Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER10–3297–018.
Applicants: Powerex Corporation.
Description: Notice of Change in Status of Powerex Corp.
Filed Date: 12/21/22.
Accession Number: 20221221–5328.
Comment Date: 5 p.m. ET 1/11/23.

Docket Numbers: ER11–2029–008.
Applicants: Cedar Creek II, LLC.
Description: Triennial Market Power Analysis for Northwest Region of Cedar Creek II, LLC.
Filed Date: 12/22/22.
Accession Number: 20221222–5314.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER11–2557–005; ER11–2552–005; ER11–2558–006; ER11–2555–004; ER11–2556–005.
Applicants: National Grid Port Jefferson, National Grid Glenwood Energy Center LLC, Niagara Mohawk Power Corporation, Massachusetts Electric Company, New England Power Company.
Description: Triennial Market Power Analysis for Northeast Region of New England Power Company, et al.
Filed Date: 12/22/22.
Accession Number: 20221222–5313.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER19–1217–003.
Applicants: Montana-Dakota Utilities Co.
Description: Triennial Market Power Analysis for Northwest Region of Montana-Dakota Utilities Co.
Filed Date: 12/22/22.
Accession Number: 20221222–5320.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER20–2444–005; ER20–2445–005.
Applicants: Prineville Solar Energy LLC, Millican Solar Energy LLC.
Description: Triennial Market Power Analysis for Northwest Region of Millican Solar Energy LLC, et al.
Filed Date: 12/21/22.
Accession Number: 20221221–5333.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER23–724–000.
Applicants: Tri-State Generation and Transmission Association, Inc.
Description: § 205(d) Rate Filing: Initial Filing of Rate Schedule FERC No. 352 to be effective 11/2/2022.
Filed Date: 12/23/22.
Accession Number: 20221223–5001.
Comment Date: 5 p.m. ET 1/13/23.

Docket Numbers: ER23–725–000.
Applicants: PJM Interconnection, L.L.C.
Description: § 205(d) Rate Filing: Critical Natural Gas Infrastructure as Demand Response in the PJM Markets to be effective 2/22/2023.
Filed Date: 12/23/22.
Accession Number: 20221223–5010.
Comment Date: 5 p.m. ET 1/13/23.

Docket Numbers: ER23–726–000.
Applicants: Fresh Air Energy XXIII, LLC.
Description: Baseline eTariff Filing: Fresh Air Energy XXIII, LLC MBR Tariff to be effective 2/6/2023.
Filed Date: 12/23/22.
Accession Number: 20221223–5048.
Comment Date: 5 p.m. ET 1/13/23.

Docket Numbers: ER23–727–000.
Applicants: PGR 2022 Lessee 2, LLC.
Description: Baseline eTariff Filing: PGR 2022 Lessee 2, LLC MBR Tariff to be effective 2/6/2023.
Filed Date: 12/23/22.
Accession Number: 20221223–5051.
Comment Date: 5 p.m. ET 1/13/23.

Docket Numbers: ER23–728–000.
Applicants: PJM Interconnection, L.L.C.
Description: Tariff Amendment: Notice of Cancellation of ISA, SA No. 6590; Queue No. AC1–171 to be effective 10/18/2022.
Filed Date: 12/23/22.
Accession Number: 20221223–5083.
Comment Date: 5 p.m. ET 1/13/23.

The filings are accessible in the Commission's eLibrary system (*https://elibrary.ferc.gov/idmws/search/fercgensearch.asp*) by querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5:00 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: December 23, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

[FR Doc. 2022–28453 Filed 12–29–22; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket Nos. AD22–8–000, AD21–15–000]

Transmission Planning and Cost Management; Joint Federal-State Task Force on Electric Transmission; Notice Inviting Post-Technical Conference Comments

On October 6, 2022, the Federal Energy Regulatory Commission (Commission) convened a technical conference to discuss transmission planning and cost management for transmission facilities developed through local or regional transmission planning processes.

All interested persons are invited to file post-technical conference comments on issues raised during the conference that they believe would benefit from further discussion. In particular, parties are invited to provide comments on the questions listed below.[1] Commenters need not respond to all topics or questions asked, and they are not limited to the topics or questions posed.

Commenters may reference material previously filed in this docket, including the technical conference transcript, but are encouraged to avoid repetition or replication of previous material. In addition, commenters are encouraged, when possible, to provide examples and quantitative data in support of their answers. Comments must be submitted on or before 90 days from the date of this notice.

Comments may be filed electronically via the internet.[2] Instructions are available on the Commission's website *http://www.ferc.gov/docs-filing/efiling.asp.* For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll free at 1–866–208–3676, or for TTY, (202) 502–8659. Although the Commission strongly encourages electronic filing, documents may also be paper-filed. To paper-file, submissions sent via the U.S. Postal Service must be addressed to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE, Washington, DC 20426. Submissions sent via any other carrier must be addressed to: Federal Energy Regulatory Commission, Office of the Secretary, 12225 Wilkins Avenue, Rockville, MD 20852.

For more information about this Notice, please contact: John Riehl (Technical Information), Office of

[1] *Supplemental Notice of Technical Conference,* Docket No. AD22–8–000 (Oct. 4, 2022).

[2] *See* 18 CFR 385.2001(a)(1)(iii) (2021).

Energy Market Regulation, (202) 502–6026, *John.Riehl@ferc.gov.*

Dated: December 23, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

Post-Technical Conference Questions for Comment

Local Transmission Planning Under Order No. 890 and Planning for Asset Management [3] Projects

1. In Order No. 890, the Commission established nine transmission planning principles, including the coordination, openness, transparency, and information exchange principles.[4] The Commission adopted the transmission planning principles in Order No. 890 to remedy opportunities for undue discrimination in expansion of the transmission system on both a local and regional level.[5]

a. Do the existing Order No. 890 transmission planning requirements provide state regulators and other stakeholders with sufficient transparency into and information about public utility transmission providers' local transmission planning criteria and the resulting identification of transmission system needs? If not, please explain how the Commission could revise the coordination, openness, transparency, and information exchange principles in Order No. 890 to provide for enhanced transparency and information sharing. Further, please explain what, if any, additional transparency measures would assist state regulators and other stakeholders in understanding how public utility transmission providers develop their local transmission planning criteria, how those criteria drive local transmission needs, and how public utility transmission providers consider local transmission projects to address those needs.

b. Is there any information beyond that required under the Order No. 890 transmission planning principles that the Commission should consider requiring public utility transmission providers to provide in their local transmission planning processes? For example, should the Commission require that public utility transmission providers make available to state regulators and other stakeholders cost estimates used during transmission planning for all transmission facility alternatives considered to address the transmission needs, including, but not limited to, those transmission facilities that are chosen to address the local transmission planning criteria, or for a subset of those facility alternatives? What would be the advantages and disadvantages of such a requirement? If so, how should cost estimates used during transmission planning for these transmission facilities be calculated?

c. Are there barriers to state regulators and other stakeholders accessing the information that public utility transmission providers provide through their local transmission planning processes (*e.g.,* fees, background checks, etc.)? Do state regulators and other stakeholders have access to the expertise necessary to analyze the information presented and to evaluate the public utility transmission providers' local transmission planning decisions? What actions could the Commission take to reduce any such barriers?

2. Order No. 890's requirements apply to transmission facilities that expand the transmission system, but do not apply to asset management projects, as defined above. However, some public utility transmission providers have processes that provide stakeholders with some transparency into their asset management decisions. For example, Pacific Gas & Electric's Stakeholder Transmission Asset Review (STAR) Process and Southern California Edison's Stakeholder Review Process (SRP) provide stakeholders with the opportunity to engage in a review of PG&E's and Southern California Edison's five-year plan for capital transmission projects so that stakeholders can understand the need for and anticipated costs of projects that are not reviewed in the California Independent System Operator Corp.'s (CAISO) transmission planning process.[6]

a. Should the Commission require public utility transmission providers to provide transparency concerning their asset management decisions? Are there any aspects of Pacific Gas & Electric's STAR Process or Southern California Edison's SRP that would be beneficial to consider? What other considerations are relevant to the transparency of asset management project decisions?

b. Are there barriers to state regulators and other stakeholders analyzing any additional information that the Commission could require public utility transmission providers to provide concerning their asset management projects? For example, do state regulators and other stakeholders have access to the expertise necessary to analyze the information presented? What actions could the Commission take to reduce any such barriers?

3. Could additional transparency facilitated by project-specific disclosure requirements or standardized filing requirements help increase the cost effectiveness of local transmission planning and asset management decisions? Examples include additional transparency and access to local planning criteria, utilities' rankings of their project priorities (subject to CEII protections), requirements for utilities to provide either publicly or to the Commission a standardized disclosure describing the need for a local transmission project or asset management project and why it is a cost-effective solution to that need before money is spent on the planned transmission project (other than any planning costs incurred), and a requirement for utilities to provide advance notice of a project nearing its end of life, among others. To the extent that such requirements may be appropriate, what specific requirements should the Commission impose? For example, for a standardized disclosure described above, should the Commission require utilities to provide such information to stakeholders as part of their local transmission planning process under Order No. 890, or should the Commission require utilities to make a filing with the Commission? At what point in the transmission planning process should these filings be made? Should any such filings be informational, or should they require Commission action? In designing any such requirements, how should the

[3] Asset Management refers to projects and activities that ''encompass the maintenance, repair, and replacement work done on existing transmission facilities as necessary to maintain a safe, reliable, and compliant grid based on existing topology.'' *See So. Cal. Edison Co,* 164 FERC ¶ 61,160 at n.55 (2018); *Cal. Pub. Util. Comm'n* v. *Pac. Gas & Elec. Co.,* 164 FERC ¶ 61,161 at n.119 (2018). Additionally, asset management projects or activities may result in an incidental increase in transmission capacity that is not reasonably severable from the asset management project or activity, and such incidental increase in transmission capacity would not render the asset management project or activity in question a transmission expansion that is subject to the transmission planning requirements of Order No. 890. *See So. Cal. Edison Co,* 164 FERC ¶ 61,160 at P 33 (2018); *Cal. Pub. Util. Comm'n* v. *Pac. Gas & Elec. Co.,* 164 FERC ¶ 61,161 at P 68 (2018).

[4] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 118 FERC ¶ 61,119, at P 444, *order on reh'g,* Order No. 890–A, 121 FERC ¶ 61,297 (2007), *order on reh'g,* Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 126 FERC ¶ 61,228, *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[5] *Id.* PP 57–58, 421–422, 425.

[6] *See, e.g.,* PG&E, TO Tariff, PG&E Electric Tariff Volume No. 5 (0.0.0), Appendix IX, STAR Process (0.0.0). *See also So. Cal. Ed.,* Docket No. ER19–1553–005, at 2 (Dec. 8, 2020) (delegated letter order).

Commission weigh the administrative burden of those requirements against the transparency provided?

Project Implementation and Variance Analysis

4. In Order No. 1000, the Commission required public utility transmission providers to describe the circumstances and procedures by which they will reevaluate the regional transmission plan to determine if delays in the development of a regional or interregional transmission facility requires evaluation of alternative transmission solutions (reevaluation requirement).[7] To comply with this requirement, some public utility transmission providers voluntarily adopted a variance analysis process tied to changes in cost estimates to examine whether a regional transmission facility selected in a regional transmission plan for the purposes of cost allocation remains the more efficient or cost-effective transmission facility if its costs rise above estimates or if there are delays in that regional transmission facility's development.

a. Given that some RTOs/ISOs have voluntarily implemented variance analyses for regional and interregional transmission planning, are there certain best practices in regional and interregional transmission planning variance analyses that should be more widely adopted? Conversely, are there specific elements or characteristics of variance analyses used by certain public utility transmission providers that could be improved? Please describe.

b. What consequences should result if variance analyses show that a regional or interregional transmission facility's costs have increased above an established threshold since it was initially selected in a regional transmission plan for the purposes of cost allocation? What consequences should result if variance analyses show that a regional or interregional transmission facility's estimated benefits have eroded beyond an established threshold since it was initially selected in a regional transmission plan for the purposes of cost allocation?

c. Should the Commission require public utility transmission providers to perform variance analyses as part of their regional transmission planning processes? To what types of regional transmission projects should such a requirement apply?

[7] *Transmission Planning & Cost Allocation by Transmission Owning and Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051, at P 329 (2011).

d. Could variance analysis or similar mechanism be applied to facilitate cost management outside the context of regional or interregional transmission facilities subject to cost allocation under Order No. 1000 and, if so, should the Commission require it? What legal rationale would justify the requirement to use variance analysis? What level of increased costs or decreased benefits would merit evaluation through a variance analysis to determine whether a transmission project continues to be cost-effective? Would it be appropriate to apply a cost or benefits threshold below which or above which, respectively, such a requirement would not apply? Are there any categories of transmission projects for which this cost management method is not appropriate?

e. Who should be responsible for developing the cost estimates used in the variance analysis? The RTO/ISO, the public utility transmission provider, an Independent Transmission Monitor, or another entity? Should this role vary between non-RTO/ISO and RTO/ISO regions, and/or are there general guidelines with regard to independence that should be met for any entity developing cost estimates or bandwidths?

f. Can or should such an approach be designed in order to maximize benefits to consumers, as opposed to focusing only on reducing costs? For example, a given project modification might increase up-front costs of the project, but lower costs for customers in the long-run by enhancing project efficiency and thereby increasing anticipated economic benefits. Should any variance analysis mechanism required by the Commission be designed in a manner that encourages such investments, or at minimum does not inadvertently discourage them? If so, how?

Independent Transmission Monitor (ITM)

5. During the technical conference, many panelists argued in favor of an ITM to review and evaluate a wide range of elements of the transmission planning process, including the transmission planning criteria used to identify transmission facilities. However, others expressed concern that an ITM would be unnecessary or duplicative in light of other regulatory agencies or stakeholders. Given the divergence of views on the potential roles and responsibilities of an ITM, please respond to the following:

a. Please provide a concise but detailed job description for an ITM in both RTOs/ISOs and non-RTOs/ISOs. For example, should the ITM serve as a technical expert that publishes after-the-fact reports assessing public utility transmission providers' transmission plans? Should an ITM assist state regulators and other stakeholder with evaluating potential transmission facilities and their costs? Should an ITM participate in proceedings before the Commission? Should an ITM develop and monitor benchmark estimates of costs using data collected over time? Should an ITM assess continuing need for certain transmission projects? Should an ITM attend local and regional transmission planning meetings? Please list specific roles that would be appropriate for an ITM, and please explain at which stage of the transmission planning process those roles should be leveraged (*i.e.,* inputs and assumptions, planning study results, selection, cost allocation, project development).

b. What are the potential benefits of an ITM? Please describe with specificity, and address whether these benefits are particular to RTO/ISO or non-RTO/ISO regions, or present in both.

c. Are there specific challenges, including how the roles and responsibilities of the ITM relate to Commission jurisdiction, regarding the creation of an ITM, or the responsibilities that an ITM might have that the Commission should consider? If so, please describe.

d. What information would the ITM need access to in carrying out these responsibilities? Should the ITM have access to transmission planning and cost information, including CEII information? Please describe with specificity the information that the ITM should be able to review.

e. If an ITM were established, should the Commission periodically review the need for, role, and/or scope of that entity?

f. Would the ITM's functions potentially overlap with the functions of a public utility transmission provider, particularly in an RTO/ISO? If so, where would the overlap occur? Where should the ITM be housed, and what are the pros and cons of that arrangement (*e.g.,* internal or external independent entity similar to or incorporated within IMMs, an office within the Commission itself, or some other arrangement)? How should an ITM be funded?

g. How, if at all, should an ITM's role differ between RTO/ISO regions and non-RTO/ISO regions? What legal authority (or authorities) could the Commission rely on in establishing an ITM, and does that authority differ with respect to RTO/ISO and non-RTO/ISO regions? Should the Commission require an ITM in both RTOs/ISOs and non-

RTOs/ISOs? If so, please state the legal justification in both RTOs/ISOs and non-RTOs/ISOs. What implications does the Commission's scope of authority have with regard to the potential structure and duties of the ITM?

h. How often and at what stages of the local and regional transmission planning processes and interregional transmission coordination process should an ITM review and evaluate transmission facility cost information, if at all (*e.g.,* during the transmission planning cycle, during the development of the transmission facility, or following the completion of construction of the transmission facility)? What types of costs should an ITM review and evaluate (*e.g.,* capital costs, labor costs, etc.), if any? What should an ITM do with the information that is reviewed and evaluated?

i. Should the Commission establish a minimum threshold (*e.g.,* costs, voltage, etc.) for transmission facilities that would be reviewed by an ITM? If so, what should that threshold be and why? In RTO/ISO regions, should an ITM review only transmission facilities that address local transmission planning criteria and asset management transmission projects?

j. Should an ITM be subject to standards of conduct or other professional criteria? If so, what should those standards be?

Commission's Formula Rates and Prudence Practices

6. Under the MISO Protocol Orders,[8] the Commission required public utility transmission providers to include safeguards in their transmission formula rate protocols to provide transparency in the public utility transmission providers' implementation of their transmission formula rates, to ensure that input data is correct, and that their calculations are performed consistent with the formula.

a. What, if any, specific standard formula rate protocols that the Commission requires under the MISO Protocol Orders and other precedent should be revised, and how? For example, should the Commission require public utility transmission providers to provide additional time for state regulators and other stakeholders to review and respond to annual updates before they are submitted to the Commission?

7. Under the Commission's current prudence standard, the Commission presumes that a public utility transmission provider's expenditures are prudent in the absence of a challenge casting serious doubt on such prudence, and establishing serious doubt regarding prudence requires ''reliable, probative, and substantial evidence.'' [9]

a. Should the Commission alter the rebuttable presumption of prudence of expenditures in certain circumstances, such as with respect to specific types of expenditures (*e.g.,* asset management expenditures), where alternatives to transmission have not been considered, or where a state regulator has not reviewed a project for need and cost? If so, how should the standard be altered and in which circumstances?

8. Other than transparency criteria, are there ways that the Commission could consider local planning criteria that utilities use in determining how the prudence standard is applied to specific expenditures? For example, with respect to local transmission and/or asset management projects, should the Commission establish certain guidance for planning such projects and only apply the rebuttable presumption of prudence to projects that follow the Commission-determined guidelines for planning such projects? What are the pros and cons of that approach?

Federal and State Regulation of Transmission Facilities

9. Some panelists at the technical conference argued that there is a regulatory gap with regard to ensuring that a cost-effective mix of local, asset management, and regional reliability transmission projects is developed. Generally speaking, for such projects they contend that state siting processes, the formula rate process, and the Commission's prudence standard and existing transparency requirements, may not provide adequate assurance that utilities will choose a cost-effective mix of projects. Do you agree that there is a regulatory gap for local projects and/or asset management projects, and if so, why or why not? Does the presence or extent of a regulatory gap depend on the underlying state regulatory framework? If so, how? If you agree that one or more regulatory gaps exist, how should the Commission address these gaps? For example, should the Commission modify the prudence standard and/or formula rate protocols for transmission or asset management projects falling within such a regulatory gap? Should the Commission establish new transmission planning requirements to help ensure that such projects are cost-effective? In your response, please discuss whether the Commission's approach should depend on the underlying state regulatory framework. Also please discuss the extent to which your recommended reforms, standing alone, will address the perceived gaps, or whether they should or must be coupled with other solutions.

10. Some panelists argued that certain types of projects do not receive adequate state, regional, or federal scrutiny with regard to project prudence/need. For example, the Commission has held that asset management and end-of-life decisions are not subject to Order No. 890 planning requirements, and panelists highlighted that in some states such projects do not require a certificate of public convenience and necessity. Do you agree that some projects are not subject to adequate review, and if so, why or why not? What particular types of projects do not receive adequate scrutiny (if any), and should there be some form of heightened scrutiny for them? If so, what kind of heightened scrutiny would be appropriate, and how would that scrutiny be applied?

11. The Commission has authority over the justness and reasonableness of the rates for wholesale transmission service, including recovery of the costs of transmission facilities used in providing transmission service and the prudence of those expenditures, and has approved public utility transmission provider proposals to recover their costs of providing transmission service through formula rates. Under a formula rate, the Commission reviews and accepts as the rate a formula for calculating the utility's cost of service, including clear definitions of inputs to that formula and a process for updating rates every year as the utility's costs change. State regulators typically have authority to evaluate whether certain transmission facilities to be built within their state may be constructed (*i.e.,* whether to grant the proposed facility a Certificate of Public Convenience and Necessity (CPCN)), which may involve evaluation of the need for, and projected costs of, a proposed transmission facility.

a. Are there differences among the states' CPCN authorities and processes, and what is the extent of those differences?

b. Should the Commission consider relying on a state regulator's determination in a CPCN proceeding

[8] *Midwest Indep. Transmission Sys. Operator, Inc.,* 139 FERC ¶ 61,127 at P 9 (2013); *see also Midwest Indep. Transmission Sys. Operator, Inc.,* 143 FERC ¶ 61,149 (2013); *Midcontinent Indep. Sys. Operator, Inc.,* 146 FERC ¶ 61,212 (2014); and *Midcontinent Indep. Sys. Operator, Inc.,* 150 FERC ¶ 61,025 (2015) (collectively, MISO Protocol Orders).

[9] *Delmarva Power & Light Co.,* 172 FERC ¶ 61,175, at P 15 (2020) (citing *New Eng. Power Co.,* Opinion No. 231, 31 FERC ¶ 61,047 (1985)).

that a proposed transmission facility is in the public convenience and necessity when considering whether the costs of that transmission facility may be recovered through a formula rate? Should the Commission prohibit the recovery of transmission project costs through a formula rate if those projects have not been subject to a robust state CPCN process? Why or why not? Should the Commission accept as self-proving an attestation from state regulators that such a robust CPCN process is used in their state? If yes, are there specific factors or features of a state regulator's CPCN process that indicate whether a potential transmission facility has been robustly evaluated for need and cost? If not, are there other indicators (*e.g.,* other regulatory determinations, third-party analyses, legislative reports, etc.) that demonstrate that the need for and costs of a potential transmission facility have been robustly reviewed? What are the advantages and disadvantages of this approach?

c. If formula rate treatment is not permitted, how should costs related to the new transmission project or transmission facility be separated out for recovery in a stated rate proceeding (*e.g.,* should all costs related to the transmission facility be excluded from formula rate recovery, or only capital costs)? How could the timing of the state regulatory proceeding impact a public utility transmission provider's ability to file for cost recovery of proposed transmission facilities subject to CPCN review? How, if at all, would the inability to recover the costs of certain transmission facilities through a public utility transmission provider's formula rate impact its annual formula rate proceedings?

d. If the Commission determines that a potential transmission facility has not been robustly evaluated at the state level for need and cost, are there other regulatory requirements that the Commission could impose short of requiring a transmission facility's costs to be recovered through stated rates rather than formula rates? If so, what options are available and what are the pros and cons of those options?

Other Questions

12. Some panelists argued that the timing of cost management or oversight mechanisms is relevant to ensuring cost effectiveness, contending that cost scrutiny must be applied to decisions during the local or regional transmission planning phase in order to influence those decisions. Do you agree, and if so why or why not? What are the possibilities for facilitating timely cost management before money is spent on transmission projects (aside from planning costs)?

[FR Doc. 2022–28454 Filed 12–29–22; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL OP–OFA–050]

Environmental Impact Statements; Notice of Availability

Responsible Agency: Office of Federal Activities, General Information 202–564–5632 or *https://www.epa.gov/nepa.*

Weekly receipt of Environmental Impact Statements (EIS) Filed December 19, 2022 10 a.m. EST Through December 23, 2022 10 a.m. EST Pursuant to 40 CFR 1506.9.

Notice

Section 309(a) of the Clean Air Act requires that EPA make public its comments on EISs issued by other Federal agencies. EPA's comment letters on EISs are available at: *https://cdxapps.epa.gov/cdx-enepa-II/public/action/eis/search.*

EIS No. 20220193, Final, FEMA, NJ, ADOPTION—Rebuild by Design—Hudson River (RBD–HR), Review Period Ends: 01/30/2023, Contact: John McKee 202–704–7160.

The Federal Emergency Management Agency (FEMA) has adopted the Department of Housing and Urban Development's Final EIS No. 20170101, filed 6/8/2017 with the Environmental Protection Agency. The FEMA was not a cooperating agency on this project. Therefore, republication of the document is necessary under Section 1506.3(c) of the CEQ regulations.

Amended Notice

EIS No. 20220175, Draft, BIA, DOI, OR, Coquille Indian Tribe Fee to Trust Gaming Facility Project, Comment Period Ends: 02/23/2023, Contact: Tobiah Mogavero 435–210–0509.

Revision to FR Notice Published 11/25/2022; Extending the Comment Period from 01/09/2023 to 02/23/2023.

Dated: December 23, 2022.

Cindy S. Barger,

Director, NEPA Compliance Division, Office of Federal Activities.

[FR Doc. 2022–28438 Filed 12–29–22; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Agency for Healthcare Research and Quality

Patient Safety Organizations: Voluntary Relinquishment for the Zephcare PSO

AGENCY: Agency for Healthcare Research and Quality (AHRQ), Department of Health and Human Services (HHS).

ACTION: Notice of delisting.

SUMMARY: The Patient Safety and Quality Improvement Final Rule (Patient Safety Rule) authorizes AHRQ, on behalf of the Secretary of HHS, to list as a patient safety organization (PSO) an entity that attests that it meets the statutory and regulatory requirements for listing. A PSO can be ''delisted'' by the Secretary if it is found to no longer meet the requirements of the Patient Safety and Quality Improvement Act of 2005 (Patient Safety Act) and Patient Safety Rule, when a PSO chooses to voluntarily relinquish its status as a PSO for any reason, or when a PSO's listing expires. AHRQ accepted a notification of proposed voluntary relinquishment from the Zephcare PSO, PSO number P0200, of its status as a PSO, and has delisted the PSO accordingly.

DATES: The delisting was effective at 12:00 Midnight ET (2400) on December 8, 2022.

ADDRESSES: The directories for both listed and delisted PSOs are ongoing and reviewed weekly by AHRQ. Both directories can be accessed electronically at the following HHS website: *https://www.pso.ahrq.gov/listed.*

FOR FURTHER INFORMATION CONTACT: Cathryn Bach, Center for Quality Improvement and Patient Safety, AHRQ, 5600 Fishers Lane, MS 06N100B, Rockville, MD 20857; Telephone (toll free): (866) 403–3697; Telephone (local): (301) 427–1111; TTY (toll free): (866) 438–7231; TTY (local): (301) 427–1130; Email: *pso@ahrq.hhs.gov.*

SUPPLEMENTARY INFORMATION:

Background

The Patient Safety Act, 42 U.S.C. 299b–21 to 299b–26, and the related Patient Safety Rule, 42 CFR part 3, published in the **Federal Register** on November 21, 2008 (73 FR 70732–70814), establish a framework by which individuals and entities that meet the definition of provider in the Patient Safety Rule may voluntarily report information to PSOs listed by AHRQ, on