Pennsylvania. Monitoring Analytics serves as the Independent Market Monitor (IMM) for PJM, also known as the Market Monitoring Unit (Market Monitor). Since March 8, 1999, I have been responsible for all the market monitoring activities of PJM, first as the head of the internal PJM Market Monitoring Unit and, since August 1, 2008, as President of Monitoring Analytics. The market monitoring activities of PJM are defined in the PJM Market Monitoring Plan, Attachment M and Attachment M-Appendix to PJM Open Access Transmission Tariff (OATT).[1]

Q 2. WHAT IS THE PURPOSE OF YOUR AFFIDAVIT?

A. The purpose of my affidavit is to explain the Market Monitor's opposition to the offer of settlement ("Offer") of the annual revenue requirement ("ARR") filed in this proceeding by Big Plain Solar, LLC ("Big Plain"), which owns and operates a 196 MW solar generating facility located near London, Ohio, and interconnected with the transmission system of American Transmission Systems, Inc. ("Big Plain Facility").

1 *See PJM Interconnection, L.L.C.*, 86 FERC ¶ 61,247 (1999); 18 CFR § 35.34(k)(6).

Q 3. HAVE YOU PROVIDED TESTIMONY ON COMPENSATION FOR REACTIVE POWER IN OTHER PROCEEDINGS BEFORE THE FERC?

A. Yes. I provided testimony in the *Panda Stonewall* reactive supply capability case (Docket No. ER21-1821-002); the *Whitetail Solar 3, et al.* reactive supply capability case (Docket No. ER20-1851-004 et al.); *Mechanicsville Solar, LLC*, reactive supply capability case (Docket No. ER21-2091-000); the *Holloman Lessee, LLC* reactive supply capability case (Docket No. ER20-2576-001); and the *Fern Solar LLC* reactive supply capability case (ER20-2186-003, et al.). I provided an affidavit in support of opposition to an offer of settlement in the *Meyersdale Storage, LLC*, reactive supply capability case (ER21-864-000); the *Bluestone Farm Solar, LLC*, reactive supply capability case (ER21-1696-000); the *Altavista Solar, LLC*, reactive supply capability case (ER21-1937); the *Pleinmont Solar 1, LLC et al.*, reactive supply capability case (ER21-2819 et al.); the *Camp Grove Wind Farm*, reactive supply capability case (ER21-2919); the *Crescent Ridge LLC*, reactive supply capability case (ER22-387); *PSEG Energy Trade & Resources LLC*, reactive supply capability case (ER22-351); *Grand Ridge Energy LLC* reactive supply capability case (ER19-2925); the *Panda Hummel Station LLC* reactive supply capability case (ER19-391-005); and *South Field Energy LLC* reactive capability case (ER21-2819-003); the *Eagle Creek Reusens Hydro, LLC, et al.* reactive capability case (ER21-2832 et al.); the *Pinnacle Wind, LLC* reactive capability case (ER22-507-000); the *Parkway Generation Keys Energy Center LLC, et al.*, reactive capability case (ER22-279-000, et al.); the *Hawtree Farm Creek Solar, L.P.*, reactive capability case (ER22-1076-001); the *Holloman Lessee, LLC*, reactive capability case (ER20-2576-001); the *Albemarle Beach Solar, LLC*, reactive capability case (ER21-2364-001); the *Wildwood Lessee, LLC*, reactive capability case (ER22-763-000); the *Covanta Delaware Valley, L.P., et al.*, reactive capability case (ER22-965-004); the *Jackson Generation, LLC* reactive capability case (ER22-1089-000, et al.); the *Black Rock Wind Force, LLC* reactive capability case (ER22-944-000); the *Blooming Grove Wind Energy Center LLC* reactive capability case (ER22-2148-000, et al.); *Indeck Niles, LLC* reactive capability case (ER22-907-000, et al.); the *Seneca Generation, LLC, et al.*, reactive capability case (ER14-1400-002, et al.); the *Red Oak Power, LLC*, reactive capability case (ER22-2946-001); the *Bellflower Solar 2, LLC*, reactive capability case (ER23-628-002); the *Headwaters Wind Farm II, LLC*, reactive capability case (ER23-1211-000, et al.); the *CPV Three Rivers LLC*, reactive capability case (ER23-982-000 et al.); and the *Skipjack Solar Center, LLC*, reactive capability case (ER23-2048-004).

Q 4. HAVE YOU PARTICIPATED IN OTHER FERC PROCEEDINGS RELATED TO REACTIVE POWER?

A. Yes, I was invited to participate in a Commission technical conference and provided comments to the Commission in a proceeding convened to “discuss compensation for Reactive Supply and Voltage Control (Reactive Supply) within the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs).”[2] Specifically, the proceeding explored “types of costs incurred by generators for providing Reactive Supply capability and service; whether those costs are being recovered solely as compensation for Reactive Supply or whether recovery is also through compensation for other services; and different methods by which generators receive compensation for Reactive Supply (e.g., Commission-approved revenue requirements, market-wide rates, etc.).”[3]

On February 22 and March 23, 2022, the Market Monitor filed comments and reply comments responding to the Commission’s Notice of Inquiry in Docket No. AD22-2. The Notice of Inquiry included questions (at P 28 (question no. 5.d)) specifically addressing the over recovery issue. The Notice of Inquiry also included questions (at PP 20–28 (question no. 5) addressing the appropriateness of continuing to use the *AEP* Method in reactive capability proceedings.

The Market Monitor has intervened in and actively participated in FERC reactive power cases during the past five years.

The Market Monitor includes analysis and recommendations related to reactive power in the State of the Market Reports for PJM.[4]

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2 *Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD16-17-000. I participated in a workshop convened June 20, 2016. The Market Monitor filed comments on July 29, 2016, and reply comments on September 20, 2016.

3 *Id*. at 1.

4 *See*, for example, *2021 Annual State of the Market Report for PJM*, Section 10 (Ancillary Services Markets), which can be accessed at: <*http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021.shtml*>.

I.

Q 5. WHY SHOULD THE PROPOSED ANNUAL REVENUE REQUIREMENT FOR THE BIG PLAIN FACILITY BE REJECTED?

A. Big Plain proposed an annual revenue requirement (ARR) of $3,904,557.24 per year, or $19,921.21 per MW-year, or $54.58 per MW-day. The proposed ARR is excessive. The Offer proposes, on a black box basis, an ARR of $600,000.00 per year, or $3,061.22 per MW-year, or $8.39 per MW-day. The proposed Offer ARR is excessive.

The Offer's proposed ARR is a disproportionately large share of the total capital costs of the resource. The proposed ARR is significantly higher than the average rate paid for reactive power in PJM, $1,914 per MW-year in 2022. The proposed black box ARR for the Big Plain Facility is $8.39 per MW-day for the reactive ancillary service alone, or 29.0 percent of the $28.92 per MW-day clearing price for capacity in the last PJM capacity market auction (BRA for the 2024/2025 Delivery Year) for the ATSI where the plant is located.

The actual excess is larger than calculated based on the nameplate capacity of the resource. This type of resource, tracking solar, can sell only a derated level of MW in the PJM capacity auction to reflect the fact that it is not directly comparable to a thermal resource with higher availability. On an equivalent capacity basis using the class average 50.0 percent ELCC derating factor for tracking solar for the 2024/2025 Delivery Year, the Offer proposed ARR is $6,122.45 per MW-year, $16.77 per MW-day, or 58.0 percent of the $28.92 per MW-day clearing price in the last PJM capacity market auction for the Rest of RTO LDA.[5] In effect, Big Plain is proposing that customers pay a price for the reactive ancillary service alone from Big Plain equal to 58.0 percent of the price that customers pay for the full capacity value from Big Plain in the PJM Capacity Market. That result would be unreasonable and excessive and inconsistent with a competitive market. Even this

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[5] This is the currently posted ELCC value for tracking solar, based on PJM's average ELCC approach. *ELCC Class Ratings for 2024-2025, PJM Interconnection*, LLC, December 29, 2023 <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

comparison understates the issue, given that PJM has proposed a much lower ELCC derating value for tracking solar in its recent filing with FERC.[6] [7]

PJM has calculated that the ELCC for tracking solar for the 2024/2025 delivery year, using PJM's proposed marginal ELCC approach, is 20.0 percent. On an equivalent capacity basis using the updated class average 20.0 percent ELCC derating factor for tracking solar for the 2024/2025 Delivery Year, the Offer proposed ARR is $15,306.12 per MW-year, $41.93 per MW-day, or 145.0 percent of the $28.92 per MW-day clearing price in the last PJM capacity market auction for the Rest of RTO LDA. In effect, based on PJM's marginal ELCC approach, Big Plain is proposing that customers pay a price for the reactive ancillary service alone from Big Plain equal to almost one and half times (145.0 percent) the price that customers pay for the full capacity value from Big Plain in the PJM Capacity Market.

However, the actual excess could be larger than calculated based on the class average derating factor of the resource. To the extent that the actual unit specific ELCC for Big Plain is below the class average, the proposed cost of reactive per MW of capacity would increase and the degree of excess would increase. The opposite would be true if the actual ELCC were greater than the class average. The actual ELCC derating factor and the actual CIR value are essential to an accurate evaluation of the actual cost per MW-day of the Big Plain proposal. The facts about the actual ELCC derating factor and the actual CIR value are confidential but can be established at hearing.

The proposed Offer ARR of $3,061.22 per MW-year exceeds the $2,199 per MW-year level of the EAS offset included in the PJM capacity market demand curve by 39.2 percent. The ARR should be capped at the energy and ancillary services (EAS)

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[6] PJM estimated the ELCC derate value for tracking solar units to be 20 percent for the 2024/2025 delivery year under the proposed tariff revisions. *See* PJM Interconnection, L.L.C., Section 205 Filing, Docket No. ER24-99-000 (October 13, 2023) Attachment E (Affidavit of Dr. Patricio Rocha-Garrido) at para. 43.

[7] PJM estimated the ELCC derate value for tracking solar units to be 25 percent for the 2025/2026 delivery year under the proposed tariff revisions. See PJM's response to Question 7 in *Responses to Deficiency Letter*, Docket No. ER24-99-000 (December 1, 2023).

offset for the current delivery year, $2,199 per MW-year, or $6.02 per MW-day.[8] The proposed black box ARR would require customers to pay $168,996 more per year than if the $2,199 per MW-year value were used.

Even within the framework of Big Plain's filing, the proposed annual carrying charge is incorrect and not adequately supported. The Market Monitor has calculated an appropriate capital recovery factor ("CRF").

The proposed ARRs are excessive, have not been demonstrated to have a rational basis, have not been demonstrated to be just and reasonable, and should be rejected.[9] The average revenue requirement for reactive capability in PJM was $1,914 per MW-year in 2022.[10] The revenue requirement for reactive capability included in the PJM Capacity Market for the current delivery year is $2,199 per MW-year.

There is no reasonable basis for the proposed disparity in cost for the same service. No justification has been provided for why customers should pay 1.60 times the average PJM price of reactive for reactive from Big Plain. Reactive is a homogeneous product which should have the same price for all sellers. This result

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8 The energy and ancillary services offset for reactive revenues included in the PJM capacity demand curve (VRR curve) (EAS Offset) is set forth in Section 5.10(v-1)(A) of Attachment DD to the OATT. Current capacity prices through the 2024/2025 Delivery Year were set using an EAS Offset of $2,199 per MW-year. The EAS Offset for reactive revenues was calculated by the Market Monitor and was based solely on Schedule 2 revenues. Effective December 21, 2022, the EAS Offset was revised to $2,546 per MW-year for Delivery Years beginning with 2026/2027. *See PJM Interconnection, L.L.C*, 182 FERC ¶ 61,073 (2023). The new EAS Offset is based on the total settled reactive revenue requirement for a combined-cycle plant included in the 2022 Quarterly State of the Market Report for PJM: January through June (August 11, 2022) at 603, Table 10-67. *Id*. at P 135. As a result, starting with the 2026/2027 Delivery Year, the maximum rate consistent with the EAS Offset will be $2,546 per MW-year.

9 *See American Electric Power Service Corp.*, 80 FERC ¶ 63,006 (1997), *aff'd*, 88 FERC ¶ 61,141 (1999); *see also Reactive Power Capability Compensation*, Notice of Inquiry, 177 FERC ¶ 61,118 (2021) ("Notice of Inquiry").

10 *See 2022 Annual State of the Market Report for PJM*, Vol. 2 (March 9, 2023) at 619–620, Table 10-78.

has not been explained or supported by Big Plain in their filing or their black box Offer. This disparity is inconsistent with competitive markets.

II.

Q 6. HOW DO PJM MARKET RULES PROVIDE THE OPPORTUNITY TO RECOVER REACTIVE CAPABILITY COSTS?

A. The PJM market 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 of the EAS offset in the Net CONE parameter of the capacity market demand (VRR) curve.[11] 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.

Q 7. HOW DOES THE REACTIVE EAS OFFSET PER MW-YEAR NUMBER AFFECT THE DEMAND CURVE FOR CAPACITY?

A. Elimination of the reactive EAS offset of $2,199 per MW-year would mean that the prices on the capacity market demand curve (VRR curve) for each MW level would be higher and the clearing prices for capacity that result from the interaction of the supply curve and the VRR curve, would be higher. The result would be the recovery of additional reactive capacity revenues in the price of capacity for all resources.

Q 8. WHY IS THE DEMAND CURVE RELEVANT?

A. If there were no nonmarket recovery of reactive revenue, there would be no reactive revenue offset to Net CONE and the demand curve would result in higher capacity market prices, all else held constant. If there were no nonmarket recovery of reactive revenue, the shape and location of the demand curve would give unit owners the opportunity to recover all reactive capability costs in the capacity market.

This is how the capacity market works for all the other costs of a generating plant other than short run marginal costs.

Payments based on cost of service approaches result in distortionary impacts on PJM markets. Elimination of the reactive revenue requirement and the recognition that capital costs are not distinguishable by function would increase prices in the

[11] *See* OATT Attachment DD § 5.10(a)(v)(A).

capacity market. The VRR curve would shift to the right, the maximum VRR price would increase and offer caps in the capacity market would increase. The simplest way to address this distortion would be to recognize that all capacity costs are recoverable in the PJM markets.

The best approach would be to eliminate cost of service rates for reactive capability and allow for recovery of capacity costs through existing markets, including a removal of any offset for reactive revenue in offers and in the capacity market demand (VRR) curve. A second best approach would be to limit the revenue requirement that could be filed for under the OATT Schedule 2 to a level less than or equal to the reactive revenue credit included in the capacity market design, in the VRR curve Net CONE value, $2,199 per MW-year for the current delivery year.

III.

Q 9. SHOULD THE *AEP* METHOD BE USED TO CALCULATE THE RATE FOR THE FACILITIES?

A. No. The current process does not actually compensate resources based on their costs of investment in reactive power capability. The *AEP* Method assigns costs between real and reactive power based on a unit's power factor. This is effectively an allocation based on a subjective judgment rather than actual investment. There are few if any identifiable costs incurred by generators in order to provide reactive power. Separately compensating resources based on a judgment based allocation of total capital costs was never and is not now appropriate in the PJM markets. Generating units are fully integrated power plants that produce both the real and reactive power required for grid operation.

The *AEP* Method originated with a regulated utility assigning costs between two sources of regulated revenue requirement. 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.

There is no logical reason to have a separate fixed payment for any part of the capacity costs of generating units in PJM. If separate cost of service rates for reactive continue, they need to be correctly integrated in the PJM market design.

The best and straightforward solution is to remove cost of service rates for reactive supply capability and to remove the offset. Investment in generation can and should be compensated entirely through markets. Removing cost of service rules would avoid the significant waste of resources incurred to develop unneeded cost of service rates.

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

The *AEP* Method never accurately reflected the investment costs of providing reactive power, nor was it intended to do so. 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. 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. The *AEP* Method was never about actually identifying specific capital costs associated solely with the provision of reactive power. Cost of service approaches apply allocation factors to accounting line items based on assumptions. 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. The false precision of the *AEP* Method is entirely based on arbitrary assumptions. 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. That is not what the *AEP* Method was intended to do or is intended to do. The *AEP* Method does not define costs that are uniquely associated with the production of reactive power.

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.

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. 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). 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 $(1 – (\text{PowerFactor})^2)$. The power factor has superficial attraction as an appropriate allocator. The power factor is the core determinant of the reactive allocation factor in the *AEP* Method. Small changes in the power factor have large impacts on the costs allocated to reactive power. 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. For a resource claiming a power factor of .70, does that mean that more than half of the generator's costs were incurred in order to provide reactive power? Does this mean that 51 percent of the costs of the generator, exciter, and electrical equipment should be recovered through a cost of service rate? The answer to both questions is no. But resources have filed for guaranteed reactive revenue requirements on that basis.

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. 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. 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. The nameplate power factor of thermal generating units is typically .85. But the nameplate power factor stamped on the generator at the factory is not based on actual operation on an actual grid. The nameplate power factor is meaningless for the actual operation of the power plant. 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.

The power factor is not an appropriate allocator and does not reflect the actual capital costs associated with producing reactive power. 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. That significance illustrates the fundamental flaws in the *AEP* Method.

The power factor does not measure reactive capability. The power factor does not determine a plant's reactive capability. 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.

IV.

Q 10. WHAT ARE THE ISSUES WITH THE COMPANY'S PROPOSED ANNUAL CARRYING CHARGE CALCULATION?

A. In its April 27, 2023 filing, Big Plain calculated a carrying cost percentage which is a form of capital recovery factor (CRF). This CRF was presented in the prepared direct testimony of W. Wade Horigan on April 27, 2023.[12] 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 did not include an income tax component because, in his words, "Big Plan Solar is a pass through entity."[13] Witness Horigan's derivation does not accurately reflect the tax liability and the return on and the return of the capital investment. Most notably, the Horigan derivation does not account for bonus depreciation or investment tax credits, two valuable tax benefits available to solar power development projects.[14]

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. The Market Monitor's CRF accurately reflects the tax liability associated with the annual payment. The depreciation used in the calculation of the CRF should reflect the depreciation used for tax purposes. The sinking fund depreciation factor does not reflect the actual depreciation used by Big Plain and therefore should not be used in the calculation of the revenue requirement for the Big Plain Facility.

Witness Horigan did not account for the actual tax treatment of the facility and did not adequately explain his tax treatment, did not adequately explain or support his depreciation method, and did not account for the actual cost of capital of the facility.

Q 11. **HOW DO YOU PROPOSE TO CALCULATE THE CAPITAL RECOVERY FACTOR (CRF)?**

A. The best approach for calculating capital recovery over a defined period is the Capital Recovery Factor (CRF) approach used by the Market Monitor. I have attached to my testimony as Exhibit No. IMM-0003, a Capital Recovery Factor (CRF) Technical Reference prepared by the Market Monitor. The technical

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12 *See* BPS-1 at 23:5–25:10.

13 See BPS-1 at 24:17.

14 Solar power development projects are eligible for either an investment tax credit (ITC) or a production tax credit (PTC). If Big Plain received an ITC, the value of the ITC should be reflected in the reactive revenue requirement

reference explains in detail the components for accurately and consistently calculating a CRF.

The CRF should be required for use in all cost based ratemaking provisions used in PJM, which now include black start service rates and reactive capability rates.

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) valuation 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. FERC accepted this approach for black start service and directed PJM to include the CRF formula in the PJM tariff.[15] Additional details on the derivation of the CRF formula and examples are available in the Market Monitor's CRF Technical Reference.

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 results are shown in Exhibit No. IMM-0004 and IMM-0005. For a 20 year cost recovery period, the Market Monitor's CRF is 0.094826 and, based on Horigan's asserted capital cost and financing structure, the corresponding annual revenue payment would be $2,502,551.[16] [17] Assuming a 20 year cost recovery term, the Market Monitor's annual capital cost recovery payment is $997,830 lower than the amount proposed by Witness Horigan.[18] The Market Monitor's annual revenue payment includes the effect of both bonus depreciation and ITC. The CRF calculation directly includes the bonus depreciation and the ITC

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

16 The formula for the CRF is equation (1.4) in the CRF Technical Reference. The calculation assumes the half year convention for the timing of revenue and tax payments.

17 This value reflects the capital cost recovery and does not include fixed operating expenses.

18 Exhibit No. IMM-0004.

is a reduction to the capital investment to be recovered through the reactive payment.

The Market Monitor's annual revenue payment in Exhibit No. IMM-0004 reflects a reduction to the reactive capital cost to account for an investment tax credit (ITC). The Big Plain solar plant would have been eligible for an ITC and it should be reflected in the reactive cost recovery. The annual payment for capital cost recovery proposed by Witness Horigan does not appear to reflect an ITC. 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 80 percent bonus depreciation that allows generators placed in service in 2023, to depreciate 80 percent of the capital investment in the first year of operation. Exhibit No. IMM-0005 shows the Market Monitor's proposed capital cost recovery excluding the effect of the ITC.

Exhibit No. IMM-0004 also shows the CRFs and corresponding capital recovery payments for recovery periods exceeding 20 years. For example, the Market Monitor's CRF for a 40 year cost recovery period is 0.075822. The corresponding annual payment is $2,001,010.[19]

Witness Horigan has not explained why a 20 year life rather than a 35 or 40 year life is appropriate for the Big Plain Facility. It is my experience that comparable solar units frequently assert that they have a useful life in excess of 30 years. Such longer life should be reflected in the CRF. The tables in Exhibit No. IMM-0004 and No. IMM-0005 are included only to illustrate the implications of the issues with the company's CRF calculations, based on the assumptions that the company's allocation of costs to reactive are correct. I do not support using the annual revenue requirements in Exhibit Nos. IMM-0004 and IMM-0005, but include the calculations solely for the purpose of showing the implications of the incorrect and overstated CRF calculations used by Big Plain and the inappropriate exclusion of ITC by Big Plain.

Q 12. DOES THIS CONCLUDE YOUR AFFIDAVIT?

A. Yes.

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[19] This value reflects the capital cost recovery and does not include fixed operating expenses.

Exhibit No. IMM-0002
PJM OATT Schedule 2

PJM OATT Schedule 2 - Reactive Supply and Voltage Control from Generation or Other Sources Service

SCHEDULE 2
Reactive Supply and Voltage Control from Generation or Other Sources Service

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. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider. The Transmission Customer must purchase this service from the Transmission Provider.

In addition to the charges and payments set forth in this Tariff, Schedule 2, Market Sellers providing reactive services at the direction of the Office of the Interconnection shall be credited for such services, and Market Participants shall be charged for such services, as set forth in Tariff, Attachment K-Appendix, section 3.2.3B.

The Transmission Provider shall administer the purchases and sales of Reactive Supply. PJMSettlement shall be the Counterparty to (a) the purchases of Reactive Supply from owners of Generation or Other Sources and Market Sellers and (b) the sales of Reactive Supply to Transmission Customers and Market Participants.

Charges

Purchasers of Reactive Supply and Voltage Control from Generation or Other Sources Service shall be charged for such service in accordance with the following formulae.

> Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation Owner or other source owner Monthly Revenue Requirement
>
> Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation Owner or other source owner Monthly Revenue Requirement * Adjustment Factor
>
> Where:

Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or serving Network Load in a zone with no revenue requirement for Reactive Supply and Voltage Control from Generation or Other Sources Service, or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region.

Zonal Generation Owner or other source owner Monthly Revenue Requirement is the sum of the monthly revenue requirements for each generator or other source located in a Zone, as such revenue requirements have been accepted or approved, upon application, by the Commission.

Total Generation Owner or other source owner Monthly Revenue Requirement is the sum of the Zonal Generation or other source owner Monthly Revenue Requirements for all Zones in the PJM Region.

Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis.

For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Tariff, Part III, section 34.1) as applicable, for all days of the month.

For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity for each day of the month (not curtailed by PJM) divided by the number of hours in the day.

Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region, exclusive of such use by Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.

In the event that a single customer is serving load in more than one Zone, or serving Non-Zone Load as well as load in one or more Zones, or is both a Network Customer and a Transmission Customer, the Monthly Charge for such a customer shall be the sum of the Monthly Charges determined by applying the appropriate formulae set forth in this Schedule 2 for each category of service.

Payment to Generation or Other Source Owners

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. In the event a Generation Owner or other source owner sells a generator or other source which is included in its current effective monthly revenue requirement accepted or approved by the Commission, payments in that Generation Owner's or other source owner's Zone may be allocated as agreed to by the owners of the generator or other source in that Zone. Such Generation Owner or other source owners shall inform the Transmission Provider of any such agreement and submit either a filing to revise its cost-based rate or an informational filing in accordance with the requirements below in this Schedule 2. In the absence of agreement among such Generation Owners or other source owners, the Commission, upon application, shall establish the allocation. Generation Owners shall not be eligible for payment, pursuant to this Schedule 2, of monthly revenue requirement associated with those portions of generating units designated as Behind The Meter Generation. The Transmission Provider shall post on its website a list for each Zone of the annual revenue requirements for each Generation Owner receiving payment within such Zone and specify the total annual revenue requirement for all of the Transmission provider.

At least 90 days prior to the Deactivation Date or disposition date of a generator or other source receiving payment in accordance with a Commission accepted or approved revenue requirement for providing reactive supply and voltage control service under this Schedule 2, the Generation Owner or other source owner must either:

(1) submit to the Commission the appropriate filings to terminate or revise its cost-based revenue requirement for supplying reactive supply and voltage control service under this Schedule 2 to account for the deactivated or transferred generator or other source; or

(2) provide to the Transmission Provider and file with the Commission an informational filing that includes the following information:

(i) the acquisition date, Deactivation Date, and transfer date of the generator or other source;

(ii) an explanation of the basis for the decision by the Generation Owner or other source owner not to terminate or revise the cost-based rate approved or accepted by the Commission associated with the planned generator or other source deactivation or disposition;

(iii) a list of all of the generators or other sources covered by the Generation Owner's or other source owner's cost-based tariff from the date the revenue requirement was first established until the date of the informational filing;

(iv) the type (i.e., fuel type and prime mover) of each generator or other source;

(v) the actual (site-rated) megavolt-ampere reactive ("MVAR") capability, megavolt-ampere ("MVA") capability, and megawatt capability of each generator or other source, as supported by test data; and

(vi) the nameplate MVAR rating, nameplate MVA rating, nameplate megawatt rating, and nameplate power factor for each generator or other source.

The Generation Owner or other source owner must submit the informational filing in the docket in which its cost-based revenue requirement was approved or accepted by the Commission or as otherwise directed by the Commission.

The requirement to submit the filings at least 90 days prior to the Deactivation Date or disposition date of a generator or other source shall not apply to generators or other source deactivations or transfers occurring between June 18, 2015, and September 16, 2015. For generator or other source deactivations or transfers occurring between June 18, 2015, and September 16, 2015, the Generation Owner or other source owner shall submit the informational filing or filings to terminate or revise its cost-based revenue requirement by September 16, 2015.

Exhibit No. IMM-0003
Capital Recovery Factors
Technical Reference

Exhibit No IMM-0003
Docket Nos. ER23-1736 and EL23-78

Capital Recovery Factors (CRF) Technical Reference

Monitoring Analytics, LLC

April 25, 2022

Table of Contents

1 The Basics of CRF

A capital recovery factor (CRF) is used to convert the principal amount of a capital investment into an equivalent stream of uniform payments. A typical CRF formula found in engineering economics textbooks is given in equation (1.1).[1]

(1.1)

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1}$$

Variable r is an interest rate, N is the number of uniform annual payments and the payments are assumed to occur at the end of year. To derive equation (1.1) the CRF is first denoted by c, allowing the annual payment to be stated as $A = cK$ where K is the capital investment. Then c is the value that solves the following present value equation,

$$\begin{aligned} K &= \sum_{j=1}^{N} \frac{cK}{(1+r)^j} \\ &= cK \sum_{j=1}^{N} \left(\frac{1}{1+r}\right)^j \end{aligned}$$

The summation in the equation above is a finite geometric series. A general formula for the sum of a finite geometric series is given by

(1.2)

$$\sum_{j=H}^{W} v^j = \frac{v^H}{1-v}\left(1 - v^{W-H+1}\right).$$

H and W are positive integers and v is any number except one ($v \neq 1$). It is straightforward exercise to show that equation (1.2) is valid.[2]

Using equation (1.2) with $H = 1$, $W = N$ and $v = 1/(1+r)$ yields

$$\sum_{j=1}^{N} \left(\frac{1}{1+r}\right)^j = \frac{(1+r)^N - 1}{r(1+r)^N}.$$

Replacing the summation in the present value equation yields

$$K = cK\left(\frac{(1+r)^N - 1}{r(1+r)^N}\right)$$

[1] For example, see pages 21-22 in "Economic Evaluation and Investment Decision Methods," Stermole, F.J. and Stermole, J.M. (1993).

[2] If S is the sum on the left hand side of equation (1.2), then $S - vS = v^H - v^{W+1}$ and solving for S gives the right hand side of (1.2).

and solving for c produces equation (1.1).

1.1 CRF That Reflect Taxable Income

The revenue that results from a capital investment is taxable income. The revenue payment A, obtained by multiplying the capital investment amount K by the CRF in equation (1.1), would be too low in cases where the revenue is taxable. The goal, in the presence of taxes, is to have a CRF for which the product $CRF \cdot K$ yields an annual payment A that will provide the necessary and sufficient level of revenue to cover the investors' annual tax payments, and the return on and return of the capital investment. In other words, over the life of the project, the revenue in excess of the tax payments and investment return should equal the original capital investment. The annual revenue payment can be determined by solving an equation where the present value of the after tax cash flows resulting from the annual revenue payment is equal to the initial capital investment.

The composition of the after tax cash flow is dependent upon the capital budgeting model. The weighted average cost of capital (WACC) approach was used to develop the CRF for PJM Black Start Service which was accepted by FERC in August 2021.[3] [4] The WACC approach to capital budgeting discounts the after tax cash flow at the after tax weighted average cost of capital rate and payback of the investment in each recovery year reflects the assumed debt and equity financing structure.[5] The CRF must satisfy the following present value equation,

$$K = \sum_{j=1}^{N} \frac{CF_j}{(1+r)^j} \ .$$

K is the capital investment, CF_j is the after tax cash flow for year j, r is the WACC rate, and the revenue, tax and debt payments are assumed to occur at the end of the year. The model variables are defined in Table 1-1. In the WACC model, the after tax cash flow is revenue net of taxes, and the tax calculation includes an offset for depreciation. The after tax cash flow for year j is

$$\begin{aligned} CF_j &= cK - \left(cK - \delta_j K\right)s \\ &= cK(1-s) + \delta_j K s \end{aligned}$$

[3] 176 FERC ¶ 61,080 (August 10, 2021) at 43-44.

[4] Additional details on the weighted average cost of capital approach to capital budgeting can be found in Section 17.3 in "Corporate Finance," Ross, Westerfield, Jaffe, 4th Edition, 1996.

[5] The after tax weighted average cost of capital rate is equal to *Equity Funding Percent* x *Equity Rate* + *Debt Funding Percent* x *Debt Interest Rate* x (1- *Effective Tax Rate*).

where c is the CRF, K is the total capital investment including debt and equity, cK is the annual revenue payment, s is the effective tax rate and δ_j is the depreciation factor for year j. Upon replacing CF_j in the present value equation

$$K = cK(1-s)\sum_{j=1}^{N}\frac{1}{(1+r)^j} + Ks\sum_{j=1}^{N}\frac{\delta_j}{(1+r)^j}.$$

Equation (1.2) with $H = 1$, $W = N$ and $v = 1/(1+r)$ gives

$$\sum_{j=1}^{N}\frac{1}{(1+r)^j} = \frac{(1+r)^N - 1}{r(1+r)^N}$$

and substituting into the previous equation results in

$$K = cK(1-s)\left(\frac{(1+r)^N - 1}{r(1+r)^N}\right) + Ks\sum_{j=1}^{N}\frac{\delta_j}{(1+r)^j}.$$

Solving for c yields the CRF formula in equation (1.3).

(1.3)

$$CRF = \frac{r(1+r)^N}{(1-s)[(1+r)^N - 1]}\left\{1 - s\sum_{j=1}^{N}\frac{\delta_j}{(1+r)^j}\right\}$$

Table 1-1 Variable descriptions for the WACC capital budgeting model

Variable	Description
r	After tax weighted average cost of capital
s	Effective tax rate
N	Cost recovery period
δ_j	Depreciation factor for recovery year *j*

Substituting the parameter values shown in Table 1-2 into the CRF formula, assuming a five year capital recovery period and straight line depreciation yields a CRF of 0.274938. With a capital investment of $1 million, the annual payment is $274,938.

Table 1-3 provides a cash flow summary for a $1 million capital investment with a five year cost recovery period that uses straight line depreciation. The revenue for each year, equal to the product of the CRF and the capital investment amount, is $274,938. The tax payment for each year is equal to the effective tax rate times the revenue net of depreciation. The return on the capital investment in year 1 is equal to the product of the WACC rate and the initial capital investment of $1,000,000.

Table 1-2 Financial parameter and tax assumptions[6]

Parameter	Parameter Value
Equity Funding Percent	50.0000%
Debt Funding Percent	50.0000%
Equity Rate	12.0000%
Debt Interest Rate	7.0000%
Federal Tax Rate	21.0000%
State Tax Rate	9.0000%
Effective Tax Rate (s)	28.1100%
After tax Weighted Average Cost of Capital (r)	8.5162%

After accounting for the tax payment and return on investment in year 1, $168,711 is available as payback to the investors. The remaining capital investment is $831,289 at the end of year 1. The year 2 return on investment is the product of the WACC rate and the remaining capital investment at the end of year 1. Payback to investors is $183,079 in year 2. The cash flows for years 3 through 5 are analogous to the year 2 cash flow.

Table 1-3 Cash flow summary for 5 year, $1 million investment with straight line depreciation[7]

Recovery Year	1	2	3	4	5
Revenue	$274,938	$274,938	$274,938	$274,938	$274,938
Depreciation	$200,000	$200,000	$200,000	$200,000	$200,000
Tax Payment	$21,065	$21,065	$21,065	$21,065	$21,065
Return on capital investment	$85,162	$70,794	$55,202	$38,283	$19,923
Capital investment payback	$168,711	$183,079	$198,670	$215,590	$233,949
Remaining capital investment	$831,289	$648,209	$449,539	$233,949	$0

After the final revenue payment in year 5, the remaining capital investment is reduced to $0. Summing horizontally across the capital investment payback row in Table 1-3 produces $1,000,000. This example illustrates that the revenue payment determined by the CRF provides the necessary and sufficient annual revenue to pay the taxes associated with the revenue payment as well as the required return on and return of the capital investment. This important point is established as a general result in the following proposition.

Proposition 1.1. The CRF given by equation (1.3) is the unique value, assuming a WACC capital budgeting model with end of year payments, for which the resulting annual revenue payment is

6 The effective tax rate (parameter s in the formula) is equal to *State Tax Rate + Federal Tax Rate x (1-State Tax Rate).*

7 WACC model with end of year revenue and tax payments.

necessary and sufficient, over the term of the investment, to provide for the annual tax liability and the return on and return of the capital investment.

1.2 Half Year Convention

The revenue and tax payments would likely be made on a monthly or quarterly basis rather than occurring at the end of the year. A better model with respect to the timing of the revenue and tax payments is obtained by assuming the revenue and tax payments occur at the midpoint of each year. To derive a CRF corresponding to midyear revenue and tax payments, the present value equation from the previous section is modified to reflect the new timing assumption. Each after tax cash flow amount is assumed to occur a half year earlier than in the previous model. The revised present value equation is

$$K = \sum_{j=1}^{N} \frac{CF_j}{(1+r)^{j-0.5}} \,,$$

or equivalently,

$$\mathrm{K} = \sqrt{1+r} \sum_{\mathrm{j}=1}^{\mathrm{N}} \frac{CF_j}{(1+r)^{\mathrm{j}}} \,.$$

Making the substitution,

$$CF_j = cK(1-s) + \delta_j Ks$$

and solving for c yields equation (1.4).

(1.4)

$$CRF = \frac{r(1+r)^N}{(1-s)[(1+r)^N - 1]} \left\{ \frac{1}{\sqrt{1+r}} - s \sum_{j=1}^{N} \frac{\delta_j}{(1+r)^j} \right\}$$

Using the parameter values in Table 1-2, with a five year capital cost recovery period and straight line depreciation, equation (1.4) yields a CRF of 0.260798. With an initial capital investment of $1 million, the annual payment is $260,798. Table 1-4 shows the corresponding cash flow summary.

Table 1-4 Cash flow summary for 5 year, $1 million investment with half year convention

Service Year	1	2	3	4	5
Revenue	$260,798	$260,798	$260,798	$260,798	$260,798
Depreciation	$200,000	$200,000	$200,000	$200,000	$200,000
Tax Payment	$17,090	$17,090	$17,090	$17,090	$17,090
Return on Capital Investment	$41,711	$67,959	$52,992	$36,751	$19,126
Payback of Capital Investment	$201,997	$175,749	$190,716	$206,957	$224,582
Remaining Capital Investment	$798,003	$622,255	$431,539	$224,582	$0

The calculation of the values in Table 1-4 is identical to the corresponding values in Table 1-3 except that the year 1 return on investment reflects a half year period. The return on investment in year 1 is equal to the product of the capital investment and the half year rate of return $\sqrt{1+r}-1$. The cash flow summary shows that the revenue payment determined by the CRF is necessary and sufficient to pay the taxes associated with the revenue payment as well as the required return on and return of the capital investment.

Changing the depreciation assumption to 3 year MACRS produces a CRF of 0.254231. The MACRS depreciation factors are shown in Table 1-8. The lower CRF relative to the straight line depreciation example reflects the lower tax payment under MACRS due to the accelerated depreciation schedule. In years 1 and 2, the tax payment in Table 1-5 is negative due to the accelerated depreciation assumption.[8] The cash flow summary in Table 1-5 shows that the revenue payment determined by the CRF, using 3 year MACRS depreciation, is at the necessary and sufficient level to provide for the taxes associated with the revenue payment as well as the required return on and return of the capital investment.

Table 1-5 Cash flow summary for 5 year, $1 million investment with 3 year MACRS

Service Year	1	2	3	4	5
Revenue	$254,231	$254,231	$254,231	$254,231	$254,231
Depreciation	$333,300	$444,500	$148,100	$74,100	$0
Tax Payment	($22,226)	($53,485)	$29,833	$50,635	$71,464
Return on Capital Investment	$41,711	$65,170	$44,515	$29,195	$14,343
Payback of Capital Investment	$234,747	$242,546	$179,883	$174,401	$168,424
Remaining Capital Investment	$765,253	$522,708	$342,825	$168,424	$0

The depreciation assumption has a significant impact on the CRF level. Generally, the faster the capital is depreciated for tax purposes, the lower the CRF. The Tax Cuts and Jobs Act (TCJA), signed into law on December 22, 2017 included bonus depreciation rates applicable to capital investments placed in service after September 27, 2017.[9] [10] Capital investments placed into service after September 27, 2017 and before January 1, 2023, are eligible for 100 percent bonus depreciation.[11]

8 It is assumed that the capital investor would use the negative tax liability from this project as an offset against the tax liability resulting from other revenue.

9 Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017).

10 26 U.S. Code §11(b)

11 Bonus depreciation is 100 percent for capital investments placed in service after September 27, 2017 and before January 1, 2023. Bonus depreciation is 80 percent for capital investments placed in service after December 31, 2022 and before January 1, 2024, and the bonus depreciation level is reduced by 20

Assuming 100 percent bonus depreciation results in a CRF of 0.247523. The corresponding cash flow summary is given in Table 1-6. The CRF for straight line depreciation for a five year cost recovery period is 5.3 percent higher than the CRF corresponding to 100 percent bonus depreciation.

Table 1-6 Cash flow summary for 5 year, $1 million investment with bonus depreciation

Service Year	1	2	3	4	5
Revenue	$247,523	$247,523	$247,523	$247,523	$247,523
Depreciation	$1,000,000	$0	$0	$0	$0
Tax Payment	($211,521)	$69,579	$69,579	$69,579	$69,579
Return on Capital Investment	$41,711	$49,621	$38,692	$26,834	$13,965
Payback of Capital Investment	$417,334	$128,324	$139,252	$151,111	$163,980
Remaining Capital Investment	$582,666	$454,343	$315,091	$163,980	$0

The CRF for a capital investment with a 20 year recovery period is 0.103149 and the corresponding cash flow summary is given in Table 1-7 for a capital investment totaling $10,000,000.

percent for each subsequent year through 2026. Capital investments placed in service after December 31, 2026 are not eligible for bonus depreciation. See 26 U.S. Code §168(k)(6)(A).

Table 1-7 Cash flow summary for 20 year, $10 million investment with bonus depreciation

Service Year	Revenue	Depreciation	Tax Payment	Return on Capital Investment	Payback of Capital Investment	Remaining Capital Investment
1	$1,031,492	$10,000,000	($2,521,048)	$417,109	$3,135,431	$6,864,569
2	$1,031,492	$0	$289,952	$584,597	$156,943	$6,707,626
3	$1,031,492	$0	$289,952	$571,231	$170,308	$6,537,318
4	$1,031,492	$0	$289,952	$556,728	$184,812	$6,352,506
5	$1,031,492	$0	$289,952	$540,989	$200,551	$6,151,955
6	$1,031,492	$0	$289,952	$523,910	$217,630	$5,934,325
7	$1,031,492	$0	$289,952	$505,376	$236,164	$5,698,161
8	$1,031,492	$0	$289,952	$485,264	$256,276	$5,441,886
9	$1,031,492	$0	$289,952	$463,439	$278,101	$5,163,785
10	$1,031,492	$0	$289,952	$439,756	$301,784	$4,862,001
11	$1,031,492	$0	$289,952	$414,055	$327,484	$4,534,517
12	$1,031,492	$0	$289,952	$386,166	$355,373	$4,179,143
13	$1,031,492	$0	$289,952	$355,902	$385,638	$3,793,505
14	$1,031,492	$0	$289,952	$323,061	$418,479	$3,375,026
15	$1,031,492	$0	$289,952	$287,422	$454,117	$2,920,909
16	$1,031,492	$0	$289,952	$248,749	$492,791	$2,428,118
17	$1,031,492	$0	$289,952	$206,782	$534,758	$1,893,361
18	$1,031,492	$0	$289,952	$161,241	$580,298	$1,313,062
19	$1,031,492	$0	$289,952	$111,822	$629,717	$683,345
20	$1,031,492	$0	$289,952	$58,195	$683,345	$0

In each example, the annual revenue payment, equal to the product of the capital investment and the CRF obtained from equation (1.4) is the necessary and sufficient revenue amount to cover the tax liability and the return on and return of the investment capital. This observation is generalized in the following proposition.

Proposition 1.2. The CRF given by equation (1.4) is the unique value, assuming a WACC capital budgeting model with the half year convention, for which the resulting annual revenue payment is necessary and sufficient, over the term of the investment, to pay the annual tax liability and the return on and return of the capital investment.

Table 1-8 Modified Accelerated Cost Recovery System (MACRS) with half year convention[12]

Year	3 year Depreciation Factors	5 year Depreciation Factors	10 year Depreciation Factors	15 year Depreciation Factors	20 year Depreciation Factors
1	33.33%	20.00%	10.00%	5.00%	3.750%
2	44.45%	32.00%	18.00%	9.50%	7.219%
3	14.81%	19.20%	14.40%	8.55%	6.677%
4	7.41%	11.52%	11.52%	7.70%	6.177%
5		11.52%	9.22%	6.93%	5.713%
6		5.76%	7.37%	6.23%	5.285%
7			6.55%	5.90%	4.888%
8			6.55%	5.90%	4.522%
9			6.56%	5.91%	4.462%
10			6.55%	5.90%	4.461%
11			3.28%	5.91%	4.462%
12				5.90%	4.461%
13				5.91%	4.462%
14				5.90%	4.461%
15				5.91%	4.462%
16				2.95%	4.461%
17					4.462%
18					4.461%
19					4.462%
20					4.461%
21					2.231%

1.3 Proof of Proposition 1.2

Proposition 1.2. The CRF given by equation (1.4) is the unique value, assuming a WACC capital budgeting model with the half year convention, for which the resulting annual revenue payment is necessary and sufficient, over the term of the investment, to pay the annual tax liability and the return on and return of the capital investment.

Proof. K_0 is the initial capital invested and K_j, $j \geq 1$, represents the capital investment remaining at the midpoint of cost recovery year j. K_1 is the remaining capital investment at the midpoint of year 1 after using the year 1 revenue net of taxes and return on investment, as a payback to investors. The proposition states that the CRF in equation (1.4) is the unique value that will result in $K_N = 0$. Representing the CRF in equation (1.4) as c, the year 1 revenue net of taxes and return on investment is

[12] See Appendix A, Table A-1, IRS Publication 946, United States Department of Treasury (2020).

$$cK_0(1-s)+\delta_1K_0s-K_0\left(\sqrt{1+r}-1\right).$$

The rate of return on the investment reflects a half year of return due to the half year convention. The equity investment that remains at the midpoint of year 1 is

$$K_1=K_0-\left(cK_0(1-s)+\delta_1K_0s-K_0\left(\sqrt{1+r}-1\right)\right)$$

$$=K_0\sqrt{1+r}-cK_0(1-s)-\delta_1K_0s.$$

The year 2 revenue net of taxes and return on investment is

$$cK_0(1-s)+\delta_2K_0s-rK_1$$

and the capital investment that remains at the midpoint of year 2 is

$$K_2\ =K_1(1+r)-cK_0(1-s)-\delta_2K_0s\,.$$

Substitution for K_1 yields

$$K_2\ =K_0(1+r)^{3/2}-cK_0(1-s)[(1+r)+1]-[\delta_1(1+r)+\delta_2]K_0s\,.$$

Repeating this process through the end of the cost recovery period yields

(1.5)

$$K_N=K_0(1+r)^{N-1/2}-cK_0(1-s)\sum_{j=1}^{N}(1+r)^{j-1}-K_0s\sum_{j=1}^{N}\delta_j(1+r)^{N-j}\,.$$

Equation (1.2) with $H=1$, $W=N$ and $v=1+r$ gives

$$\sum_{j=1}^{N}(1+r)^{j-1}=\frac{1}{1+r}\sum_{j=1}^{N}(1+r)^{j}=\frac{(1+r)^N-1}{r}.$$

Replacing the first summation in equation (1.5) yields

(1.6)

$$K_N=K_0(1+r)^{N-1/2}-cK_0(1-s)\left(\frac{(1+r)^N-1}{r}\right)-K_0s\sum_{j=1}^{N}\delta_j(1+r)^{N-j}\,.$$

Replacing c in (1.6) with the CRF formula in (1.4) results in $K_N=0$. Equation (1.6) also establishes the uniqueness of the CRF. If there are two CRF values, for instance c_1 and c_2, satisfying the proposition, then each will produce $K_N=0$ and one can quickly deduce from the equation (1.6) that $c_1=c_2$.

Exhibit No. IMM-0004
CRF and Annual Payment – Capital reduced for ITC

Recovery Period (years)	20	25	30	35	40
Reactive Capital Cost per Company Testimony[1]	$35,711,759	$35,711,759	$35,711,759	$35,711,759	$35,711,759
Investment Tax Credit[2]	$9,320,769	$9,320,769	$9,320,769	$9,320,769	$9,320,769
Capital Cost to be recovered through Reactive Compensation	$26,390,990	$26,390,990	$26,390,990	$26,390,990	$26,390,990
Capital Recovery Factor[3] [4]	0.094826	0.086377	0.081254	0.077982	0.075822
IMM Annual Payment for Capital Cost Recovery	$2,502,551	$2,279,575	$2,144,386	$2,058,028	$2,001,010
Company Annual Payment for Capital Cost Recovery[5]	$3,500,381	$3,500,381	$3,500,381	$3,500,381	$3,500,381
Annual Payment in excess of IMM Annual Payment	$997,830	$1,220,806	$1,355,995	$1,442,353	$1,499,371

[1] See Exhibit No. BPS-3, Schedule 1, Attachment C.

[2] Assumes 30 percent ITC, applicable to 87 percent of capital cost.

[3] Calculated using equation (1.4) in the CRF Technical Reference.

[4] Assumes 80 percent bonus depreciation.

[5] See Exhibit No. BPS-3, Schedule 1, Attachment C, ARR less reactive fixed operating expense.

Exhibit No. IMM-0005

CRF and Annual Payment – Capital not reduced for ITC

Recovery Period (years)	20	25	30	35	40
Reactive Capital Cost per Company Testimony[1]	$35,711,759	$35,711,759	$35,711,759	$35,711,759	$35,711,759
Investment Tax Credit[2]	$0	$0	$0	$0	$0
Capital Cost to be recovered through Reactive Compensation	$35,711,759	$35,711,759	$35,711,759	$35,711,759	$35,711,759
Capital Recovery Factor[3 4]	0.094826	0.086377	0.081254	0.077982	0.075822
IMM Annual Payment for Capital Cost Recovery	$3,386,402	$3,084,676	$2,901,740	$2,784,882	$2,707,726
Company Annual Payment for Capital Cost Recovery[5]	$3,500,381	$3,500,381	$3,500,381	$3,500,381	$3,500,381
Annual Payment in excess of IMM Annual Payment	$113,979	$415,705	$598,641	$715,499	$792,655

[1] See Exhibit No. BPS-3, Schedule 1, Attachment C.

[2] Assumes a reduction for ITC is not applicable.

[3] Calculated using equation (1.4) in the CRF Technical Reference.

[4] Assumes 80 percent bonus depreciation.

[5] See Exhibit No. BPS-3, Schedule 1, Attachment C, ARR less reactive fixed operating expense.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Big Plain Solar, LLC	))))	Docket Nos. EL23-78-000, ER23-1736-000

DECLARATION

JOSEPH E. BOWRING states that I prepared the affidavit to which this declaration is attached with the assistance of the staff of Monitoring Analytics, LLC, and that the statements contained therein are true and correct to the best of my knowledge and belief. Monitoring Analytics, LLC, is acting in its capacity as the Independent Market Monitor for PJM.

Pursuant to Rule 2005(b)(3) (18 CFR § 385.2005(b)(3), citing 28 U.S.C. § 1746), I further state under penalty of perjury that the foregoing is true and correct.

Executed on January 29, 2024.

Joseph E. Bowring

Attachment
Exhibit Nos. IMM-0001–0004

Bowring Affidavit
and Supporting Exhibits