the requirements of Rules of Practice and Procedure, 18 CFR 385.210 and 385.214. Any motions to intervene must be received on or before the specified deadline date for the particular proceeding.

*Filing and Service of Responsive Documents:* All filings must (1) bear in all capital letters the ''COMMENTS CONTESTING QUALIFICATION FOR A CONDUIT HYDROPOWER FACILITY'' or ''MOTION TO INTERVENE,'' as applicable; (2) state in the heading the name of the applicant and the project number of the application to which the filing responds; (3) state the name, address, and telephone number of the person filing; and (4) otherwise comply with the requirements of sections 385.2001 through 385.2005 of the Commission's regulations.[1] All comments contesting Commission staff's preliminary determination that the facility meets the qualifying criteria must set forth their evidentiary basis.

The Commission strongly encourages electronic filing. Please file motions to intervene and comments using the Commission's eFiling system at *http://www.ferc.gov/docs-filing/efiling.asp.* Commenters can submit brief comments up to 6,000 characters, without prior registration, using the eComment system at *http://www.ferc.gov/docs-filing/ecomment.asp.* You must include your name and contact information at the end of your comments. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov,* (866) 208–3676 (toll free), or (202) 502–8659 (TTY). In lieu of electronic filing, you may send a paper copy. Submissions sent via the U.S. Postal Service must be addressed to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street NE, Room 1A, Washington, DC 20426. Submissions sent via any other carrier must be addressed to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852. A copy of all other filings in reference to this application must be accompanied by proof of service on all persons listed in the service list prepared by the Commission in this proceeding, in accordance with 18 CFR 385.2010.

*Locations of Notice of Intent:* 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 website at *http://www.ferc.gov/docs-filing/elibrary.asp.* Enter the docket number (*i.e.,* CD23–3) in the docket number field to access the document. You may also register online at *http://www.ferc.gov/docs-filing/esubscription.asp* to be notified via email of new filings and issuances related to this or other pending projects. Copies of the notice of intent can be obtained directly from the applicant. For assistance, call toll-free 1–866–208–3676 or email *FERCOnlineSupport@ferc.gov.* For TTY, call (202) 502–8659.

Dated: November 30, 2022.

**Kimberly D. Bose,**

*Secretary.*

[FR Doc. 2022–26473 Filed 12–5–22; 8:45 am]

BILLING CODE 6717–01–P

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## DEPARTMENT OF ENERGY

### Federal Energy Regulatory Commission

**[Docket No. ER23–493–000]**

### Thunder Wolf Energy Center, LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of Thunder Wolf Energy Center, LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is December 20, 2022.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically may mail similar pleadings to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426. Hand delivered submissions in docketed proceedings should be delivered to Health and Human Services, 12225 Wilkins Avenue, Rockville, Maryland 20852.

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*) using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. At this time, the Commission has suspended access to the Commission's Public Reference Room, due to the proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19), issued by the President on March 13, 2020. For assistance, contact the Federal Energy Regulatory Commission at *FERCOnlineSupport@ferc.gov* or call toll-free, (886) 208–3676 or TYY, (202) 502–8659.

Dated: November 30, 2022.

**Kimberly D. Bose,**

*Secretary.*

[FR Doc. 2022–26475 Filed 12–5–22; 8:45 am]

BILLING CODE 6717–01–P

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## DEPARTMENT OF ENERGY

### Federal Energy Regulatory Commission

**[Docket No. AD23–3–000]**

### Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements; Supplemental Notice of Staff-Led Workshop

As announced in the Notice of Staff-Led Workshop issued in this proceeding on October 6, 2022, Federal Energy Regulatory Commission (Commission) staff will convene a workshop to discuss whether and how the Commission could establish a minimum requirement for Interregional Transfer Capability for public utility transmission providers in transmission planning and cost allocation processes on December 5 and 6, 2022, from approximately 12:00 p.m. to 5:00 p.m. Eastern Time.

The purpose of this workshop is to consider the question of whether and how to establish a minimum requirement for Interregional Transfer

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[1] 18 CFR 385.2001–2005 (2021).

Capability. Topics for discussion may include: how to determine the need for and benefit of setting a minimum requirement for Interregional Transfer Capability; what to consider in establishing a potential Interregional Transfer Capability requirement, including who would be responsible for determining a minimum Interregional Transfer Capability requirement and what would be the objective and drivers of such a requirement; what process could be used in establishing a minimum Interregional Transfer Capability requirement to determine key data inputs, modeling techniques, and relevant metrics; and how costs for transmission facilities intended to increase Interregional Transfer Capability should be allocated and how to ensure a minimum amount of Interregional Transfer Capability is achieved and maintained.

While the workshop is not for the purpose of discussing any specific matters before the Commission, some workshop discussions may involve issues raised in proceedings that are currently pending before the Commission. These proceedings include, but are not limited to:

| | Docket Nos. |
|---|---|
| Invenergy Transmission LLC | AD22–13–000. |
| Invenergy Transmission LLC v. Midcontinent Independent System Operator, Inc | EL22–83–000. |
| SOO Green HVDC Link ProjectCo, LLC v. PJM Interconnection, LLC | EL21–85–000, EL21–103–000. |
| PPL Electric Utilities Corporation, PJM Interconnection, L.L.C | ER22–2690–000, ER22–2690–001. |
| Appalachian Power Company, PJM Interconnection, L.L.C | ER19–2105–005. |
| Neptune Regional Transmission System, LLC and Long Island Power Authority v. PJM Interconnection, L.L.C. | EL21–39–000. |
| WestConnect Public Utilities | ER22–1105–000. |
| PPL Electric Utilities Corporation | ER22–1606–000. |
| Southwest Power Pool, Inc | ER22–1846–000. |

Attached to this Supplemental Notice is an agenda for the workshop, which includes the workshop program and expected panelists.

Panelists are asked to submit advance materials to provide any information related to their respective panel (*e.g.,* summary statements, reports, whitepapers, studies, or testimonies) that panelists believe should be included in the record of this proceeding by November 21, 2022. Panelists should file all advance materials in the AD23–3–000 docket.

The workshop will take place virtually, with remote participation from both presenters and attendees. The workshop will be open to the public and there is no fee for attendance. Information will also be posted on the Calendar of Events on the Commission's website, *www.ferc.gov,* prior to the event.

The workshop will be transcribed and webcast. Transcripts will be available for a fee from Ace Reporting (202–347–3700). A free webcast of this event is available through the Commission's website. Anyone with internet access who desires to view this event can do so by navigating to *www.ferc.gov's* Calendar of Events and locating this event in the Calendar. The Federal Energy Regulatory Commission provides technical support for the free webcasts. Please call (202) 502–8680 or email *customer@ferc.gov* if you have any questions.

Commission workshops are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations, please send an email to *accessibility@ferc.gov,* call toll-free (866) 208–3372 (voice) or (202) 208–8659 (TTY), or send a fax to (202) 208–2106 with the required accommodations.

For more information about this workshop, please contact Jessica Cockrell at *jessica.cockrell@ferc.gov* or (202) 502–8190. For information related to logistics, please contact Sarah McKinley at *sarah.mckinley@ferc.gov* or (202) 502–8368.

Dated: November 30, 2022.

**Kimberly D. Bose,**

*Secretary.*

**Staff-Led Workshop Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements, Docket No. AD23–3–000, December 5–6, 2022**

*Agenda and Speakers*

Background

To aid in our discussion at the workshop, we will use the following terms:

• For this discussion, the definition of Interregional Transfer Capability is consistent with total transfer capability as defined in the Commission's regulations: ''the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Commission-approved Reliability Standards.'' 18 CFR 37.6(b)(1)(vi) (2021). In the context of Interregional Transfer Capability, an ''area'' in the above definition would be a transmission planning region composed of public utility transmission providers.

• For this discussion, Transfer Transmission Facility is defined as a transmission facility that increases the amount of electric power that can be moved or transferred reliably from one transmission planning region to another by way of all transmission lines (or paths) between those transmission planning regions. For purposes of geographic location, a Transfer Transmission Facility may be located entirely within a single transmission planning region (*i.e.,* either a local transmission facility or a regional transmission facility), or it may span two or more transmission planning regions (*i.e.,* an interregional transmission facility).

Day One: Monday, December 5, 2022

12:00 p.m.–12:10 p.m.: Welcome and Opening Remarks

12:10 p.m.–12:25 p.m.: Presentation from Dr. Dev Millstein, Research Scientist, Lawrence Berkeley National Lab, *Empirical Estimates of Transmission Value using Locational Marginal Prices*

12:25 p.m.–2:25 p.m.: Panel 1: Determining the Need for Additional Interregional Transfer Capability

This panel will explore whether the existing transmission planning and cost allocation and the interregional coordination and cost allocation processes adequately consider the need to establish a minimum requirement for Interregional Transfer Capability between neighboring transmission planning regions. In addition, the panel will discuss the specific drivers that may necessitate the establishment of a minimum requirement.

This panel may include a discussion of the following topics:

1. What are the current levels of Interregional Transfer Capability between transmission planning regions? Is more Interregional Transfer Capability between transmission planning regions needed? Why or why not?

2. Is the potential need for additional Interregional Transfer Capability currently considered in any transmission planning processes and if so, how? To the extent such needs are considered, have they resulted in the development of any transmission facilities?

3. What are the drivers of the need for increasing Interregional Transfer Capability? To what extent do these vary based on regional and system characteristics (*e.g.,* weather patterns, load diversity, resource mix, etc.)? Are there barriers to identifying or assessing these drivers?

4. Is a minimum amount of Interregional Transfer Capability between transmission planning regions necessary to ensure just and reasonable Commission-jurisdictional rates? If so, what evidence is there to support, or negate, that position? How will planning for a minimum amount of Interregional Transfer Capability produce just and reasonable rates?

5. Does the potential need for a minimum amount of Interregional Transfer Capability differ between RTO and non-RTO regions? Why or why not? Is a minimum amount of Interregional Transfer Capability necessary for non-RTO regions?

Panelists

- *Neil Millar*, Vice President, Infrastructure and Operations Planning, California Independent System Operator Corporation
- *Liza Reed, Ph.D.*, Research Manager, Electricity Transmission, Niskanen Center
- *Michele Kito*, Supervisor, Electric Market Design Section, California Public Utilities Commission
- *Philip D. Moeller*, Executive Vice President, Edison Electric Institute
- *Tricia Pridemore*, Chairman, Georgia Public Service Commission
- *Simon Mahan*, Executive Director, Southern Renewable Energy Association

2:25 p.m.–2:45 p.m.: Break

2:45 p.m.–3:00 p.m.: Presentation from Dr. Adria Brooks, U.S. Department of Energy Grid Deployment Office, Transmission Division

3:00 p.m.–4:55 p.m.: Panel 2: Considerations for Establishing Potential Interregional Transfer Capability Requirements

This panel will discuss who would be responsible for determining a minimum Interregional Transfer Capability requirement and the relevant considerations for establishing such a requirement, assuming that there is such a need. Specifically, this panel will focus on identifying the objective, and drivers, of a minimum Interregional Transfer Capability requirement. This panel may include a discussion of the following topics:

1. What principles should be used to establish a minimum amount of Interregional Transfer Capability (*e.g.,* should a minimum Interregional Transfer Capability requirement be determined based on the cost impact to transmission customers during extreme events, such as extreme weather, wide-spread loss of fuel supply, etc.)?

2. To what extent, if any, should the following be considered when establishing a minimum Interregional Transfer Capability requirement?

a. Historical or projected extreme events (*e.g.,* extreme weather, loss of fuel supply, etc.)

b. Load and resource diversity across a wide geographic area

c. Anticipated changes in the resource mix and demand

d. Improved reliability

e. Avoided production costs

f. Geographic zones with the potential for large amounts of new generation

g. The option value of Transfer Transmission Facilities, as determined by the increased access to supplemental capacity during emergency operating conditions.

h. Increased operator flexibility

i. Others?

3. Should planning criteria other than reliability and resilience be considered in establishing a minimum Interregional Transfer Capability requirement?

4. For this question, please consider: (a) public utility transmission providers in each pair of neighboring transmission planning regions, (b) the public utility transmission providers in all of a transmission planning region's neighboring transmission planning regions, and (c) all public utility transmission providers within an Interconnection.

a. What role should the Commission, relevant groupings of public utility transmission providers described in (a), (b), and (c) above, or other relevant entities play in determining what, if any, minimum amount of Interregional Transfer Capability is needed? What are the advantages and disadvantages of each approach?

b. Should the Commission establish a specific formula or planning process, or instead more general criteria, guidelines, or principles for public utility transmission providers to follow in establishing a minimum Interregional Transfer Capability? Should the Commission allow public utility transmission providers flexibility in whether to work on a bilateral basis with neighboring regions, or require planning to be carried out across a broader geography? What are the advantages and disadvantages of each approach?

c. Should the principles considered be consistent for (a), (b) or (c) above? What are the advantages and disadvantages of each approach?

5. How should merchant transmission facility developers and public utility transmission providers conducting transmission planning avoid planning duplicative or conflicting transmission facilities to increase Interregional Transfer Capability?

6. To what extent, if at all, would a minimum Interregional Transfer Capability requirement complement or conflict with a potential new or modified NERC Reliability Standard that requires consideration of extreme heat and cold events as proposed in Docket No. RM22–10?

7. Should the establishment of a minimum amount of Interregional Transfer Capability for non-RTO regions differ from that for RTO regions? If so, how?

Panelists

- *Debra Lew, Ph.D.*, Associate Director, Energy System Integration Group
- *Aaron Bloom*, Executive Director, NextEra Energy Transmission, LLC
- *Laura Rauch*, Senior Director, Transmission Planning, Midcontinent Independent System Operator, Inc.
- *David Kelley*, Director of Seams and Tariff Services, Southwest Power Pool, Inc.
- *Saad Malik*, Director Reliability Planning, Western Electricity Coordinating Council
- *Deral Danis*, Senior Director, Transmission, Pattern Energy Group LP
- *Sharon Segner*, Senior Vice President of Transmission Policy, LS Power Development, LLC

4:55 p.m.–5:00 p.m.: Closing Remarks

Day Two: Tuesday, December 6, 2022

12:00 p.m.–12:10 p.m.: Welcome and Opening Remarks

12:10 p.m.–2:15 p.m.: Panel 3: Process for Establishing Potential Interregional Transfer Capability Requirements

This panel will discuss the process for determining a minimum amount of Interregional Transfer Capability including, but not limited to, the determination of key data inputs, modeling techniques, and relevant metrics.

This panel may include a discussion of the following topics:

1. What process should be used to determine a minimum amount of Interregional Transfer Capability? For example, should the minimum be (a) derived heuristically from past extreme events; (b) derived using a probabilistic approach; or (c) based on scenario planning similar to the requirements proposed for Long-Term Regional Transmission Planning (Docket No. RM21–17–000) or other deterministic analysis? What are the advantages and disadvantages of each approach?

a. With respect to a probabilistic approach, what are the primary challenges in developing probabilistic models to determine a minimum amount of Interregional Transfer Capability? Do current probabilistic methods model common mode outages appropriately? If not, to what extent does that reduce the usefulness of a probabilistic approach?

b. With respect to scenario planning to determine a minimum amount of Interregional Transfer Capability, what guidelines, if any, are necessary to ensure that such scenario planning adequately assesses the need for, and value of, increased Interregional Transfer Capability? Are certain types of scenarios particularly important to assess the need for, and value of, Interregional Transfer Capability? Should scenario planning account for wide-area events and correlated outages, and if so, how?

2. After a need for a minimum amount of Interregional Transfer Capability is determined, what models and data are necessary to evaluate it? Do public utility transmission providers typically have access to or collect these models and data? If not, how should public utility transmission providers acquire these models and data? To simulate the wide-area impact of extreme events, to what extent should these models and data represent the overall interconnection?

3. What criteria should be used to assess whether public utility transmission providers have sufficient existing transmission facilities to meet or surpass an Interregional Transfer Capability requirement? Please specify whether your answer to this question depends on your answer to question 1 in this panel.

a. Is there a benefit to using a specific metric of Interregional Transfer Capability? Potential metrics may include a set amount of electric power, an amount of electric power relative to some electric power characteristic of the transmission planning region (like peak load, or the largest single contingency), among others.

b. To what extent should public utility transmission providers in a transmission planning region consider criteria that would help ensure the ''right amount'' of Interregional Transfer Capability is identified and sufficient Transfer Transmission Facilities are selected to meet an Interregional Transfer Capability requirement? For example, should the criteria used to assess whether public utility transmission providers meet an Interregional Transfer Capability requirement be informed by the net-benefits, or other types of measures, of Transfer Transmission Facilities?

4. What operational barriers preclude potential Interregional Transfer Capability from being realized during normal and emergency system conditions?

Panelists

- *Sheila Manz, Ph.D.*, Technical Director, Decarbonization Planning, GE Energy Consulting
- *Digaunto Chatterjee*, Vice President, System Planning, Eversource Energy
- *David Souder*, Executive Director, System Planning, PJM Interconnection, L.L.C. and Vice Chair, Eastern Interconnection Planning Collaborative Technical Committee
- *Michael Goggin*, Vice President, Grid Strategies, LLC, speaking on behalf of the American Clean Power Association
- *Nicolas Koehler*, Director, Transmission Planning, American Electric Power Company
- *Christopher Clack, Ph.D.*, Chief Executive Officer, Vibrant Clean Energy, LLC

2:15 p.m.–2:30 p.m.: Break

2:30 p.m.–4:45 p.m.: Panel 4: Meeting the Goal of Increased Interregional Transfer Capability

This panel will discuss how costs for Transfer Transmission Facilities should be allocated and how to ensure a minimum amount of Interregional Transfer Capability is achieved and maintained.

This panel may include a discussion of the following topics:

1. How should cost allocation for Transfer Transmission Facilities be determined? For example, should public utility transmission providers in a transmission planning region be required to allocate the costs of Transfer Transmission Facilities: (1) within their own transmission planning region; (2) jointly with two or more neighboring transmission planning regions; (3) at an Interconnection-wide level; or (4) via some other process? What are the advantages or disadvantages of each approach? Should there be a process in place for the Commission to establish a cost allocation method for Transfer Transmission Facilities if the public utility transmission providers in (1), (2), or (3) above cannot agree?

a. How should the process for evaluating, selecting, and allocating the costs of Transfer Transmission Facilities align with current regional transmission planning and interregional transmission coordination processes (*e.g.,* should the process be a part of existing transmission planning and cost allocation and/or coordination and cost allocation processes or should it be a separate process)?

2. How would public utility transmission providers in a transmission planning region demonstrate that they have met the minimum Interregional Transfer Capability requirement?

3. What process would public utility transmission providers in (a) a transmission planning region, (b) a pair of transmission planning regions, or (c) a broader collection of neighboring planning regions use to identify and select Transfer Transmission Facilities?

4. Should the Commission reexamine the minimum Interregional Transfer Capability requirement or the required process to identify and select Transfer Transmission Facilities at some point in the future (*e.g.,* in 10 years)?

5. What, if any, categories of benefits should public utility transmission providers be required to consider when evaluating Transfer Transmission Facilities for selection for purposes of cost allocation?

a. Should the benefits considered be consistent between (a) public utility transmission providers in each pair of neighboring transmission planning regions, (b) the public utility transmission providers in all of a transmission planning region's neighboring transmission planning regions, or (c) all public utility transmission providers within an Interconnection? What are the advantages and disadvantages of each approach?

6. Should the Commission prescribe a standard, or principles to govern the selection of Transfer Transmission Facilities for purposes of cost allocation?

7. Should the Commission require public utility transmission providers to use a portfolio approach for selecting Transfer Transmission Facilities to meet a minimum amount of Interregional Transfer Capability?

8. What rules, if any, should the Commission promulgate with regard to establishing a cost allocation method for Transfer Transmission Facilities?

a. What are the advantages and disadvantages of the Commission requiring a specific *ex ante* regional and/or interregional cost allocation method for Transfer Transmission Facilities?

b. What are the advantages and disadvantages of the Commission requiring a specific *ex post* regional and/or interregional cost allocation method or a hybrid (*i.e.,* part *ex ante* and part *ex post*) for Transfer Transmission Facilities?

c. Should the Commission decline to prescribe an *ex ante* or *ex post* cost allocation method for applicable public utility transmission providers, what process should govern the establishment of cost allocation rules for any particular Transfer Transmission Facility?

9. What role should state and local governmental entities play in the public utility transmission provider process for selection and cost allocation for Transfer Transmission Facilities? Should the states' role in selection and cost allocation be determined by the drivers of the need for a minimum requirement for Transfer Transmission Facilities? For example, if the Transfer Transmission Facilities are planned to serve public policy goals, such as renewable generation deployment, should the states have a role in cost allocation, such as that proposed in the Notice of Proposed Rulemaking in RM21–17?

10. Are there barriers to the ability of interregional merchant transmission facilities in providing a minimum amount of Interregional Transfer Capability? For example, do contractual or tariff limitations prevent merchant interregional high-voltage direct current transmission facilities from supporting reliability during extreme events?

Panelists

- *Kris Zadlo*, Chief Development Officer, Grid United
- *Travis Kavulla*, Vice President Regulatory Affairs, NRG Energy, Inc.
- *Shashank Sane*, Executive Vice President, Transmission, Invenergy
- *Rob Gramlich*, Founder and President, Grid Strategies, LLC
- *Andrew French*, Commissioner, Kansas Corporation Commission
- *J. Arnold Quinn*, Chief Economist, Vistra Corp.

4:45 p.m.–5:00 p.m.: Closing Remarks

[FR Doc. 2022–26474 Filed 12–5–22; 8:45 am]

BILLING CODE 6717–01–P

## FEDERAL DEPOSIT INSURANCE CORPORATION

### Notice of Termination of Receiverships

The Federal Deposit Insurance Corporation (FDIC or Receiver), as Receiver for each of the following insured depository institutions, was charged with the duty of winding up the affairs of the former institutions and liquidating all related assets. The Receiver has fulfilled its obligations and made all dividend distributions required by law.

NOTICE OF TERMINATION OF RECEIVERSHIPS

| Fund | Receivership name | City | State | Termination date |
|---|---|---|---|---|
| 10005 | ANB Financial, NA | Bentonville | AR | 12/01/2022 |
| 10012 | Integrity Bank | Alpharetta | GA | 12/01/2022 |
| 10037 | Corn Belt Bank & Trust Company | Pittsfield | IL | 12/01/2022 |
| 10061 | Bankunited, FSB | Coral Gables | FL | 12/01/2022 |
| 10131 | Hillcrest Bank Florida | Naples | FL | 12/01/2022 |
| 10220 | Citizens Bank & Trust Company of Chicago | Chicago | IL | 12/01/2022 |
| 10330 | The Bank of Asheville | Asheville | NC | 12/01/2022 |
| 10336 | American Trust Bank | Roswell | GA | 12/01/2022 |
| 10531 | THE Enloe State Bank | Cooper | TX | 12/01/2022 |

The Receiver has further irrevocably authorized and appointed FDIC-Corporate as its attorney-in-fact to execute and file any and all documents that may be required to be executed by the Receiver which FDIC-Corporate, in its sole discretion, deems necessary, including but not limited to releases, discharges, satisfactions, endorsements, assignments, and deeds. Effective on the termination dates listed above, the Receiverships have been terminated, the Receiver has been discharged, and the Receiverships have ceased to exist as legal entities.

(*Authority:* 12 U.S.C. 1819)

Federal Deposit Insurance Corporation.

Dated at Washington, DC, on December 1, 2022.

**James P. Sheesley,**

*Assistant Executive Secretary.*

[FR Doc. 2022–26505 Filed 12–5–22; 8:45 am]

BILLING CODE 6714–01–P

## FEDERAL HOUSING FINANCE AGENCY

**[No. 2022–N–15]**

### Proposed Collection; Comment Request

**AGENCY:** Federal Housing Finance Agency.

**ACTION:** 60-Day notice of submission of information collection for approval from Office of Management and Budget.

**SUMMARY:** In accordance with the requirements of the Paperwork Reduction Act of 1995 (PRA), the Federal Housing Finance Agency (FHFA) is seeking public comments concerning an information collection known as the ''National Survey of Mortgage Originations'' (NSMO), which has been assigned control number 2590–0012 by the Office of Management and Budget (OMB). FHFA intends to submit the information collection to OMB for review and approval of a three-year extension of the control number, which is due to expire on June 30, 2023.