UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Interconnection of Large Loads to the Interstate Transmission System	**)** **)**	**Docket No. RM26-4-000**

INITIAL COMMENTS OF NRG ENERGY, INC.

In accordance with the October 27, 2025 and November 7, 2025 notices of the Federal Energy Regulatory Commission (the "Commission" or "FERC"),[1] NRG Energy, Inc. ("NRG") submits initial comments on the advance notice of proposed rulemaking (the "ANOPR") on large load interconnection released by the Secretary of Energy (the "Secretary").[2] NRG strongly supports the principles set forth in the ANOPR but proposes several discrete modifications to ensure that the final rule successfully implements those principles. Specifically, NRG proposes that the final rule: (1) establish a rebuttable presumption that any load interconnection at 230 kV or above is a large load interconnection subject to the standardized interconnection process contemplated by the NOPR; (2) not include the proposed 20 MW size restriction on large load interconnections; (3) provide for the use of open seasons to expedite large load interconnections and to efficiently allocate interconnection capacity to such interconnections; (4) incorporate the ANOPR principle that load and hybrid facilities should be responsible for 100 percent of the network upgrade costs caused by their interconnections; and (5) ensure that the implementation of

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[1] *Interconnection of Large Loads to the Interstate Transmission Sys.*, Notice Inviting Comments, Docket No. RM26-4-000 (Oct. 27, 2025) (unreported); *Interconnection of Large Loads to the Interstate Transmission Sys.*, Notice Granting Extension of Time, Docket No. RM26-4-000 (Nov. 7, 2025) (unreported).

[2] *Interconnection of Large Loads to the Interstate Transmission Sys.*, Advanced Notice of Proposed Rulemaking, Docket No. RM26-4-000 (Oct. 27, 2025) (unreported) (the "ANOPR").

the final rule respects and preserves the rights of large loads that have already made significant commitments under state-prescribed interconnection procedures.

Executive Summary

NRG strongly supports the ANOPR but is concerned that without the modifications proposed herein, critical elements of the ANOPR could become a dead letter or could create more of the delays and uncertainty that the ANOPR is meant to eliminate. NRG urges the Commission to adopt the proposed modifications so that ANOPR will achieve its stated and laudatory goal of "ensur[ing] the timely and orderly interconnection of large loads to the transmission system."[3]

***First**, the Commission should adopt a rebuttable presumption that any load interconnection at 230 kV or above is a large load interconnection subject to the standardized interconnection process contemplated by the NOPR.* The ANOPR proposes to limit the Commission's assertion of jurisdiction over large load interconnections "to interconnections directly to transmission facilities" in order "to avoid *even arguably* affecting the States' jurisdiction over generation facilities, facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or transmissions consumed by the transmitter . . . ."[4] NRG's concern is that relying solely on the Commission's seven-factor test, as contemplated by the ANOPR,[5] could lead to a lengthy, opaque, litigious, and uncertain process to determine whether an interconnection is at the transmission level that would result in exactly the sort of uncertainty and delay the ANOPR is meant to avoid. A rebuttable presumption that a proposed load interconnection at 230 kV or above is a large load interconnection to a transmission facility would avoid these pitfalls.

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3 *Id.* at P 1 (footnote omitted).

4 *Id.* at P 18 (emphasis in original).

5 *See id.*

***Second**, the final rule should not include the proposed 20 MW size restriction on large load.* The 20 MW size restriction appears to be arbitrary and is, in any event, unnecessary. In NRG's experience, small loads, such as residential and small commercial customers, do not interconnect with transmission facilities, and there is no logical reason why a 19 MW load interconnecting at the transmission level should be required to proceed under state-regulated interconnection procedures while a load just one megawatt larger would be under Commission-prescribed procedures. In NRG's experience, large customers often begin as small loads on the system before scaling up, and a size threshold such as that proposed by the ANOPR could trap certain loads in an awkward jurisdictional gap that is, instead, best resolved by determining those facilities that are properly classified as transmission as NRG suggests in its first modification proposing a rebuttable presumption to classify facilities above 230-kV as transmission.

***Third**, the Commission should mandate the use of open seasons to expedite large load interconnections and efficiently allocate interconnection capacity*. While the Commission's past rules standardizing the generator interconnection process have properly vindicated the need for non-discriminatory open access,[6] their allocation of interconnection capacity in whole or in part based on when a generator requests service has produced hopelessly snarled queues filled with speculative requests. A more efficient, market-based approach employing open seasons would provide much needed certainty around the amount and location of large loads, which would benefit regional transmission system operators ("RTOs")/independent system operators ("ISOs"),

[6] *See Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 104 FERC ¶ 61,103 (2003) ("Order No. 2003"), *on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 (2004), *on reh'g*, Order No. 2003-B, 109 FERC¶ 61,287 (2004), *on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054 ("Order No. 2023"), *on reh'g*, 185 FERC ¶ 61,063 (2023), *on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199 (2024).

transmission owners, generators and consumers alike by facilitating more orderly planning and capital investment. Such processes have been used successfully for decades by FERC-jurisdictional natural gas pipelines and in other industries and have also been used successfully on electric transmission systems, such as the Alberta Electric System Operator ("AESO"), which recently conducted a process to allocate existing system headroom to data centers.

***Fourth**, the Commission should adopt the ANOPR principle that load and hybrid facilities should be responsible for funding, at least initially, 100 percent of the network upgrade costs caused by their interconnections.* This approach is consistent with the Commission's longstanding approach with respect to generator interconnections. Applying this same principle to load interconnections would represent a marked improvement on approaches taken in some states, which create significant risks that existing, captive customers will be forced to subsidize large loads.

***Fifth**, the Commission should establish an implementation plan that respects and preserves the rights of large loads that have already made significant commitments under state-regulated tariffs.* Consistent with the stated goal of providing greater certainty and avoiding delay with respect to large load interconnections and in keeping with the Commission's past practice when implementing major regulatory initiatives, the final rule should ensure that large loads whose interconnections are already being studied under state-regulated tariffs are not forced to start over and instead have their option of continuing down a path associated with the *status quo ante* or, alternatively, under the Commission's new approach.

I. About NRG

NRG is an integrated power company that serves more than 8 million customers through its power, gas and energy-and-home-services retail brands and that owns and operates more than 10 GW of power generation. NRG also operates a large demand-response company.

Specifically, as relevant to this proceeding, NRG is actively pursuing the redevelopment of power-generation sites for data-center deployment. Commercial operations are expected to begin in 2028 with ramping through 2032. NRG has also announced a joint venture to develop more than 5 GW of new natural gas-fired generation with GE Vernova and the EPC contractor Kiewit to rapidly bring new generation capacity online in response to growing demand from AI.[7] NRG has so far reported 445 MW of power purchase agreements to support new large load customers. Through these developments, NRG is strengthening its platform and is well positioned to meet rising customer demand and support large load growth.

II. Comments

A. The Final Rule Should Establish a Bright-Line Voltage Test for Application of the Large Load Interconnection Procedures[8]

In order to avoid any intrusion on state jurisdiction, the ANOPR proposes that the Commission would only assert jurisdiction over large load "interconnections directly to transmission facilities, *consistent with the Commission's seven-factor test*."[9] NRG is concerned that exclusive reliance on the seven-factor test could engender just the sort of uncertainty and delay that the ANOPR seeks to avoid. To provide greater certainty and avoid unnecessary delay, NRG

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[7] *See* NRG, *NRG Energy, GE Vernova and Kiewit Accelerating New Generation Capacity to Support Demand Growth* (Feb. 26, 2025), https://www.nrg.com/about/newsroom/2025/44211.html.

[8] This subsection relates to the ANOPR's first principle, that "the Commission's jurisdiction should be limited to interconnections directly to transmission facilities, consistent with the Commission's seven-factor test." ANOPR at P 18 (footnote omitted).

[9] ANOPR at P 18 (emphasis added).

proposes that the Commission adopt a rebuttable presumption that all load interconnections at 230 kV or above are large load interconnections directly to transmission facilities.

In Order No. 888, the Commission stated its intent to defer to state regulators' "determinations as to which facilities are transmission and which are local distribution, provided that the states, in making such determinations, apply the [following] seven criteria":[10]

> (1) Local distribution facilities are normally in close proximity to retail customers.
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> (2) Local distribution facilities are primarily radial in character.
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> (3) Power flows into local distribution systems; it rarely, if ever, flows out.
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> (4) When power enters a local distribution system, it is not reconsigned or transported on to some other market.
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> (5) Power entering a local distribution system is consumed in a comparatively restricted geographical area.
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> (6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.
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> (7) Local distribution systems will be of reduced voltage.[11]

The purpose of this seven-factor test is to assess the "primary function of a facility," which, in turn, "determines whether the facility is under [FERC's] jurisdiction."[12]

While Order No. 888 largely left the work of adjudicating the line between transmission and distribution under the seven-factor test to state commissions,[13] the Commission has itself

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[10] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, 75 FERC ¶ 61,080, FERC Stats. & Regs. ¶ 31,036, 61 Fed. Reg. 21540-01, 21625 (1996) ("Order No. 888"), *on reh'g*, Order No. 888-A, 78 FERC ¶ 61,220, FERC Stats. & Regs. ¶ 31,048, *on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Poly Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[11] *Id.* at 21620 (footnote omitted).

[12] *California Pac. Elec. Co., LLC*, 133 FERC ¶ 61,018 at P 45 (2010) ("*CalPeco*").

[13] Order No. 888, 61 Fed. Reg. at 21625.

applied the test on a number of occasions.[14] As the Commission knows, application of the seven-factor test can be complex and time-consuming. Indeed, in a number of the cases where the Commission has been tasked with applying the test, the issues have been sufficiently complex as to require hearing procedures, with the result that full adjudication of the issues has taken years. Even when no hearing has been required, the seven-factor test has left the Commission and the parties to grapple with complex and murky questions, including attempting to divine whether a particular facility "more closely resemble[s]" a set of similarly sized facilities classified by a state commission as distribution facilities or another set classified by the state commission as transmission facilities.[15]

While less burdensome on the Commission, state decision-making in this area has been no more rapid or less uncertain. In practice, since being established in Order No. 888, the seven-factor test has proven to be subjective, opaquely administered, and decided in the first instance by utilities that will have their own motivations for making certain functionalization decisions. No map or other public resource readily exists to reflect the jurisdictional separations that exist, and substantial analysis under the seven-factor test would have to occur in order to implement this rule, if the seven-factor factor test were principally relied upon. Exclusive reliance on the seven-factor test to determine whether a facility with which a large load seeks to interconnect is transmission risks creating a long series of time consuming and unproductive disputes about the taxonomy of facilities, which would frustrate the Secretary's intent to provide for the "timely and orderly

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[14] *See, e.g.*, *Red Hills AssetCo LLC*, 191 FERC P 61117 (2025); *Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 580, 181 FERC ¶ 61,056 (2022); *DTE Elec. Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,222 (2022) ("*DTE*"); *Southwest Power Pool, Inc.*, Opinion No. 579, 180 FERC ¶ 61,192 (2022); *Southern Cal. Edison Co.*, 153 FERC ¶ 61,384 (2015); *MidAmerican Energy Co.*, 140 FERC ¶ 61,028 (2012); *CalPeco*, 133 FERC ¶ 61,018.

[15] *DTE*, 180 FERC ¶ 61,222 at P 47.

addition of large loads to the transmission system in a safe, reliable, and non-discriminatory manner."[16]

In exercising its responsibilities for the facilities to which federal reliability standards should apply, the Commission recognized the need for greater certainty and uniformity about the line between transmission and distribution in proposing to order the North American Electric Reliability Corporation ("NERC") to revise its definition of "bulk electric system" to include "all transmission facilities at 100 kV or above, except for radial transmission facilities serving only load," with a process for NERC to grant facility-specific exceptions subject to Commission review.[17] The Commission approved NERC's proposal to "establish[] a bright-line threshold that includes all facilities operated at or above 100 kV,"[18] with certain specific exclusions.[19] Among other things, NERC excluded any radial system that (1) only serves load, (2) only includes generation resources with an aggregate capacity not exceeding 75 MVA, or (3) serves load and includes generation resources with an aggregate non-retail capacity of 75 MVA or less.[20] After initially proposing to let NERC decide "if and how the Seven Factor Test should be considered in differentiating between local distribution and transmission facilities,"[21] the Commission ultimately concluded that it was "more appropriate that the Commission make such case-by-case jurisdictional determinations when necessary, and to apply the Seven Factor Test set forth in Order

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16 ANOPR at P 24.

17 *Revision to Elec. Reliability Org. Definition of Bulk Elec. Sys.*, Notice of Proposed Rulemaking, 130 FERC ¶ 61,204 at P 18 (2010).

18 *Revisions to Elec. Reliability Org. Definition of Bulk Elec. Sys. & Rules of Proc.*, Order No. 773, 141 FERC ¶ 61,236 at P 1 (2012) ("Order No. 773"), *on reh'g*, Order No. 773-A, 142 FERC ¶ 61,053 (2013).

19 *See id.* at P 18.

20 *See id.*

21 *Revision to Elec. Reliability Org. Definition of Bulk Elec. Sys.*, Order No. 743-A, 134 FERC ¶ 61,210 at P 70 (2011).

No. 888 to make such determinations."[22] Nonetheless, the 100 kV bright-line has provided needed clarity and predictability.

While NERC's definition excludes "radial transmission facilities,"[23] it is important to bear in mind that NERC is drawing the boundaries of the "bulk electric system" and not the jurisdictional lines. A radial transmission facility is, by definition, still a transmission facility, and to the extent such a facility transmits energy in interstate commerce, it is subject to the Commission's exclusive jurisdiction. Even where the boundaries of the "bulk electric system" are concerned, the potential reliability impacts of large loads are such that NERC itself is considering whether such loads, which are often interconnected with radial transmission facilities, should be subject to reliability standards.[24] Implicit in this evaluation is a recognition that reliability can be a two-way street, which further begs the question of whether radial transmission facilities that may be intended to serve large loads can be excluded from the definition of "bulk electric system."

In order to ensure that the final rule in this proceeding fulfils the ANOPR's goals, NRG urges the Commission to adopt a rebuttable presumption that any proposed load interconnection at 230 kV or above is a large load interconnection directly to a transmission facility and thus covered by the standardized interconnection procedures contemplated by the ANOPR. NRG recognizes that the Commission declined to adopt a voltage-based, bright-line test in Order No. 888, stating:

> [I]t would be preferable to draw an absolutely 'bright' line (e.g., based on technical characteristics such as voltage) but the Commission does not believe this is required by case law and, importantly, would not be a workable approach in all cases because

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22 Order No. 773, 141 FERC ¶ 61,236 at P 69.

23 *Id.* at P 1.

24 *See generally* NERC, *Characteristics and Risks of Emerging Large Loads: Large Loads Task Force White Paper* (July 2025), https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/3_doc_white-paper-characteristics-and-risks-of-emerging-large-loads.pdf.

> of the wide variety of circumstances that may arise and because utilities themselves classify facilities differently (e.g., one utility may classify a 69 kV facility as transmission; another may classify it as distribution).[25]

Significantly, what NRG is proposing is not an absolute, bright-line test but instead a rebuttable presumption that would complement, not displace, the seven-factor test. NRG's proposal is similar to the NERC approach in that it would establish a voltage-based test, while retaining the seven-factor test as a means both of rebutting the presumption that a particular facility of 230 kV is a transmission facility for purposes of the large load interconnection procedures and of showing that a facility of less than 230 kV is a transmission facility for this same purpose. The Commission and state regulators would still have the seven-factor test as a tool to address "the wide variety of circumstances that may arise" and the fact that "utilities themselves classify facilities differently . . . ."[26] At the same time, however, all concerned could have greater confidence about the rules for interconnecting at or above 230 kV.

To the best of NRG's knowledge, 230 kV is well above the highest voltage level of any facility classified by the Commission as distribution using the seven-factor test.[27] It is also significantly higher than NERC's bright-line of 100 kV. The proposed rebuttable presumption accords with the Commission's longstanding use of rebuttable presumptions as a means of streamlining administrative processes and avoiding unproductive and unnecessary disputes. For

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[25] Order No. 888, 61 Fed. Reg. at 21731.

[26] *Id.*

[27] As best NRG could determine, the highest voltage facilities classified by the Commission as distribution were certain 120 kV lines connecting the owner's distribution substations with another utility's transmission and distribution systems. *See CalPeco,* 133 FERC ¶ 61,018 at n.34. NRG is also aware of an order in which the Commission deferred to a state commission's finding that certain 161 kV lines were distribution facilities. *See MidAmerican Energy Co.,* 88 FERC ¶ 61,307 (1999).

example, the Commission's qualifying facility ("QF") regulations contain a number of different rebuttable presumptions, including rebuttable presumptions that:

- small power production facilities located more than one mile but less than 10 miles from each other are located at separate sites for purposes of the size restrictions on qualifying small power production facilities;[28]
- the thermal output of a new cogeneration of 5 MW is used in a productive and beneficial manner and is used fundamentally for industrial, commercial, residential or institutional purposes;[29] and
- a QF (except for a qualifying cogeneration facility with a capacity of 20 MW or less or a qualifying small power production facility with a capacity of 5 MW or less) has non-discriminatory access to a market if its eligible for service under a Commission-approved open access transmission tariff or reciprocity tariff and Commission-approved interconnection rules.[30]

Elsewhere, the Commission has adopted rebuttable presumptions about "control" for purposes of proceedings under Section 203 of the Federal Power Act,[31] the Commission's market-based rate program,[32] and the Standards of Conduct for Transmission Providers.[33] Among other things, the Commission has also established rebuttable presumptions that a market-based rate seller passing

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[28] *See* 18 C.F.R. § 292.204(a)(2)(C) (2024). There are also irrebuttable presumptions that facilities within one mile of each other are at the same site, 18 C.F.R. § 292.204(a)(2)(A) (2024), that facilities 10 miles or more from each other are at different sites, 18 C.F.R. § 292.204(a)(2)(D) (2024).

[29] *See* 18 C.F.R. § 292.205(d)(4) (2024).

[30] *See* 18 C.F.R. § 292.309(c) (2024).

[31] *See FPA Section 203 Supplemental Policy Statement*, 120 FERC ¶ 61,060 at P 57 (2007) ("[T]he Commission's general policy in future cases will be to presume that a transfer of less than 10 percent of a public utility's holdings is not a transfer of control if: (1) after the transaction, the acquirer and its affiliates and associate companies, directly or indirectly, in aggregate will own less than 10 percent of such public utility; and (2) the facts and circumstances do not indicate that such companies would be able to directly or indirectly exercise a controlling influence over the management or policies of the public utility.").

[32] *See* 18 C.F.R. § 35.36(a)(9)(v) (2024) ("For purposes of paragraph (a)(9), owning, controlling or holding with power to vote, less than 10 percent of the outstanding voting securities of a specified company creates a rebuttable presumption of lack of control.").

[33] *See* 18 C.F.R. § 358.3(a)(3) (2024) ("A voting interest of 10 percent or more creates a rebuttable presumption of control.").

both the indicative market power screens lacks horizontal market power[34] and that owning or controlling inputs to electric power production will not allow a seller to erect barriers to entry for market-based rate setting.[35]

The foregoing are but a few examples of how the Commission has employed rebuttable presumptions. The courts have found that rebuttable presumptions employed by federal agencies are lawful provided "a rational connection exists between the facts giving rise to a presumption and the fact presumed,"[36] and have held that the Commission may "adopt certain rebuttable presumptions via rulemaking, rather than by case-by-case adjudication."[37] Adoption by rulemaking of a presumption that an interconnection at 230 kV or above is with the transmission grid would be entirely appropriate and rationally connected to the fact that facilities of that voltage are rarely, if ever, classified as distribution facilities.

Over and above the administrative benefits of reducing reliance on the seven-factor test where large load interconnections are concerned, NRG's proposal serves to reduce the tension between the jurisdictional reach of the ANOPR and the Commission's approach to delineating between transmission and distribution facilities. Implicit in the seven-factor test is an assumption that use of a facility to serve retail customers weighs in favor of classification as distribution and not transmission. Indeed, the first, third, fourth and sixth prongs of the test are tied directly to

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34 *See* 18 C.F.R. § 35.37(c)(1) (2024).

35 *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils.*, Order No. 697-A, 123 FERC ¶ 61,055 at P 1018, *clarified*, 124 FERC ¶ 61,055, *on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *on reh'g*, Order No. 697-C, 127 FERC ¶ 61,284 (2009), *on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010), *clarified*, 131 FERC ¶ 61,021 (2010), *aff'd sub nom. Montana Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011).

36 *Atchison, Topeka & Santa Fe Railway Co. v. ICC*, 580 F.2d 623, 629 (D.C. Cir. 1978).

37 *American Forest & Paper Ass'n v. FERC*, 550 F.3d 1179, 1183 (D.C. Cir. 2008).

retail sales and consumption.[38] As an initial matter, any such assumption was legally dubious even when Order No. 888 was issued and has only become more so with the passage of time. When addressing the line between natural gas transportation and distribution decades before the issuance of Order No. 888, the Supreme Court found pipeline pressure, whose electric analog is voltage, to be the relevant consideration, stating:

> That th[e] continuous flow of gas from other states to and through [a gas utility]'s high-pressure lines constitutes interstate transportation has been established by numerous previous decisions of this Court. The gas does not cease its interstate journey the instant it crosses the Ohio boundary or enters [the utility]'s pipes, even though that Company operates completely within the state where the gas is finally consumed.[39]

The Supreme Court found the fact that the utility "sells gas direct to consumers rather than for resale" to be "immaterial" to the classification question.[40]

As regards the ANOPR, applying a test so tied to retail sales and consumption is, at the very least, in tension with the premise that the Commission has jurisdiction over large load interconnections notwithstanding the fact that the large load will be an end-use customer. In the ANOPR, the Secretary properly recognizes that "asserting jurisdiction over the interconnection of large loads to the transmission system" in no way conflicts with state jurisdiction "over any retail sales to the large load,"[41] which will remain subject to state regulatory oversight. Exclusive reliance on a seven-factor test that implicitly proceeds from the very different premise that the

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[38] Order No. 888, 61 Fed. Reg. at 21620 (footnote omitted).

[39] *FPC v. East Ohio Gas Co.*, 338 U.S. 464, 467 (1950) ("*East Ohio*"). East Ohio was effectively overruled as it relates to natural gas pipelines by the Hinshaw Amendment to the Natural Gas Act of 1938. *See Public Utils. Comm'n of Cal. v. FERC*, 900 F.2d 269, 292 n.4 (D.C. Cir. 1990). No corresponding amendment to the FPA has been enacted.

[40] *East Ohio*, 338 U.S. at 473. *See also id.* at 482 (Jackson, J., dissenting) (describing the majority as finding "the difference between retail and wholesale operations . . . immaterial, so long as the factor of high-pressure pipe lines is present").

[41] ANOPR at P 15.

nature of the facility is to be determined, in large part, based on whether it is used to effect retail sales is, at a minimum, legally awkward.

The seven-factor test's focus on retail sales and consumption as indicative of a distribution function is not only legally dubious but also dated. The impetus behind the ANOPR is the reality that large loads are interconnecting with the transmission system. Those large loads are purchasing at retail and consuming, and a test that presumes that such retail purchases and consumption are relevant to the line between transmission and distribution is questionable in today's hyperscaling era.

B. The 20 MW Size Restriction Appears Arbitrary and Is Unnecessary[42]

The 20 MW size restriction appears to be arbitrary. This figure appears to have been selected as the threshold for large loads because it is the threshold for large generators subject to the Commission-prescribed large generator interconnection procedures, rather than the small generator interconnection procedures. As an initial matter, it is not clear why the same threshold would be appropriate for distinguishing between small and large loads. More importantly, in the generation setting, the 20 MW line has no jurisdictional significance. The Commission exercises jurisdiction over both small and large generator interconnections with the transmission system (as well as interconnections with the distribution system for purposes of making wholesale sales); the only difference is which set of Commission-prescribed procedures apply. There is no logical reason why the interconnection of a 19 MW load to the transmission system should be considered state-jurisdictional while the interconnection of a 20 MW load to the transmission system is recognized as being subject to the Commission's exclusive jurisdiction. An exclusion based on

[42] This subsection relates to the ANOPR's second principle, that "the reforms should only apply to new loads greater than 20 MW and, for hybrid facilities, where the load is greater than 20 MW." ANOPR at P 19.

size is at odds with the principal jurisdictional basis for the rule: the Commission's exclusive jurisdiction over transmission in interstate commerce.

In any event, this size restriction is unnecessary. This restriction is presumably intended to avoid the assertion of Commission jurisdiction over the interconnection of small loads, such as residential and small commercial customers. In NRG's experience, however, such a customer is not going to interconnect with any facility classified as transmission, and a customer intending to be sized above 20 MW would *never* interconnect at 230 kV or above, which NRG proposes as a threshold for a rebuttable presumption applicable to the classification of the transmission system for the purposes of the regulation that results from the instant proceeding. Moreover, the size restriction will be administratively problematic, because there are likely to be data centers and other large loads whose initial size will be below the 20 MW threshold but which will ramp up in size over time. Based on NRG's experience with similar size restrictions on eligibility for retail choice programs, NRG would be concerned that such loads could be trapped under state-jurisdictional interconnection rules even after they were well above the 20 MW threshold.

C. The Final Rule Should Mandate the Use of Open Seasons to Allocate Interconnection Capacity to Large Load Interconnections[43]

Current load interconnection queues, like current generator interconnection queues, include a significant number of speculative projects that will never be developed. There is an

[43] This subsection relates to various of the ANOPR's principles, specifically:

- the fifth principle (because it confers a property interest to bidders for interconnection to transmission associated with "the amount of injection and/or withdrawal rights requested" that avoids the inefficiencies and lack of market price signals that characterize the serial interconnection queue),
- the third and seventh principles (because it is a means by which curtailable loads and hybrid facilities and those which bring interrelated resources to the system may be studied in recognition of the net system impacts they impose,

urgent need for a regulatory approach that prioritizes and expedites projects using a market-based function, rather than one based on timing of interconnection requests, administrative guesses around project quality, and financial commitments that are not necessarily aligned to the highest and best use of the grid. The ANOPR will not have fulfilled its goals and risen to this critical moment if it merely transfers jurisdiction over dysfunctional load queues from state commissions to FERC or drags large loads into the dysfunction of the generator interconnection queues.

While Order No. 888 took a critical step forward by unbundling and providing for non-discriminatory open access to Commission-regulated transmission services, it also established the precedent for allocating valuable transmission capacity on a first-come, first-served basis[44] that was then carried over to generator interconnection service in Order No. 2003, with its focus on queue position.[45] While these rules were enormously successful in opening up the grid and unlocking a huge amount of investment in the power sector, the first-come, first-served principle has produced snarled interconnection queues, filled with speculative puts on generation projects that will never be developed, and resulted in lengthy delays. While Order No. 2023 has attempted

- the fourth principle (because an open season avoids the administrative speculation at the heart of the bureaucracy of administering a serial interconnection queue, and instead concretely solves the problem of "deter[ing] speculative projects and provid[ing] transmission providers with more useful information to more accurately forecast demand on their systems"; and
- the eighth principle, because an open season is a self-contained and economically efficient approach for the direct assignment of costs based on the value of interconnection, which necessarily will return at least adequate and likely surplus revenue to the transmission revenue requirement. ANOPR at PP 20-25.

As discussed herein, the purposes of the ANOPR will not be fully achieved if the first-in-time, first-in right approach to generator interconnection is carried over to large load interconnection.

[44] *See* Order No. 888, 61 Fed. Reg. at 21605.

[45] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 35 ("Queue Position is used to determine the order of performing the various Interconnection Studies and the assignment of cost responsibility for the construction of facilities necessary to accommodate the Interconnection Request.").

to reduce the backlogs by moving from a serial study process to a cluster-based study process[46] and establishing financial penalties for utility foot-dragging,[47] the allocation of valuable interconnection capacity continues to be allocated primarily on the basis of when a project enters the queue.

The problems engendered by the first-come, first-served process have, in turn, prompted numerous interventions designed to expedite the interconnection of projects administratively determined to be more valuable or more ready by bypassing the normal queue procedures.[48] As the signatory to these comments and the chair of the Colorado Public Utilities Commission have jointly written in a recent publication, the status quo of generator interconnection procedures has at its core a failure to efficiently make use of the resource that is interconnectivity to the grid because of its conception of the system as a commons to which a first-in-time, first-in-right staking of a claim remains the conception of open access.[49] The Commission should take care not to replicate that failure with respect to large load interconnection.

Similar to generator interconnection, and perhaps even more dramatically, large load interconnection queues at the state level are stockpiled with speculative projects that will never be developed. That many of these projects will never be built is illustrated by the fact that in the Electric Reliability Council of Texas ("ERCOT") region, the data center growth reflected in load

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[46] *See* Order No. 2023, 184 FERC ¶ 61,054 at P 5.

[47] *See id.* at P 6.

[48] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 at P 1 (2025) (accepting expedited study process "to address urgent resource adequacy and reliability needs in the near term"); *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 at P 1 (accepting one-time expansion of study queue cluster for "up to 50 additional projects . . . to address near-term resource adequacy concerns"), *on reh'g*, 192 FERC ¶ 61,085 (2005); *Midcontinent Indep. Sys. Operator, Inc.*, 191 FERC ¶ 61,131 at P 198 (2025) (rejecting proposed expedited study process for projects claimed to be "shovel ready").

[49] *See* Eric Blank & Travis Kavulla, The End of the Grid's Gold Rush Era: Toward Customer-Oriented Approaches to Generator Interconnection, *EBA Brief* (Fall 2025) ("Gold Rush"), https://www.eba-net.org/wp-content/uploads/2025/08/EBA-Brief-2025-Vol-1.pdf.

forecasts greatly exceeds the availability of the microchips needed for those data centers.[50] Similarly, Constellation Energy Generation, LLC has compiled evidence showing that the combined data center load in forecasts prepared by ERCOT, PJM Interconnection, L.L.C. and the Midcontinent Independent System Operator, Inc., which collectively represent less than half of U.S. power demand, is double the average of third-party forecasts of nationwide demand center growth, which strongly suggests that the same data center projects are being pursued in multiple jurisdictions.[51]

This is hardly surprising, because like the Commission's generator interconnection procedures, state load interconnection rules largely prioritize competing requests based on queue position, which encourages speculative requests that inflate load forecasts and delay processing of more serious projects. To be fair, there have been some worthy reforms undertaken at the state level to weed out speculative requests. For example, in July 2025, the Public Utilities Commission of Ohio (the "PUCO") approved a settlement establishing additional requirements, including heightened collateral requirements, for large data center interconnections, in an effort to promote "right-sizing buildout and encouraging accurate forecasting" to "prevent[] wastefulness and stranded investment costs" that will impose "costs onto non-data center customers."[52] In its order, the PUCO noted the actions of other state regulators, including the Indiana Utility Regulatory

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[50] *See, e.g.*, James Downing, *GCPA Hears Different Tales on Texas Load Growth from 2 CEOs*, RTO Insider (Apr. 17, 2025) (quoting Calpine Corporation CEO's statement ERCOT's recent load forecast is "impossible because it's more than two times the amount of chips that Nvidia is expected to make over the next three years").

[51] *See* Pre-Technical Conference Comments of Constellation Energy Generation, LLC at 7, Docket No. AD25-7-000 (filed May 16, 2025).

[52] *In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers*, Opinion and Order at ¶ 123, Case No. 24-508-EL-ATA (July 9, 2025), https://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=badab793-e041-4173-9b6d-436e51f80e5c. *See also id.* at ¶ 117 (discussing other state actions cited by parties in support of the proposed settlement).

Commission (the "IURC") and the West Virginia Public Service Commission (the "WVPSC"), and found that "while not binding on the [PUCO]," these examples were "helpful and informative in determining that implementing a specially tailored customer class to address the [Ohio utility]'s transmission constraint concerns."[53] For their parts, the IURC and the WVPSC approved settlements establishing additional requirements, including minimum contract terms and increased collateral requirements, for large load customers.[54] The IURC explained that the settlement it approved would account for the "unprecedented size and unique risks" of large loads "protect [the utility] and its other customers."[55] These reforms will, like Order No. 2023, undoubtedly weed out some speculative projects. But like Order No. 2023,[56] they leave the traditional first-in-time, first-in-time approach to allocating expansion capacity in place.

A far better approach would be an open season or an auction mechanism that allocates capacity in a manner that maximizes the net present value ("NPV") of bids as understood through an efficient combination of relevant variables (*e.g.*, least cost, amount of incremental demand capable of being served, and speed to market). The Commission has the opportunity here to make a fresh start and establish a new policy in keeping with the regulation of a modern industry that is geared toward efficiency, speed, and cost discipline. Specifically, NRG proposes that the Commission mandate the use of open seasons to allocate load interconnection capacity. FERC-

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53 *Id.* at ¶ 121.

54 *In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff I.P.*, Order of the Commission, Cause No. 46097 (Feb. 19, 2024) ("IURC Order"), https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/2b48cf93-d9ee-ef11-be20-001dd80b8c52/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=ord_46097_021925.pdf; *Appalachian Power Co.*, Case No. 24-0611-E-T-PW (Mar. 25, 2025), https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=638931.

55 IURC Order at 48.

56 *See* Gold Rush at 3 (explaining that Order No. 2023 "did not fundamentally reform the first-in-time, first-in-right policy").

regulated interstate natural gas pipelines have long employed "open seasons to gauge demand for prospective expansion capacity . . . ."[57] That reflects the fact that in contrast to its historical reliance on first-in-time, first-in-right schemes to allocate generator interconnection capacity, "[t]he Commission's overriding policy for allocating pipeline capacity is to have capacity awarded to the highest valued use, that is, to those that value the capacity the most."[58]

Pipeline open seasons have successfully promoted capital formation using open seasons as part of a willing-buyer/willing-seller construct for decades. As the Commission has described it:

> Under this approach, and consistent with the terms of their tariffs, pipelines can conduct an open season announcing available capacity and stating criteria for an acceptable bid, the method for determining the best bid, and the bid closing date. Pipelines evaluate capacity bids submitted during the open season timeframe on a net present value (NPV) basis, which is the discounted cash flow of incremental revenues that the pipeline receives that are based upon such factors as the price, term, and quantity of transportation service.[59]

To be sure, as Chairman Blank and the undersigned observed, pipeline "physics lends itself to the ability to clearly delineate a right to transmit energy along a piece of point-to-point linear infrastructure," in contrast "to at least the alternating-current power grid's lattice-work, where

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[57] *Transcontinental Gas Pipe Line Co., LLC*, 190 FERC P 61048 at n.93 (2025) (citing *Trunkline Gas Co.*, 145 FERC ¶ 61,108 at P 22 (2013); *Southern Star Cent. Gas Pipeline, Inc.*, 102 FERC ¶ 62,165 at 64,273 (2003); *Southern Nat. Gas Co.*, 85 FERC ¶ 61,134 at 61,521 (1998)).

[58] *Maritimes & Ne. Pipeline, L.L.C.*, 154 FERC ¶ 61,084 at P 30 (2016). *See also, e.g., Texican N. La. Transport LLC v. Southern Nat. Gas Co.*, 130 FERC ¶ 61,167 at P 26 (2010) ("[T]he Commission's overriding policy for allocating pipeline capacity is to have capacity awarded to the highest valued use, that is, to those that value the capacity the most. The Commission's capacity allocation policy also is meant to promote the most efficient overall use of the pipeline system in a manner that maximizes benefits to the natural gas market. In furtherance of these goals, the Commission favors the use of open seasons to allocate capacity and NPV evaluations as a tool for determining the highest valued use.").

[59] *Petition for Rulemaking to Update Comm'n Regulations Regarding Allocation of Interstate Pipeline Capacity*, Notice of Inquiry, 186 FERC ¶ 61,197 at P 3 (2024) (footnotes omitted) (the "Pipeline Capacity NOI").

electrons flow fast and in often counterintuitive ways . . . ."[60] But it is equally true that reticulated natural gas pipelines,[61] whose systems are similarly non-linear, have also successfully employed open seasons.[62] Moreover, the Commission has allowed pipelines to conduct open seasons where shippers may be bidding on different combinations of pipeline segments, including non-contiguous and operationally unrelated segments,[63] which has the effect of making the bid analysis "non-linear" even if the pipeline system itself is linear.

There are several examples of open seasons being employed for capacity on electric transmission facilities. In FERC-jurisdictional markets, the majority of these open seasons have been for merchant direct current transmission facilities, which, as Rob Gramlich and Zach Zimmerman observed, "operate[] more like gas pipelines than integrated AC power networks."[64] At the same time, Messrs. Gramlich and Zimmerman also describe the use by the Bonneville Power Administration ("BPA") of a "Network Open Season" modeled on natural gas pipeline open seasons.[65] A key step in this open season had BPA performing an NPV analysis of precedent

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60 Gold Rush at 14. *See also* Rob Gramlich and Zach Zimmerman, Use of Network Open Seasons in the Electric Industry (Aug. 9, 2024) ("Network Open Seasons") ("Open seasons are less common in electricity mainly because of the properties of the grid where power flows freely across the integrated AC network. This free flow makes it harder for funders of new capacity to have exclusive rights to what they fund."), https://www.nrg.com/assets/documents/energy-policy/grid-strategies-electric-network-open-seasons080924.pdf.

61 *See In re: Columbia Gas Transmission, LLC*, 152 FERC ¶ 61,089 at P 3 (2015) (noting that the pipeline system of Columbia Gas Transmission, LLC ("Columbia") is "reticulated or web-like" which is "[u]nlike the typical FERC-jurisdictional pipeline which is longline is configuration").

62 *See, e.g., Columbia Gas Transmission, LLC*, 170 FERC ¶ 61,045 at P 8 (2020) (discussing open season for expansion capacity on Columbia's pipeline system).

63 Pipeline Capacity NOI, 186 FERC ¶ 61,197 at P 4.

64 Network Open Seasons at 1.

65 *See id.* at 2-5.

agreements with prospective interconnection and transmission delivery customers to determine if it could reasonably provide service to them at its existing embedded cost rates.[66]

In the same vein, the Alberta Electric System Operator ("AESO") recently conducted a process to allocate existing system headroom to data centers.[67] AESO began by establishing an interim, reliability-based, megawatt limit (1,200 MW) on large load interconnections with its grid[68] and then assigning that capacity to large loads ready to advance in the interconnection process[69] "a fair, efficient, and openly competitive manner"[70] based, in part, on each large load's "willingness to commit" through the posting of financial security.[71]

Auction mechanisms have, of course, been employed successfully in any number of other regulated industries. Perhaps most notable among these are the spectrum auctions conducted by the Federal Communications Commission (the "FCC"), whereby the FCC has used auctions to allocate spectrum licenses. These auctions "assign spectrum licenses to their highest and best use by allowing bidders to reveal their preferences and discover a market-clearing price."[72] The FCC has conducted such auctions for three decades, and they have "proven a resounding success . . . ."[73] Open seasons will almost certainly demand a more proactive role for grid planners than the

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66 *See id.* at 4.

67 *See* AESO, *Large Load Integration Phase I: Interim Connection Limit and Assignment* (June 4, 2025) ("AESO Presentation"), https://aesoengage.aeso.ca/48469/widgets/204062/documents/153825.

68 *See id.* at slides 23-30.

69 *See id.* at slides 32-38.

70 *Id*. at slide 34.

71 *Id*. at slide 35.

72 *Enhancing National Security Through the Auction of AWS-3 Spectrum Licenses; Applying New Average Annual Gross Revenue Benchmarks for Small Business Bidding Credits; Amendment of the Commission's Rules with Regard to Commercial Operations in the 1695-1710 MHz, 1755-1780 MHz, and 2155-2180 MHz Bands*, Report and Order and Second Report and Order, Report and Order at P 3, GN Docket No. 25-70, *et al.* (July 3, 2025).

73 *Id*. at P 3.

essentially reactive role they play under the first-in-time, first-in-right paradigm, but that should be helpful both to the interconnection process and the planning process. As Chairman Blank and the undersigned described an open season process for generator interconnection:

> Rather than devising a grid build-out in response to senior-most [interconnection request], a grid planner could plan an expansion that it reckoned was right-sized and cost-effective in view of the probable demand for interconnection—but then the planner's proposition would be tested (and ultimately funded) through the open season and interconnecting generators' willingness to sign up and pay for that right.[74]

In the large load setting, grid planners could assess the commercial interest in developing large loads in particular locations, tender a plan to the market to meet that demand, have large-load developers enter into financially binding commitments to receive an allocation of the capacity's cost, and then award the large load a property right to interconnect. Such an approach is geared toward speed-to-market, getting the most megawatts online at the lowest overall cost, and ensuring a direct allocation of incremental costs to new large users of the grid. Indeed, it is possible, even likely, that the bids of those seeking to obtain rights for large-load interconnections would exceed the revenue requirement of the incremental costs of the expansion, in which case the Commission and public utility in question could determine to rebate the excess to the overall transmission revenue requirement, turning demand growth into a clear benefit for other consumers.

A large load interconnection customer would have the right to withdraw energy at its point of interconnection to the transmission system comparable to the right of a generator interconnection customer's right to inject energy at its point of interconnection. The former closely resembles the rights of a shipper at the point of delivery on a natural gas pipeline system. NRG

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[74] Gold Rush at 14.

envisions the open season process for large load interconnection withdrawal rights proceeding as follows:

- Based on expressions of interest as demonstrated by current queues that exist at the state level, the transmission provider would develop an initial plan to interconnect large loads using existing system headroom and upgrades that can be completed on a short timeframe, appropriately segmented geographically.

- The transmission provider's initial plan would then be tested through a one-time open season that should be principally focused on speed to market and making use of existing headroom, if any, with any necessary upgrades limited to those that can be accomplished on a short timeline. This first open season should resolve on the basis that enables the greatest number of megawatts to obtain from the system relative to existing capacity.

    - This open season could be expected to reward those large loads with more flexible operations, either because of backup generation or flexible consumption.

    - The Commission should require each transmission provider conduct its initial, "headroom" open season no later than the first quarter of 2027.

- Subsequent open seasons or auctions should be held routinely for grid upgrades that require a greater level of incremental capital spending in terms of interconnection facilities and upstream network upgrades.

- The configuration of bidding large loads that returns the highest NPV is selected out of the open season or auction.

    - The NPV should be calculated in a manner that captures not only the price, term and quantity factors but also the value of serving more load sooner by accounting for the time to energize and the presence of hybrid loads. The Commission has previously found the consideration of similar factors in pipeline open seasons to be appropriate, accepting, for example, language providing that the pipeline will calculate NPV as "'the discounted cash flow of incremental revenues to [the pipeline] produced, lost or affected by the request for service' based upon such factors as the term, quantity, *requested service commencement date, [and the] cost of facilities required to provide service . . . .*"[75]

[75] *ANR Pipeline Co.*, 177 FERC ¶ 61,049 at P 2 (2021) (emphasis added). *See also Transcontinental Gas Pipe Line Corp.*, 118 FERC ¶ 61,234 at P 3 (2007) (accepting an NPV calculation for an open season that "t[ook] into account the time value of the delay in revenue under a bid for firm service to commence in the future").

- At least where RTOs/ISOs are concerned, the Commission might consider also granting additional discretion for the transmission provider to consider "other factors determined to be relevant by [the RTO/ISO]" subject to a posting of such factors prior to the open season.[76]

- To prevent unduly discriminatory and anticompetitive tying, the net present value of each bid should be calculated independently of revenue streams for other services, including transmission delivery and retail energy sales services, consistent with Commission precedent on pipeline open seasons.[77]

- Consistent with what has been required for pipeline open seasons, the Commission should require that transmission providers post the NPV analysis for the winning bid or the highest bid when there is no successful bid. As the Commission has stated, such posting "provide[s] added transparency and a check permitting [bidders] to confirm that capacity was awarded in a non-discriminatory fashion."[78]

- Large loads within this configuration are placed under a binding financial obligation and they obtain the right to interconnect and withdraw a certain amount of capacity at the point of interconnection, as contemplated in the ANOPR. Like the rights pipeline shippers enjoy under precedent agreements resulting from open seasons, these rights should be allowed to be traded on the secondary market in order to promote efficiency and capital formation. The right should have certain, limited usufructuary obligations, specifically that a load is actually drawing from the system at some point after it is electrically possible to do so in order to ensure a right to interconnect is not being hoarded.

- The bidders in the first two auctions (the "headroom" auction and the first incremental-investment auction) should have demonstrated that they already have projects submitted into the queue of their local electric distribution company, so as to attempt to streamline the implementation of the ANOPR's resulting regulation

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[76] *Id.* *See also Columbia Gas Transmission, LLC*, 148 FERC ¶ 61,218 at P 43 (2014) ("The Commission has previously allowed pipelines the leeway, in open season provisions, to either include in their tariff a single non-discriminatory bid evaluation methodology, or to provide themselves flexibility by choosing different non-discriminatory bid evaluation methods for different transactions, provided that the pipeline posts the bid evaluation methodology before the open season begins.").

[77] *See Williams Natural Gas Co.*, 62 FERC ¶ 61,261 at 62,760 (1993) (directing pipeline to remove provisions of right of first refusal process that would have "allow[ed the pipeline] to consider other offers to purchase other, unrelated capacity when evaluating the net present value of offers," which the Commission found to be "highly inappropriate because they unfairly discriminate against existing shippers").

[78] *Northern Border Pipeline Co.*, 164 FERC ¶ 61,150 at P 19 (2018). *See also, e.g.*, *ANR*, 177 FERC ¶ 61,049 at P 11 (stating that "the Commission has required pipelines to post the NPV analysis used to determine the successful bid after the close of the open season").

from the *status quo ante* of state regulation, which likely has unfolded as a serial-queue regime that rewards first-in-time requestors.

  - The open season or auction should consider as set aside any rights that have accrued to large loads that already have signed binding financial commitments under large load tariffs at the state level for purpose of interconnecting to transmission facilities at 230 kV and above.

- This open season or auction achieves a direct cost allocation of both interconnection and network upgrade costs, preventing cost shifts to other customers. Surplus revenue from the open season should be applied against the transmission owner's transmission revenue requirement, reducing costs for all other customers. Axiomatically, an open season either will be cost-neutral or cost-reducing to a transmission provider's other customers, ensuring that large loads deliver a net benefit to them. The revenue furnished by this open season or auction may be partially refunded over time as the large loads continue to pay ordinary stated rates for transmission service.

D. As the Secretary Proposed, Large Loads Should Fund, at Least Initially, 100 Percent of the Network Upgrade Costs Caused by their Interconnections[79]

NRG strongly supports the Secretary's proposed eighth principle for large load interconnection: that "load and hybrid facilities should be responsible for 100% of the network upgrades that they are assigned through the interconnection studies."[80] Such an approach would be consistent with the Commission's longstanding policy that "Network Upgrades will be funded initially by the Interconnection Customer (unless the Transmission Provider elects to fund them) . . . ."[81]

By contrast, many state policies fail to ensure that interconnecting loads are properly assessed the full cost of their interconnections with the transmission grid. In particular, many state-

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[79] This subsection relates to the ANOPR's eighth principle, that "load and hybrid facilities should be responsible for 100% of the network upgrades that they are assigned through the interconnection studies." ANOPR at P 25.

[80] ANOPR at P 25.

[81] Order No. 2003, 104 FERC ¶ 61,103 at P 22. Where the transmission provider is non-independent, the customer is then entitled to transmission credits equal to the total amount it paid for the network upgrades. *See id.*

regulated utilities seek a "revenue guarantee" based on embedded cost rates multiplied by the MW-demand of the data center for some length of time.[82] Sometimes called "minimum commitments," this provision has been advertised as a policy approach that causes data centers to pay their fair share of grid costs, which may suggest alignment with the eighth principle announced in the ANOPR, but this is not an accurate understanding of the details of the "revenue guarantee" or "minimum commitments" provisions which have so far been adopted by state commissions. As explained by James R. Dauphinais in testimony submitted to the Illinois Commerce Commission on NRG's behalf, these provisions aim at the wrong thing:

> [T]he transmission and distribution revenues guaranteed by a large load addition customer could be substantially more or substantially less the revenue requirement of the transmission and distribution investments that would not have been needed but for that customers' large load addition. If the guaranteed revenues are significantly higher than the revenue requirement, it would cause the large load addition customer to subsidize [the utility]'s existing customers because it would require the large load addition customer to guarantee revenues in excess of the costs incurred for that large load addition. If the guaranteed revenues are significantly lower than the revenue requirement, it would cause the [the utility]'s existing customers to subsidize the large load addition customer because it would not require the large load addition customer to guarantee revenues sufficient to cover the costs that were incurred for that large load addition.[83]

This disconnect not only threatens to have existing, captive customers subsidizing the new large load (or *vice versa*), it also "fail[s] to send a price signal for large load additions to locate in

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[82] *See, e.g.*, Direct Testimony and Exhibits of James R. Dauphinais on Behalf of NRG Energy, Inc. at 4, 13-17, Illinois Commerce Commission Docket Nos. 25-0677, *et al.* (filed Sept. 26, 2025) (testimony regarding revenue guarantee proposal by Commonwealth Edison Company), https://www.nrg.com/assets/documents/energy-policy/nrg-ex-1.0-direct-testimony-of-james-r-dauphinais-icc-docket-nos-25-0677-0679-comed-large-load-tariff-case.pdf.

[83] *Id.* at 13.

locations where the required transmission . . . investments for the large load would be lower."[84] This is poor public policy, and it is inconsistent with the Secretary's mandate for a just and reasonable process for the interconnection of large loads.

E. The Final Rule Should Respect and Preserve the Rights of Large Loads that Have Already Made Significant Commitments under State-Prescribed Interconnection Procedures[85]

As the Secretary and the Commission know all too well, data centers and other large loads have not waited for regulators or utilities to begin interconnecting with the transmission grid. Rather, as noted in the ANOPR, data centers and other large loads are already "connecting rapidly to the transmission system."[86] To date, the Commission's role in addressing these interconnections has largely been focused on issues arising when large loads co-locate with grid-interconnected generation facilities,[87] and large load interconnections have been moving forward under state tariffs. The ANOPR contemplates a significant – and desirable – shift in responsibility for large load interconnections with the transmission system.

In the past, the Commission has taken care to ensure that major regulatory initiatives of this sort are implemented in ways that account for reliance on the prior regulatory paradigm.[88] For example, when the Commission adopted standardized generator interconnection procedures and

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[84] *Id.* This inefficient pricing is over and above the inefficient pricing resulting from the allocation of interconnection rights on a first-in-time, first-in-right basis rather than through an open season or other mechanism that allocates those rights to their highest and best use, as discussed above in Section II.C.

[85] This subsection relates to the ANOPR's thirteenth principle, that "there must be a plan to implement these proposed reforms . . . , including the treatment of large load interconnections that are already being studied for interconnection." ANOPR at P 30.

[86] ANOPR at P 1 (footnote omitted). *See also, e.g.*, 2024 State of the Markets at 6-7, Docket No. AD06-3-000 (Mar. 20, 2025).

[87] *See, e.g.*, *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,115 (2025) (order to show-cause relating to co-located load arrangements in PJM).

[88] *See, e.g.*, Order No. 888, 61 Fed. Reg. at 21618-19.

agreements, it explicitly grandfathered existing interconnection agreements, making clear that it was "not requiring retroactive changes to individual interconnection agreements filed with the Commission prior to the effective date of this Final Rule."[89] For interconnection requests pending as of the effective date, the Commission expressly provided for the interconnection customer's retention of its queue position and further gave any interconnection customer with a signed interconnection study agreement "the option to either continue with the remaining Interconnection Studies under the Transmission Provider's existing study process or complete the remaining studies for which it does not have a signed Interconnection Study agreement under the provisions of the [procedure prescribed by the] Final Rule . . . ."[90]

NRG urges the Commission to take a similar approach here. Specifically, the Commission should provide for the grandfathering of large load's existing interconnection agreements or other arrangements and ensure that large loads whose interconnections are currently being studied are not disadvantaged by the transition to a set of Commission-prescribed standard procedures. As part of complying with the final rule, transmission providers should be directed to address how they will preserve the actual or implied interconnection queue positions of large loads whose interconnections are already being studied, and large loads should also have the option of completing the process under the existing procedures or under those adopted in compliance with the final rule. Such an approach would not only be consistent with the Commission's past practice but will also advance the ANOPR's intended purpose of "ensur[ing] the timely and orderly interconnection of large loads to the transmission system."[91]

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89 Order No. 2003, 104 FERC ¶ 61,103 at P 911.

90 *Id.* at P 912.

91 ANOPR at P 1 (footnotes omitted).

III. Conclusion

NRG respectfully requests that the Commission take these initial comments into account in its consideration of the ANOPR and its development of a notice of proposed rulemaking in this proceeding.

Respectfully submitted,

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