continued operation of the projects on Atlantic salmon, Atlantic sturgeon, and shortnose sturgeon, and the designated critical habitat for Atlantic salmon and Atlantic sturgeon.

**The NEPA Process and the EIS**

The EIS issued by the Commission will discuss environmental effects that could occur as a result of the proposed Shawmut Project relicensing, and amending the licenses for the Shawmut, Lockwood, Hydro-Kennebec, and Weston Projects to include the measures contained in the Interim and Final Plans for the protection of ESA-listed Atlantic salmon, Atlantic sturgeon, and shortnose sturgeon. The EIS will address environmental effects associated with these proposed actions under the following general resource areas:

- Geology and soils
- water quality
- aquatic resources
- terrestrial resources
- threatened and endangered species
- recreation
- land use
- aesthetic resources
- socioeconomics
- cultural resources
- air quality and noise
- developmental resources

Your comments will help Commission staff identify and focus on the issues that might have an effect on the human environment and potentially eliminate others from further study and discussion in the EIS.

The EIS will present Commission staff's independent analysis of the issues. Staff will prepare a draft EIS which will be issued for public comment. Commission staff will consider all timely comments received during the comment period on the draft EIS and revise the document, as necessary, before issuing a final EIS. The draft and final EIS will be available in electronic format in the public record through eLibrary. If eSubscribed, you will receive email notification when environmental documents are issued.

**Expected Environmental Impacts**

Based on the previous pre-filing scoping process for the Shawmut Project, staff's analysis in the Shawmut Project DEA, Brookfield's proposed Interim and Final Plans and the comments received on the record for each of these proceedings, Commission staff has identified the following major environmental impacts of the proposed action that will be evaluated in the EIS: (1) Effects of construction of proposed fish passage facilities on water quality and aquatic habitat; (2) effects of operation of existing and proposed fish passage facilities on upstream and downstream migration of diadromous fish populations, including threatened and endangered species and critical habitat; and (3) effects of proposed fish passage facility construction on cultural resources at the projects.

**Alternatives Under Consideration**

As part of our review in the EIS, Commission staff will consider all reasonable alternatives, which include: Alternatives that are technically and economically feasible, meet the purpose and need for the proposed action, and meet the goals of the applicant.[3] Alternatives that do not meet these requirements will be summarized and dismissed from further consideration in the EIS. Staff will also consider the no-action alternative. With this notice, we ask commenters to identify potential alternatives for consideration.

**Schedule for Environmental Review**

This scoping notice identifies Commission staff's planned schedule for completion of the draft and final EIS for the proposals.

Issuance of Notice of Availability of the draft EIS—August 2022

Issuance of Notice of Availability of the final EIS—February 2023

If a schedule change becomes necessary, an additional notice will be provided so that the relevant agencies are kept informed of the projects' progress. After the final EIS is issued, the Commission will make a decision on the proposals.

**Permits and Authorizations Required**

The table below lists the permits and authorizations that are anticipated to be required for the proposed actions. We note that this list may not be all-inclusive and does not preclude any required permits or authorizations if it is not listed here. Agencies with jurisdiction by law and/or special expertise may formally cooperate in the preparation of the Commission's EIS and may adopt the EIS to satisfy its NEPA responsibilities related to these actions. Agencies that would like to request cooperating agency status should follow the instructions for filing comments provided under the *Public Participation* section of this notice.

| Permit | Agency |
| --- | --- |
| Clean Water Act Section 401 Water Quality Certification | Maine Department of Environmental Protection. |
| Endangered Species Act Section 7 Consultation | National Marine Fisheries Service. |

**Additional Information**

Additional information about the project is available on the FERC website at *www.ferc.gov* using the eLibrary link. Click on the eLibrary link, click on ''General Search'' and enter the docket number in the ''Docket Number'' field, excluding the last three digits (*i.e.,* P–2322, P–2325, P–2574, and P–2611). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at *FercOnlineSupport@ferc.gov* or (866) 208–3676, or for TTY, contact (202) 502–8659. The eLibrary link also provides access to the texts of all formal documents issued by the Commission, such as orders, notices, and rulemakings.

If you have further questions you may also contact Marybeth Gay at *Marybeth.gay@ferc.gov,* or 202–502–6125, or Matt Cutlip at *Matt.Cutlip@ferc.gov,* or 503–552–2762.

Dated: November 23, 2021.

**Kimberly D. Bose,**

*Secretary.*

[FR Doc. 2021–26034 Filed 11–29–21; 8:45 am]

BILLING CODE 6717–01–P

[3] 40 CFR 1508.1(z)

**DEPARTMENT OF ENERGY**

**Federal Energy Regulatory Commission**

**[Docket No. RM22–2–000]**

## Reactive Power Capability Compensation

**AGENCY:** Federal Energy Regulatory Commission, Department of Energy.

**ACTION:** Notice of inquiry.

**SUMMARY:** The Federal Energy Regulatory Commission (Commission) is inviting comments on reactive power

capability compensation and market design.

**DATES:** Initial Comments are due January 31, 2022, and Reply Comments are due February 28, 2022.

**ADDRESSES:** Comments, identified by docket number, may be filed in the following ways:

• *Electronic Filing through http://www.ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.

• *Mail/Hand Delivery:* Those unable to file electronically may mail comments via the U.S. Postal Service to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426. Hand-delivered comments or comments sent via any other carrier should be delivered to: Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

*Instructions:* For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

**FOR FURTHER INFORMATION CONTACT:**

Noah Schlosser (Technical Information), Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–8356, *Noah.Schlosser@ferc.gov*

Neil Yallabandi (Legal Information), Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–8260, *Neil.Yallabandi@ferc.gov*

**SUPPLEMENTARY INFORMATION:**

1. The Federal Energy Regulatory Commission (Commission) is issuing this Notice of Inquiry (NOI) to seek comments on reactive power capability compensation and market design.

2. In an order issued in 2002,[1] the Commission recommended that all resources that have actual cost data and support documentation use the method employed in *American Electric Power Service Corporation* to establish a rate for the provision of reactive power.[2] Since the issuance of *AEP,* the electric markets and the generation resource mix have undergone significant change. For example, in 1999, when *AEP* issued, the majority of reactive power filings were made by synchronous resources that were owned by public utilities subject to the Uniform System of Accounts (USofA) and who annually submitted a FERC Form No. 1.[3] Today, the majority of the filings by entities seeking to establish a rate for reactive power capability compensation received at the Commission are made by owners of non-synchronous resources that produce reactive power using different types of equipment than used by synchronous resources. In addition, most filing entities (both synchronous and non-synchronous) received waivers of the requirement to maintain their accounts under the USofA rules and to file FERC Form No. 1 when they were granted market-based rate (MBR) authority under Order No. 697.[4] These changes have contributed, at least in part, to many such filings being set for hearing and settlement judge procedures.

3. In light of these developments, we seek comment on various issues that have arisen regarding reactive power capability compensation and market design.

## I. Background

### *A. Reactive Power and Regulation*

4. Almost all bulk electric power is generated, transported, and consumed in alternating current (AC) networks. Elements of AC systems supply and consume two kinds of power: Real power and reactive power. Real power accomplishes useful work (*e.g.,* runs motors and lights lamps). Reactive power supports the voltages that must be controlled for system reliability. At times, resources must either supply or consume reactive power for the transmission system to maintain voltage levels required to reliably supply real power from generation to load. Inadequate reactive power supply lowers voltage; as voltage drops, current must increase to maintain the power supplied, causing the lines to consume more reactive power and the voltage to drop further, eventually leading to reliability problems such as loss of transmission system stability and voltage collapse.[5]

5. In the Commission's *pro forma* LGIA, the power factor design criteria specify that, for synchronous resources, the ''Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection.''[6] For non-synchronous resources, the ''Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the high side of the generator substation.''[7]

6. Not only is reactive power necessary to operate the transmission system reliably, but it can also substantially improve the efficiency with which real power is delivered to customers. Increasing reactive power production at certain locations (usually near a load center) can sometimes alleviate transmission constraints and allow cheaper real power to be delivered into a load pocket.[8]

7. The rules for procuring reactive power can affect whether adequate reactive power supply is available, as well as whether the supply is procured efficiently from the most reliable and lowest-cost resources. This is readily apparent in the large portions of the United States where the transmission system is operated by regional transmission organizations (RTO) and independent system operators (ISO); these operators do not own generation and transmission facilities for producing and consuming reactive power and therefore must procure reactive power from others. But procurement rules also affect other parts of the United States where vertically integrated utilities operate the transmission system because reactive power capability is also available from independent companies.[9] Therefore, it is necessary to ensure that system operators, whether they are independent or vertically integrated, have adequate reactive power supplies at a just and reasonable rate.

8. The modern history of compensation for reactive power begins with the Commission's Order No. 888, its Open Access Rule, issued in April 1996.[10] In that order, the Commission

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[1] *WPS Westwood Generation, LLC,* 101 FERC ¶ 61,290, at P 14 (2002).

[2] *Am. Elec. Power Serv. Corp.,* Opinion No. 440, 88 FERC ¶ 61,141 (1999) (Opinion No. 440).

[3] The FERC Form No. 1 is a comprehensive financial and operating report submitted annually by Major electric utilities, licensees and others and used for electric accounting regulation, rate regulation, market oversight analysis, and planning audits. 18 CFR 141.1.

[4] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Order No. 697, 119 FERC ¶ 61,295, *clarified,* 121 FERC ¶ 61,260 (2007), *order on reh'g,* Order No. 697–A, 123 FERC ¶ 61,055, *clarified,* 124 FERC ¶ 61,055, *order on reh'g,* Order No. 697–B, 125 FERC ¶ 61,326 (2008), *order on reh'g,* Order No. 697–C, 127 FERC ¶ 61,284 (2009), *order on reh'g,* Order No. 697–D, 130 FERC ¶ 61,206 (2010), *aff'd sub nom. Mont. Consumer Counsel* v. *FERC,* 659 F.3d 910 (9th Cir. 2011).

[5] *Payment for Reactive Power,* Commission Staff Report, Docket No. AD14–7–000, at 4–6 (Apr. 22, 2014), *https://www.ferc.gov/sites/default/files/2020-05/04-11-14-reactive-power.pdf.*

[6] *See Pro Forma* LGIA, § 9.6.1.1.

[7] *Id.,* § 9.6.1.2.

[8] *Id.* at 7–8.

[9] *Id.* at 11–13.

[10] *Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,705–06 and 31,716–17 (1996) (cross-referenced at 75 FERC ¶ 61,080), Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC

concluded that ''reactive supply and voltage control from generation sources'' is one of six ancillary services that transmission providers must include in an open access transmission tariff.[11] The Commission noted that there are two approaches for supplying reactive power to control voltage: (1) Installing facilities as part of the transmission system and (2) using generation resources. The Commission concluded that the costs associated with the first approach would be recovered as part of the cost of basic transmission service and, thus, would not be a separate ancillary service. The second (using generation resources) would be considered a separate ancillary service and must be unbundled from basic transmission service. The Commission stated that, in the absence of proof that the generation seller lacks market power in providing reactive power, rates for this ancillary service should be cost-based and established as price caps, from which transmission providers may offer a discount.

9. In Opinion No. 440,[12] the Commission approved a method presented by American Electric Power Service Corp. (AEP), a vertically integrated utility, for allocating the costs of generator equipment between real power capability and reactive power capability, as well as the related operations and maintenance costs. AEP identified four components of a generation plant related to the production of reactive power: (1) The generator and its exciter, (2) the generator step-up transformer, (3) accessory electric equipment that supports the operation of the generator-exciter, and (4) the remaining total production investment required to provide real power and operate the exciter. Because these plant items produce both real and reactive power, AEP developed an allocation factor to sort the annual revenue requirements of these components between real and reactive power production. The factor for allocating to reactive power, developed by AEP, is $MVAR^2/MVA^2$, where MVAR is megavolt amperes reactive capability and MVA is megavolt amperes capability at a power factor of 1. Subsequently, the Commission indicated that all resources that have actual cost data and support should use AEP's methodology in seeking to recover reactive power capability costs pursuant to individual cost-based revenue requirements (hereinafter, the AEP Methodology).[13]

10. In Order No. 2003,[14] the Commission adopted standard large generator interconnection procedures and a standard agreement for the interconnection of large generation facilities (the *pro forma* Large Generator Interconnection Agreement (LGIA)), which included the requirement that interconnection customers maintain a power factor range of 0.95 leading to 0.95 lagging, unless the transmission provider has established a different power factor range.[15] Order No. 2003 required payment for reactive power to an interconnection customer only when the transmission provider requests the interconnection customer to operate its generating facility outside the established power factor range.[16] With respect to reactive power within the established power factor range, the Commission initially concluded that an 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.'' [17] In Order No. 2003–A, however, the Commission clarified that ''if the Transmission Provider pays its own or its affiliated generators for reactive power within the established range, it must also pay the Interconnection Customer.'' [18] Subsequently, in Order No. 2003–C, the Commission disagreed with commenters that reactive power capability compensation would result in a windfall to generators, explaining that reactive power is an important service.[19] Order No. 2003–A also exempted wind generators from maintaining the established power factor range.[20]

11. Order No. 661 established technical requirements for interconnecting large wind resources and maintained the exemption from providing reactive power, except where the transmission provider showed, through a system impact study, that reactive power capability was required to ensure safety or reliability.[21] In Order No. 2006,[22] the Commission adopted identical power factor and compensation requirements for small generating facilities (facilities having a capacity of no more than 20 MW) but exempted small wind generators from the reactive power requirement. In Order No. 827,[23] the Commission eliminated the exemptions for wind resources from the requirement to provide reactive power. As a result, all newly interconnecting non-synchronous generators were required to provide reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation as a condition of interconnection. Order No. 827 also clarified that the amount of reactive power required from non-synchronous resources should be proportionate to the actual (real) power output.[24] With respect to compensation, the Commission concluded that it did not have a sufficient record for determining a new methodology for non-synchronous generation reactive power compensation and stated that any non-synchronous resource seeking reactive power compensation would need to propose a method for calculating that compensation as part of its filing.[25]

*B. Approaches to Reactive Power Capability Compensation*

12. In RTOs/ISOs where transmission providers compensate for reactive power capability, the compensation is either (1) based on individual reactive power revenue requirements determined in cases for individual resources (or fleets [26] of resources) established pursuant to a cost-based methodology (*e.g.,* the AEP

¶ 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 relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (DC Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[11] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,705. The *pro forma* open access transmission tariff (OATT) includes six schedules that set forth the details pertaining to each ancillary service. The details concerning reactive power are included in Schedule 2 of the *pro forma* OATT. *Id.* at 31,960.

[12] *AEP,* Opinion No. 440, 88 FERC ¶ 61,141.

[13] *WPS Westwood Generation, LLC,* 101 FERC ¶ 61,290 at P 14; *FPL Energy Marcus Hook, L.P.,* 110 FERC ¶ 61,087, at P 16, *order on reh'g,* 111 FERC ¶ 61,168 (2005).

[14] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, 104 FERC ¶ 61,103 (2003), *order on reh'g,* Order No. 2003–A, 106 FERC ¶ 61,220, *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. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007).

[15] *Id.* P 542.

[16] *Id.* P 546.

[17] *Id.*

[18] Order No. 2003–A, 106 FERC ¶ 61,220 at P 416.

[19] Order No. 2003–C, 111 FERC ¶ 61,401 at P 42.

[20] Order No. 2003–A, 106 FERC ¶ 61,220 at P 34.

[21] *Interconnection for Wind Energy,* Order No. 661, 111 FERC ¶ 61,353, *order on reh'g,* Order No. 661–A, 113 FERC ¶ 61,254 (2005).

[22] *Standardization of Small Generator Interconnection Agreements and Procedures,* Order No. 2006, 111 FERC ¶ 61,220, *order on reh'g,* Order No. 2006–A, 113 FERC ¶ 61,195 (2005), *order granting clarification,* Order No. 2006–B, 116 FERC ¶ 61,046 (2006).

[23] *Reactive Power Requirements for Non-Synchronous Generation,* Order No. 827, 155 FERC ¶ 61,277, *order on clarification and reh'g,* 157 FERC ¶ 61,003 (2016).

[24] *Id.* P 49.

[25] *Id.* PP 47, 52.

[26] Fleet-based rate schedules consist of a single rate for multiple resources, sometimes developed over an extended period of time, which do not specify which resources are being compensated under the rate schedule.

Methodology) using the resource's MVAR capability or (2) paid on a flat per-MVAR region-wide basis based on testing for the maximum MVAR capability of the resource. Resources in PJM Interconnection, Inc. (PJM) and Midcontinent Independent System Operator, Inc. (MISO) generally use the AEP Methodology to set reactive power compensation on an individual resource basis, whereas resources in ISO New England Inc. (ISO-NE) and New York Independent System Operator, Inc. (NYISO) are compensated for reactive power under a flat rate described further below. Outside of these RTOs/ISOs, when transmission providers pay for the capability to provide reactive power within the standard power factor range, resources generally propose to use the AEP Methodology to set reactive power compensation on an individual resource basis.[27]

13. PJM and MISO compensate each resource owner with an amount equal to the resource owner's monthly reactive power capability service revenue requirement for reactive power capability, as accepted by the Commission. Although PJM and MISO both conduct regular reactive power capability testing,[28] because they compensate based on the reactive power revenue requirements on file with the Commission, they do not link the tested capability to compensation, and neither PJM nor MISO is required to notify the Commission when a resource fails to achieve its nameplate MVAR capability when tested.

14. ISO-NE and NYISO compensate resources for reactive power capability using a flat rate representing dollars per MVAR-year,[29] which is multiplied by the resource's tested reactive power capability.[30]

15. In ISO-NE, reactive power compensation is established by adding: (a) A flat rate for capacity costs designed to compensate for fixed capital costs related to providing reactive power; (b) a variable rate for lost opportunity costs; (c) a variable rate for energy consumed to produce reactive power; and (d) a variable rate for costs for the resource to come online or to increase its output above its economic loading point.[31] ISO-NE periodically adjusts the base flat rates for inflation.

16. The NYISO flat rate is based on the average cost-of-service in NYISO for providing leading and lagging reactive power.[32] In NYISO, the annual payment to qualified reactive power suppliers equals the product of the compensation rate and the sum of the lagging and the absolute value of the leading MVAR capacity [33] of the resource, as evidenced by the resource's tested reactive power capability. NYISO adjusts the base flat rates annually for inflation. In NYISO, only the flat rate portion is paid.[34]

## II. Discussion

17. Generation owners seeking compensation for reactive power capability in PJM, MISO, and non-RTO/ISO regions that compensate for reactive power capability based on the costs of individual resources or on a fleet-wide basis generally submit individual cost-of-service filings based on the AEP Methodology.[35] As explained above, the 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. Since the AEP Methodology was established in 1999, the electric industry has undergone significant changes, both in the generation resource mix and a general shift away from cost-of-service rates for generators selling into Commission-jurisdictional markets. Now, the majority of the reactive power filings submitted to the Commission are made by owners of non-synchronous resources that, relying on waivers granted by the Commission in conjunction with sellers obtaining MBR authority under Order No. 697, neither use the USofA nor file FERC Form No. 1. Because the AEP Methodology was designed based on the physical attributes of a synchronous resource and because of this lack of FERC Form No. 1 information for independent power producers (synchronous and non-synchronous alike), customers and the Commission have faced challenges in evaluating proposed reactive power rate schedules submitted pursuant to section 205 of the Federal Power Act (FPA), resulting in the majority of the filings being set for hearing and settlement procedures.

18. Furthermore, in PJM, several resources that have interconnected to the distribution system rather than the transmission system have still sought compensation from transmission operators for their reactive power capabilities.[36] Monitoring Analytics, LLC, the Independent Market Monitor

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[27] In addition, California Independent System Operator Corporation (CAISO); Southwest Power Pool, Inc. (SPP); and some non-RTO/ISO transmission operators (*e.g.,* Bonneville Power Administration, Arizona Public Service Company, Southern Companies) do not pay for reactive power capability.

[28] Under Schedule 2 of MISO's tariff, MISO's technical requirements dictate that within the past five years the generation resource meets the testing requirements for voltage control capability required by the Regional Reliability Council where the generation resource is located. *See* MISO, FERC Electric Tariff, Sched. 2, § II.B.3 (38.0.0). In PJM, resource owners are required to test 20% of their resources that receive reactive power capability compensation for reactive power capability annually, totaling 100% of such facilities over a 66 month period. However, individual resources that (1) have nameplate ratings below 20 MVA, (2) form part of aggregate generating facilities with nameplate ratings below 75 MVA, or (3) are not directly connected to the Bulk Electric System are exempt from these testing requirements. *See* PJM Manual 14D (Generator Operational Requirements), attach. E § E.2.

[29] Both ISO-NE and NYISO proposed their respective reactive power capability compensation mechanisms pursuant to section 205 filings. *See* *ISO New England Inc.,* 122 FERC ¶ 61,056, at P 1 (2008) (settling, in part, for a new flat rate in $/kVAR-yr). Note that, although NYISO also has a fixed rate for reactive power capability compensation, NYISO proposed the approach pursuant to an FPA section 205 filing, with stakeholder support. *N.Y. Indep. Sys. Operator, Inc.,* Docket No. ER02–617–000 (Feb. 5, 2002) (delegated order accepting NYISO's amended Rate Schedule 2 of the Market Administration and Control Area Services Tariff).

[30] ISO-NE, Transmission, Markets and Services Tariff, Schedule 2—Reactive Supply and Voltage Control Service (10.0.0); NYISO, NYISO Market Administration and Control Area Services Tariff (MST), Section 15.2, Rate Schedule 2—Payments for Supplying Voltage Supply (11.0.0). ISO-NE and NYISO conduct reactive power capability testing at least once every five years and annually, respectively. *See* ISO-NE, Transmission, Markets and Services Tariff, Schedule 2, § IV.A.12(a); NYISO, NYISO MST, Section 15.2.2.1, Annual Payment for Voltage Support Service; NYISO, *Ancillary Services Manual,* § 3.6 (Oct. 2021).

[31] *See, e.g., Me. Pub. Utils. Comm'n* v. *ISO New England Inc.,* 126 FERC ¶ 61,090, at P 6 (2009).

[32] NYISO, Deficiency Letter Response, Docket No. ER15–1042–001, at 1 (filed Apr. 30, 2015). NYISO explained that the $2,592/MVAR flat rate was calculated ''by dividing the total VSS [Voltage Support Service] program compensation paid to qualified VSS Suppliers in 2012 by the total lagging and leading reactive power capability of all qualified VSS Suppliers in 2012.'' Voltage Support Service is the ability to produce or absorb reactive power and the ability to maintain a specific voltage level under both steady-state and post-contingency operating conditions subject to the limitations of the resource's stated reactive capability.

[33] Reactive power capability is measured in MVAR. A resource's lagging reactive power capability indicates its ability to produce reactive power, and its leading reactive power capability indicates its ability to consume reactive power.

[34] Like the AEP Methodology, these flat rates are intended to compensate resources for the costs of reactive power capability.

[35] *Am. Elec. Power Serv. Corp.,* 80 FERC ¶ 63,006, at 65,071 (1997), *aff'd in part, rev'd in part,* Opinion No. 440, 88 FERC ¶ 61,141 at 61,437 (establishing the AEP Methodology); *see also WPS Westwood Generation, L.L.C.,* 101 FERC ¶ 61,290 at P 14 (recommending that all resources seeking to recover reactive power capability costs pursuant to individual cost-based revenue requirements use the AEP Methodology); *Dynegy Midwest Generation, Inc.,* Opinion No. 498, 121 FERC ¶ 61,025, at P 71 (2007), *order on reh'g,* 125 FERC ¶ 61,280 (2008) (discussing the AEP Methodology and recovery of heating losses).

[36] *See, e.g., Ingenco Wholesale Power, LLC,* 173 FERC ¶ 61,247 (2020) (*Ingenco*); *Whitetail Solar 3, LLC,* 173 FERC ¶ 61,288 (2020); *Whitetail Solar 2, LLC,* 174 FERC ¶ 61,238 (2021); *Elk Hill Solar 2, LLC,* 175 FERC ¶ 61,188 (2021); *Mechanicsville Solar, LLC,* 176 FERC ¶ 61,076 (2021).

for PJM (PJM Market Monitor), has argued that these resources are not technically capable of providing reactive power capability service consistent with Schedule 2 of PJM's tariff. Furthermore, it is unclear whether all such distribution-connected resources are technically capable of providing their full reactive power capability to the transmission system such that they are properly compensated through the applicable transmission rate schedules.[37]

19. Due to the aforementioned differences in the generation resource mix and divergent reporting requirements between market-based and cost-based sellers since the time when the AEP Methodology was established, the Commission seeks to examine whether the current regime for reactive power capability compensation requires revisions to ensure that payments for reactive power capability accurately reflect the costs associated with reactive power capability.

*A. Issues With AEP Methodology-Based Reactive Power Compensation*

20. We wish to explore several potential issues with reactive power capability compensation based on the AEP Methodology. These include the failure to account for the degradation of a resource's reactive power capability over time, any difficulties associated with applying the AEP Methodology to non-synchronous resources, any difficulty in verifying the revenue requirements proposed by owners of resources that have been granted waiver of certain accounting and reporting requirements, and any potential overcompensation in PJM stemming from the reactive power offset used in the PJM capacity market.[38]

1. Degradation

21. Although the Commission has established that resources that seek reactive power capability compensation under the AEP Methodology are required to submit test reports of their reactive power capability that support the company's proposed level of reactive power capability for which the company is seeking a proposed reactive power revenue requirement,[39] the AEP Methodology does not account for the fact that a resource's reactive power capability may degrade. As a result, over time the reactive power revenue requirement originally established under the AEP Methodology may no longer reflect the actual reactive power capability of the associated resource(s). However, unless a resource voluntarily files to revise its Commission-accepted revenue requirement or is otherwise required to do so under an applicable tariff, it will receive the same revenue over the course of its life, regardless of whether it maintains the capability to produce its stated power factor at its full real power capacity, which it supported with test reports at the time of its filing before the Commission. Furthermore, it can be difficult for the Commission to determine if the test reports accurately reflect the reactive power capability of the resource, particularly when the data the resource submits may be incomplete.[40]

2. Accounting and Ratemaking Issues Related to Non-Synchronous Resources

22. A lack of accounting and ratemaking guidance for non-synchronous resources under the AEP Methodology has contributed to litigation over reactive power compensation.[41] As noted above, the AEP Methodology was originally developed to determine the cost-of-service for reactive power production equipment owned by cost-of-service-regulated sellers and intended solely for synchronous resources. When compared to synchronous resources, non-synchronous resources have different physical processes and electric plant that is utilized in reactive power production. For example, relevant components of producing and controlling reactive power for synchronous resources include generator-exciters, step-up transformers, and accessory electric equipment. In contrast, non-synchronous resources may be capable of producing reactive power using only inverters.[42] As a result, when non-synchronous resources propose reactive power revenue requirements based on the AEP Methodology, they generally propose to populate AEP Methodology cost categories with equipment different from those used by synchronous resources.

23. For example, although the original AEP Methodology did not contemplate inclusion of a collection system as equipment necessary for production of reactive power, applicants have claimed that the collection system is comparable to the isolated phase bus of a synchronous facility, which is considered part of accessory electric equipment costs for synchronous resources. The isolated phase bus of a synchronous resource carries current between a synchronous resource and its step-up transformer. An isolated phase bus may be several feet in length, whereas a collection system for a non-synchronous resource may exceed a mile in length. The typical collection system in a non-synchronous resource uses multiple distribution voltage lines in a radial configuration to connect the power from the wind turbines or solar panels back to a central point, and the long length of the collector system lines causes reactive power losses. In comparison, the enclosed conductors of an isolated phase bus are short in length, thus causing much smaller reactive power losses, and provide fault protection between the synchronous resource and the step-up transformer. Due to these differences, the collection system of a non-synchronous resource generally represents a significantly higher proportion of the resource's total investment cost than the isolated phase bus represents for synchronous resources. Thus, non-synchronous resources' interpretation of the AEP Methodology under this approach increases the annual revenue requirement for those resources on a relative basis as compared to the annual revenue requirements for synchronous resources. The Commission has yet to formally address any difference in cost structures across generation types for reactive power compensation under the AEP Methodology.

24. Furthermore, the Commission's USofA does not include accounts that clearly accommodate non-hydro non-synchronous resources and associated operation and maintenance expenses. The Commission recently issued a separate NOI seeking input on whether

[37] *See infra* Section II.C.

[38] *See infra* notes 40–41, 47.

[39] The Commission required all resources to submit test reports when seeking a reactive power revenue requirement in *Wabash Valley Power Ass'n, Inc.,* 154 FERC ¶ 61,245, at P 29 (2016); *Wabash Valley Power Ass'n, Inc.,* 154 FERC ¶ 61,246, at P 28 (2016) (together, *Wabash*). The Commission also reiterated ''that revenue requirements established pursuant to Schedule 2 of the *pro forma* Open Access Transmission Tariff . . . are based on a particular level of reactive power capability for a particular generating unit or group of units'' and ''should reflect'' the present circumstances of the unit. *See Wabash,* 154 FERC ¶ 61,245 at P 28; 154 FERC ¶ 61,246 at P 27.

[40] The test report data does not always support the revenue requirement, and a resource's test reports are one of the issues often set for hearing and settlement procedures. *See, e.g., Talen Energy Mktg., LLC,* 155 FERC ¶ 61,297, at P 9 (2016); *Dynegy Lee II, LLC,* 161 FERC ¶ 61,016, at P 16 (2017); *Buckeye Power, Inc.,* 162 FERC ¶ 61,145, at P 10 (2018); *Ingenco,* 173 FERC ¶ 61,247 at P 30.

[41] *See Locke Lord LLP,* 174 FERC ¶ 61,033 (2021).

[42] Typically, inverter-based resources will shut down without sufficient power supply; however, if configured to do so, some inverter-based resources can produce reactive power without real power. *E.g.,* North American Electric Reliability Corporation, *Reliability Guideline—BPS-Connected Inverter-Based Resource Performance* at 34 (Sept. 2018), *https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.*

to create new accounts to accommodate these resources, how to modify FERC Form No. 1 to reflect any new accounts, and the rate setting implications, including for reactive power, of these potential accounting and reporting changes.[43]

3. Evidentiary Support

25. The AEP Methodology originally contemplated the use of USofA accounting structures and the sworn and attested-to accounting entries in the FERC Form No. 1 to support the proposed reactive power rates. This reliance enables resources to develop a cost-of-service rate that is verifiable by Commission staff and parties. However, the vast majority of resource owners currently applying for reactive power compensation reflecting the AEP Methodology received waivers of the Commission's accounting and reporting requirements when they were granted MBR authority under Order No. 697, meaning they do not submit the FERC Form No. 1, nor are they required to track their costs consistent with USofA accounting.[44] Thus, when resources that have been granted these waivers propose revenue requirements using the AEP Methodology, it is difficult for the Commission and affected customers to easily verify that the proposed rates accurately reflect the AEP Methodology.

4. Market-Based Compensation and Potential Overcompensation in PJM

26. The PJM Market Monitor has argued for some time that the best approach to reactive power compensation in PJM is through the capacity market rather than compensation through a separate cost-of-service construct as currently provided for under Schedule 2 of the PJM Tariff.[45] The PJM Market Monitor contends that cost-of-service compensation for reactive power capability is an anachronistic approach that predates the introduction of wholesale power markets and is unnecessary in light of potential compensation through the PJM markets. The PJM Market Monitor states that generating resources are required to have reactive capability to receive interconnection service. The PJM Market Monitor argues that Schedule 2 should be eliminated from the PJM tariff and PJM should rely on the capacity markets to ensure resource adequacy, including the capability to provide real power and reactive power at the lowest possible cost. More specifically, under the PJM Market Monitor's approach, if PJM's Schedule 2 were eliminated entirely, the gross costs of the entire plant, including any costs associated with the production of reactive power, would be included in the gross Cost of New Entry (CONE) and the generic offset for reactive power capability service compensation[46] would no longer be used to calculate Net CONE.

27. The PJM Market Monitor alternatively argues that, if PJM retains Schedule 2, Schedule 2 should be revised to avoid the potential overpayment for reactive power capability.[47] The PJM Market Monitor explains that the E&AS Offset associated with the reference resource in the capacity market is assumed to recover $2,199/MW-year in reactive power payments. The PJM Market Monitor states that, as a result of the offset rules, reactive power capability rates of up to $2,199/MW-year, do not result in double recovery for reactive power capability. On the other hand, the PJM Market Monitor contends that any separate reactive power capability payments through Schedule 2 that exceed $2,199/MW-year result in overcompensation as such costs can and should be recovered through the capacity market. In short, the PJM Market Monitor contends that when the market design allows for the recovery of specific costs for reactive power capability, it is inappropriate to also include those costs in a separate cost-of-service rate.

5. Questions Regarding AEP Methodology-Based Compensation

28. Given the backdrop of the issues discussed herein, we wish to explore in this NOI, whether the AEP Methodology remains a just and reasonable approach to determining reactive power revenue requirements in all circumstances. We encourage comments regarding the topics broadly discussed above. The following questions are designed to identify potential modifications to the AEP Methodology and related market designs and reporting requirements necessary to ensure just and reasonable rates for reactive power capability compensation. Commenters need not answer every question enumerated below.

a. Does compensating resources based on their costs of investment in reactive power capability continue to be the appropriate basis for reactive power capability compensation? Why or why not?

i. If so, does the AEP Methodology accurately reflect a resource's investment costs? Why or why not? To the extent your answer depends on the type of resource, please be specific.

b. What is the appropriate time period for compensation from a rate developed under the AEP Methodology? Should payments be limited based on the useful lives of the plant at issue? Why or why not?

c. As noted earlier, the power factor design criteria in the Commission's *pro forma* LGIA specify that the Large Generating Facility should be designed to maintain a composite power delivery at *continuous* rated power output, either at the Point of Interconnection for synchronous resources or at the high side of the generator substation for non-synchronous resources. Given this, when a resource conducts testing to demonstrate its reactive power capability, over what minimum amount

[43] *See Accounting and Reporting Treatment of Certain Renewable Energy Assets,* 174 FERC ¶ 61,032, at P 3 (2021) (citations omitted) (''Recently, parties have expressed disagreement regarding which Other Production accounts should be used to book non-hydro renewable assets. In Docket No. AC20–103, the Commission received a request for confirmation that the costs of certain wind and solar generating equipment are properly booked to the Other Production Accounts 343 (Prime Movers), 344 (Generators), and 345 (Accessory Electric Equipment). In that proceeding, commenters argued that the proposal booked an inappropriate amount of costs to Account 345, which are included in reactive power rates pursuant to the AEP Methodology. Commenters, including the Edison Electric Institute, suggested that the Commission consider creating new accounts for wind, solar, and other non-hydro renewables to resolve this issue.'').

[44] Per Order No. 697, the Commission grants MBR sellers waiver of the accounting and reporting requirements in its approval of initial applications for MBR authority.

[45] *See, e.g.,* PJM Market Monitor, Comments, Docket No. AD16–17–000, at 1, 6–10 (filed Aug. 1, 2016) (detailing the PJM Market Monitor's view that reactive capability costs can—and should—be recovered through PJM's capacity market instead of under a cost-of-service paradigm); Monitoring Analytics, 2020 State of the Market Report for PJM at 523, *https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020.shtml* (describing the PJM Market Monitor's position and recommended improvements).

[46] The Energy and Ancillary Services Offset (E&AS Offset) is used to calculate Net CONE in the PJM capacity market and it includes a revenue offset of $2,199/MW-year to reflect the average annual reactive power revenue for combustion turbines from 2005 through 2007, based on the actual costs reported to the Commission in reactive power capability service filings of combustion turbines. The result of this offset is that, conceptually, the cost of reactive capability is not part of Net CONE.

[47] *See, e.g.,* PJM Market Monitor, Comments, Docket No. AD16–17–000, at 8, 10 (filed Aug. 1, 2016) (explaining that ''[i]f revenues for reactive capacity were removed from the Net Energy and Ancillary Services Revenue Offset, then the fixed costs for investment in reactive capability would be recoverable through the capacity market,'' obviating the need for separate cost-of-service reactive power rates); PJM Market Monitor, Brief on Exceptions, Docket No. ER17–1821–002, at 3–16 (filed June 12, 2019) (discussing the PJM Market Monitor's concerns about what it termed a ''hybrid of market-based rates and cost of service rates''); PJM Market Monitor, Rehearing Request, Docket No. ER17–1821–005, at 3–5 (filed Apr. 30, 2021) (addressing issues regarding the E&AS Offset and a generator's proposed reactive power rates).

of time should a resource be required to maintain its maximum real power output while operating across its claimed reactive power factor range? Please specify to which type(s) of resource your proposed minimum time period corresponds.

i. The Commission has found that, to the extent the resource has established that it is able to produce reactive power up to its nameplate capability, a resource may use up to its nameplate power factor in calculating its reactive power revenue requirements.[48] Is there any reason for the Commission to believe that the nameplate capability aspect of calculating reactive power revenue requirements should be revised in order to produce a more accurate result? Why or why not? If so, in what manner (for example, should the power factor range identified in the interconnection agreement be considered)?

d. Many resources have an interconnection agreement in which reactive power requirements are addressed; however, to the extent that reactive power capability requirements are not addressed in a resource's interconnection agreement and a resource seeks compensation for supplying reactive power capability, how should the Commission address this? For example, should the Commission require that the resource and its transmission provider propose updates or additions to the interconnection agreement to specify the resource's reactive power capability requirements as a condition of establishing or maintaining a reactive power revenue requirement or should other methods be used in this regard?

e. Reactive power filings set for hearing and settlement judge procedures often do not have active intervening parties other than the market monitor and RTO/ISO. Why do other parties not participate more in these proceedings?

a. Degradation

f. How does a resource's reactive power capability degrade over time? Does the degradation follow a predictable pattern over a certain period of time? Does this answer vary depending on the generation type, real power capacity, and/or other aspects of a particular resource? If so, how?

i. Should resources receiving reactive power capability compensation undergo periodic reactive power capability testing to demonstrate that their reactive power capability compensation remains accurate?

1. If so, how frequently should this testing be performed?

2. Should the frequency of testing be influenced by other factors, including the generation type, real power capacity, and/or other aspects of a particular resource?

3. Is there a period after a new resource begins operating during which testing is unnecessary? If so, what is the appropriate length of this period and why? Please clarify which type of resource(s) this period should apply to and why.

4. Should reactive power capability compensation in all cases be linked to tested capability? If not, why not? If so, how? And, if so, should test results be updated and how frequently?

g. Should the AEP Methodology be modified to account for reactive power capability degradation over the lifetime of the resource and, if so, how?

i. If the Commission makes such a modification, should the revised methodology only consider the resource's most recent reactive power capability testing results, or should the Commission incorporate degradation curves or other processes to estimate continued degradation between tests? If using degradation curves, should this methodology vary by resource type? If so, how? Should a resource have the opportunity to rebut the application of a degradation curve if it can demonstrate that its test results exceed the estimate derived from a degradation curve?

ii. Should the Commission adopt a standard minimum testing frequency for resources that receive reactive power capability compensation? If not, why not? If so, what time period should the minimum frequency be (*e.g.,* testing required annually, biannually, every five years, etc.)? Please indicate to which type(s) of resources your proposed minimum frequency corresponds.

h. Over what time period does the NERC MOD–25–2 Reliability Standard[49] accurately represent a resource's capability to provide reactive power?

i. For how long is this data valid? Please explain.

ii. If these standards do not accurately represent a resource's reactive power capability, what additional data should resources provide to verify their reactive power capability? Should this data vary by resource type? If so, how and why?

i. Are there maintenance activities needed to maintain reactive power capability that do not also contribute to real power capability?

i. If so, what percentage of a generating facility's operating and maintenance budget is necessary to maintain reactive power capability?

ii. Does this differ by type of generating resource? If so, how?

b. Non-Synchronous Resources

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.

k. As discussed above,[50] the AEP Methodology determines a resource's cost of reactive power capability by applying an allocation factor to four groups of costs that are involved in the production or consumption of reactive power for a synchronous resource: (1) The generator and exciter, (2) the step-up transformer, (3) accessory electric equipment used to support the operation of the generator and exciter, and (4) the remaining production plant investment. For each of these groups of costs, assuming that the non-synchronous resource type can provide reactive power capability, please identify what non-synchronous resource equipment corresponds to the synchronous resource equipment used in the AEP Methodology and how that equipment is related to the production of reactive power. Please explain if that equipment is also related to the production of real power. Please specify if the equipment identified is specific to a type of non-synchronous resource (*e.g.,* wind, solar, battery).

i. In the alternative, please describe what groups of costs are involved in the production or consumption of reactive

[48] *See, e.g., Panda Stonewall LLC,* 174 FERC ¶ 61,266, at PP 99, 107–109 (2021) (finding that a reactive power supplier was entitled to use its nameplate power factor in calculating its reactive power revenue requirement, rather than being limited to the power factor specified in its interconnection agreement, since the facility was a new synchronous generator facility and degradation of its reactive power output was not an issue).

[49] The NERC MOD–25–2 standard refers to verification and data reporting of generator real and reactive power capability as well as synchronous condenser reactive power capability. Under this standard, each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable facilities within 90 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operating data. Reliability Standard MOD–25–2 (Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability), at Requirement R2.

[50] *See supra* Section I.

power for a non-synchronous resource and how a non-synchronous resource's equipment would be allocated to each of those groups. Please explain if these groups are involved in the production or consumption of power other than reactive power.

l. Which, if any, of the four groups under the AEP Methodology do costs associated with the collection system of a non-synchronous resource fall into and why?

i. If they do not fall into any of those groups, should those costs related to the collection system be recovered? Why?

ii. Is the collection system comparable to the isolated phase bus of a synchronous resource? Why or why not? In what ways are they similar and in what ways are they different? What other aspects of a non-synchronous resource does a collection system serve?

m. Please explain whether it is necessary for a Type 3 wind turbine,[51] Type 4 wind turbine,[52] or solar PV facility to produce real power at a particular time in order for the resource to provide reactive power capability at that time.

i. If so, what are the implications, if any, for the current proportionality requirement on reactive power from non-synchronous resources?

n. Should the AEP Methodology be altered to account for the intermittent availability of some non-synchronous resources? Why or why not?

o. Solar resources can be designed with power factors much lower than those of synchronous resources,[53] which implies a much higher reactive power capability and results in higher revenue requirements under current application of the AEP Methodology for solar generating facilities versus a comparable synchronous resource, all else being equal. Should the AEP Methodology be altered to account for this difference? Why or why not?

i. Refer to Section II.A.5, question l.i. Would allocating the costs of solar generating facilities into cost categories different from those categories defined under the AEP Methodology, and using a solar generating facility's power factor, result in a revenue requirement more or less comparable to that of a synchronous generating facility, all else being equal?

c. Evidentiary Support

p. What options are available to collect independently verifiable cost information from MBR sellers that have received waiver of the accounting and FERC Form No. 1 requirements to support their reactive power capability revenue requirements? For example, how should MBR sellers that receive reactive power capability compensation track their equipment costs and support their proposed reactive power revenue requirements?

q. In order to simplify and provide transparency to proposed reactive power capability compensation filings, should the Commission require, in PJM, MISO, and non-RTO/ISO regions that compensate for reactive power capability based on the costs of individual resources or on a fleet-wide basis, reactive power filers to include with their filing a standardized form with recognized schedules and officer and independent accountant certification requirements? Please explain why or why not.

i. Would the standardized form allow for better comparisons between reactive power rates and/or allow the reactive power rates to be more easily refreshed to reflect degradation or other changes to reactive power capability? If not, why not?

ii. Should the form contain similar information as the relevant USofA accounts used in the AEP Methodology? If not, why not? If yes, please specify the types of information that would be necessary to calculate a reactive power revenue requirement.

iii. If the Commission pursued a standardized form approach, what cost support should be included in a standardized form?

d. Potential Overcompensation in PJM

r. Refer to the PJM Market Monitor's concerns regarding the potential in PJM of overpayment for reactive power capability.[54] In PJM and other RTOs/ISOs with centralized capacity markets, how do resources typically account for revenues from reactive power compensation when calculating their capacity offers?

i. If a resource accounts for revenues from reactive power compensation when calculating its capacity offers, does that approach ensure that the resource does not receive double compensation for providing reactive power capability service? Please explain why or why not.

ii. Please explain how the lack of accounting for revenues from reactive power compensation when calculating resources' capacity offers does not constitute double compensation.

s. 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?

i. If so, how should such overcompensation be corrected?

ii. If not, please explain why no double-recovery occurs.

*B. Alternative Methodologies*

29. As noted above, the AEP Methodology is currently used as the Commission's approach to developing revenue requirements for reactive power capability in PJM, MISO, and by transmission providers in non-RTO/ISO regions. The Commission, in this NOI, would like to explore whether other potential alternative methodologies not based on the costs of the particular resource(s) at issue in a given proceeding should be considered or better used to develop reactive power capability revenue requirements.

30. One possible alternative approach is a flat rate methodology, which would be based on the total reactive power payments made by transmission customers in a region divided by the MVARs consumed in the region. This ''dollars per MVAR-year'' value may be determined either for each class of resource (solar, wind turbine, combined-cycle, combustion turbine, and hydroelectric) or a single value could be paid to all classes of resources similar to the approach used in ISO–NE and NYISO. We seek comment on the potential benefits and drawbacks of using any flat rate methodology for reactive power capability compensation.

31. Another possible approach to reactive power capability compensation is replacement cost ratemaking. Under this approach, the lowest-cost technology capable of providing reactive power capability, such as a synchronous condenser, is used to establish a per-MVAR-year rate. Then, all resources would be paid the same amount based upon their tested MVAR capability. Replacement cost ratemaking derives from the Supreme Court's decision in *Smyth* v. *Ames,*[55] in which the Court indicated that appropriate rate base is

[51] Type 3 wind turbines have doubly-fed induction generators with rotor terminals connected to power converters. The stator terminals of Type 3 wind turbines are directly connected to the bulk electric system.

[52] Type 4 wind turbines use either synchronous or asynchronous generators with generator stator terminals connected to a power converter. The power converters of Type 4 wind turbines are directly connected to the bulk electric system.

[53] *See, e.g.,* Delta's Edge Solar, LLC, Exhibit DES–1, Docket No. ER21–1452–000, at 8 (filed Mar. 16, 2021); Crossett Solar Energy, LLC, Exhibit CSE–1, Docket No. ER21–1453–000, at 8 (filed Mar. 16, 2021).

[54] *See supra* Section II.A.4.

[55] 169 U.S. 466 (1898). The U.S. Supreme Court permitted the Commission to use original cost ratemaking in place of replacement or reproduction cost given the difficulty of determining fair value in most cases. *FPC* v. *Hope Nat. Gas Co.,* 320 U.S. 591 (1944).

based on the replacement cost or fair value of the rate base.[56] Such a replacement cost approach could also form a benchmark for evaluating the justness and reasonableness of proposed reactive power capability revenue requirements, where any proposed rates above the cost of the alternative technology would be considered unjust and unreasonable unless the record demonstrates that the resource's costs of investment in reactive power capability supports the proposed revenue requirement.

1. Questions Regarding Alternative Methodologies

32. We encourage comments regarding the topics discussed above in this section. The following questions are designed to explore further potential alternative methodologies. Commenters need not answer every question enumerated below.

a. Should alternative methodologies to the AEP Methodology be considered for the calculation of reactive power capability revenue requirements? If not, why not? If so, what alternative methodologies to the AEP Methodology could be used for calculating reactive power revenue requirements that would accurately capture the cost of providing reactive power capability? Please clarify if any methodology is specific to certain types of resources or not. For example, what methodology could appropriately account for the technical characteristics of non-synchronous resources that do not exist in synchronous resources? How would developing revenue requirements under such a new methodology compare to developing revenue requirements using the AEP Methodology?

b. Should a flat rate approach to reactive power compensation differ depending on the type of resource, or should one rate be used for all resource types?

c. Under a flat rate approach:

i. How should the rate be initially set, and how would it be adjusted over time (*e.g.,* for inflation)?

ii. Should payments to a specific resource be based on the resource's tested reactive power capability or its actual reactive power output?

iii. How often should the resource's reactive power capability be tested?

d. Under a replacement cost approach:

i. What alternative technology should be used to establish the rate and how should that alternative technology be determined?

ii. How often should the alternative technology used to establish the rate be reevaluated?

e. Would a change to a flat rate or replacement rate approach require resources to change any of their accounting, record keeping or any other administrative processes?

i. Would such a change have an impact on capital investment decisions? Are there any other effects that such a change would cause? If possible, please provide numbers to quantify statements.

f. In regions such as CAISO and SPP, where resources are not directly compensated for their reactive power capabilities, how do resources recover the costs of their investment in reactive power capability?

g. Refer to the PJM Market Monitor's proposal to provide for reactive power compensation in PJM through the capacity market rather than through a separate cost-of-service construct.[57] In regions with a centrally-cleared capacity market, would it be preferable for resources to recover the costs of their investment in reactive power capability by embedding those costs in their capacity market offers, rather than using a separate cost-based rate? Please describe any advantages or disadvantages to this approach and any modifications this would require in the applicable region's OATT and market rules.

*C. Distribution-Connected Resources*

33. The Commission has previously found that a transmission provider need not provide compensation to resources for reactive power if the resource is not under the control of the control area operator.[58] Schedule 2 of the *pro forma* OATT similarly requires that generation facilities and non-generation resources capable of providing reactive power be ''under the control of the control area operator.''

34. In several recent cases,[59] the PJM Market Monitor has challenged the eligibility of distribution-connected resources with Commission-jurisdictional interconnection agreements to receive compensation for reactive power capability (within the standard power factor range) under Schedule 2 of PJM's tariff.[60] The PJM Market Monitor has argued in these cases that such resources should not receive reactive power compensation from PJM because the resources have not established that they provide reactive power capability service to the PJM transmission system, as required by Schedule 2.[61] The PJM Market Monitor likens such resources to pseudo-tied resources, which are excluded from eligibility to file for reactive power compensation under Schedule 2 of PJM's tariff. Other protestors have also argued that distribution-connected resources are not under the operational control of the transmission system operator and therefore cannot provide reactive power capability service consistent with the PJM tariff.[62]

35. We are interested in exploring the PJM Market Monitor's concerns further, as well as whether these concerns are relevant for other regions.

1. Questions Regarding Distribution-Connected Resources

36. The Commission encourages comments regarding the topics broadly discussed above. The following questions are designed to identify whether resources in PJM and elsewhere that are interconnected to a distribution system and participate in wholesale markets are technically capable of providing reactive power to the transmission system in such a way that these resources should be eligible for reactive power capability compensation through transmission rates. Commenters need not answer every question enumerated below.

a. For a distribution-connected resource, is reactive power dispatchable by direction of the transmission provider? Please explain, including whether the answer to this question depends on whether the resource has a

[56] *Smyth,* 169 U.S. at 544 (''the rights of the public would be ignored if rates for the transportation of persons or property on a railroad are exacted without reference to the fair value of the property used for the public'').

[57] *See supra* Section II.A.4.

[58] *Otter Tail Power Co.,* 99 FERC ¶ 61,019, at 61,092 (2002).

[59] *See supra* note 36.

[60] Schedule 2 of PJM's tariff is nearly identical to Schedule 2 of the *pro forma* OATT. It provides in relevant part as follows (emphasis added):

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.

[61] *See, e.g.,* Mechanicsville Solar, LLC, Protest of the Independent Market Monitor for PJM, Docket No. ER21–2091–000 (filed June 28, 2021).

[62] *See, e.g.,* Northern Virginia Electric Cooperative, Inc., Old Dominion Electric Cooperative, and Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company; Mechanicsville Solar, LLC, Protest and Comments Monitor for PJM, Docket No. ER21–2091–000 (filed June 25, 2021).

Commission-jurisdictional interconnection agreement with the transmission system owner/operator and whether the resource is synchronous or non-synchronous.

b. If reactive power produced by a distribution-connected resource cannot be dispatched by the transmission system operator to provide voltage support to the transmission system, should a distribution-connected resource be compensated through transmission rates for its reactive power capability? Why or why not?

c. If distribution-connected resources are dispatchable for reactive power by the transmission provider, to what extent are distribution-connected resources able to provide reactive power capability service to the transmission system? Are there physical characteristics (*e.g.,* distribution-connected resource characteristics and location, system topology, etc.) or other indicators that could be analyzed to determine accurately whether a distribution connected resource is able to provide reactive power capability service to the transmission system?

d. Are resources connected to a distribution system subject to reactive power capability testing requirements? If so, what are those requirements?

**III. Comment Procedures**

37. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice, including any related matters or alternative proposals that commenters may wish to discuss. Initial Comments are due January 31, 2022, and Reply Comments are due February 28, 2022. Comments must refer to Docket No. RM22–2–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

38. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's website at *http://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

39. Those unable to file electronically may mail comments via the U.S. Postal Service to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC, 20426. Hand-delivered comments or comments sent via any other carrier should be delivered to: Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

40. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

**IV. Document Availability**

41. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*http://www.ferc.gov*). At this time, the Commission has suspended access to the Commission's Public Reference Room due to the President's March 13, 2020 proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19).

42. From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

43. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202)502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

By direction of the Commission.

Issued: November 18, 2021.

**Kimberly D. Bose,**

*Secretary.*

[FR Doc. 2021–26032 Filed 11–29–21; 8:45 am]

**BILLING CODE 6717–01–P**

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## DEPARTMENT OF ENERGY

### Federal Energy Regulatory Commission

### Combined Notice of Filings #1

Take notice that the Commission received the following electric corporate filings:

*Docket Numbers:* EC22–21–000.
*Applicants:* Evergreen Gen Lead, LLC.
*Description:* Application for Authorization Under Section 203 of the Federal Power Act of Evergreen Gen Lead, LLC.
*Filed Date:* 11/22/21.
*Accession Number:* 20211122–5266.
*Comment Date:* 5 p.m. ET 12/13/21.

Take notice that the Commission received the following Complaints and Compliance filings in EL Dockets:

*Docket Numbers:* EL15–55–004.
*Applicants: Modesto Irrigation District and Turlock Irrigation District* v. *Pacific Gas and Electric Company.*
*Description:* Turlock Irrigation District and Modesto Irrigation District submits Motion for Issuance of an order to show cause, Motion for Additional Remedies and Motion for Expedited Response time and expedited action.
*Filed Date:* 11/22/21.
*Accession Number:* 20211122–5220.
*Comment Date:* 5 p.m. ET 12/13/21.

*Docket Numbers:* EL19–47–000; EL19–63–000; ER21–2444–000; ER21–2877–000.
*Applicants:* Applicant not Found.
*Description:* Motion for Clarification or in the Alternative Motion for Waiver of the Independent Market Monitor for PJM.
*Filed Date:* 11/19/21.
*Accession Number:* 20211119–5045.
*Comment Date:* 5 p.m. ET 12/9/21.

Take notice that the Commission received the following electric rate filings:

*Docket Numbers:* ER19–1553–000.
*Applicants:* Southern California Edison Company.
*Description:* Annual Formula Transmission Rate Update Filing (TO2022) of Southern California Edison Company.
*Filed Date:* 11/19/21.
*Accession Number:* 20211119–5137.
*Comment Date:* 5 p.m. ET 12/10/21.

*Docket Numbers:* ER22–188–000.
*Applicants:* Indra Power Business CT, LLC.
*Description:* Supplement to October 22, 2021 Indra Power Business CT LLC tariff filing.
*Filed Date:* 11/22/21.
*Accession Number:* 20211122–5272.
*Comment Date:* 5 p.m. ET 12/13/21.

*Docket Numbers:* ER22–353–000.
*Applicants:* Indra Power Business MI, LLC.
*Description:* Supplement to November 5, 2021 Indra Power Business MI LLC tariff filing.
*Filed Date:* 11/22/21.
*Accession Number:* 20211122–5271.
*Comment Date:* 5 p.m. ET 12/13/21.

*Docket Numbers:* ER22–416–000.
*Applicants:* Indra Power Business NJ, LLC.
*Description:* Supplement to November 17, 2021 Indra Power Business NJ LLC tariff filing.