**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

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| Inquiry Regarding the Commission's Electric Transmission Incentives Policy | ) ) | Docket No. PL19-3-000 |

# COMMENTS OF THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION


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June 26, 2019

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## I. INTRODUCTION

Pursuant to the Notice of Inquiry (NOI) issued by the Federal Energy Regulatory Commission (FERC or Commission) on March 21, 2019,[1] the National Rural Electric Cooperative Association (NRECA) submits its comments on the Commission's inquiries on the scope and implementation of its electric transmission incentives regulations and policies.

NRECA is the national service organization representing the interests of the nation's almost 900 member-owned, not-for-profit rural electric utilities. America's electric cooperatives provide electric service to approximately 42 million people in 47 states. Rural electric cooperatives serve 56 percent of the nation's landmass, 88 percent of all counties, and 12 percent of the nation's electric customers, while accounting for approximately 13 percent of all electric energy sold in the United States. NRECA's member cooperatives include 831 distribution cooperatives and 62 generation and transmission (G&T) cooperatives. Distribution cooperatives provide power directly to their end-of-the-line member-consumers. Nearly 80 percent of the distribution cooperatives are members and owners of the G&T cooperatives, which generate and transmit power to these distribution cooperatives. The remaining distribution cooperatives receive power from other generation sources. Distribution and G&T cooperatives share an obligation to serve their members by providing safe, reliable, and affordable electric service.

NRECA has participated actively in the development of the Commission's electric transmission incentives policies over the years, having filed comments in the rulemaking that led to Order No. 679[2] and in response to the inquiries that led to the Commission's 2012 Incentives

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[1] *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, Notice of Inquiry, 166 FERC ¶ 61,208 (2019).

[2] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057, *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007). *See* Comments of the National Rural Electric Cooperative Association, Docket No. RM06-4-000 (Jan. 11, 2006)

Policy Statement.[3] NRECA has consistently advocated that the Commission, above all, ensure that transmission rates remain just and reasonable and not unduly discriminatory or preferential. This remains the case with regard to electric transmission incentives.

In Section II below, NRECA provides general comments on the NOI in the form of recommended guiding principles for the Commission's incentive policies. NRECA responds to certain of the Commission's specific inquiries in Section III.

## II. GENERAL COMMENTS

### A. The Commission's Incentive Policy Should Implement the Statutory Purposes Outlined in the Federal Power Act, and There Is No Evidence That the Commission Needs To Add New Incentives To Achieve These Purposes.

NRECA commends the Commission for taking the opportunity to reassess whether there is a need to "add to, modify, or eliminate"[4] elements of its electric transmission incentive policies and regulatory requirements. NRECA expects that transmission incentives have cost consumers hundreds of millions of dollars—if not more—since the Commission first implemented Order No. 679. It is therefore critical that the Commission take stock of its policies and ascertain whether they are working. The NOI seeks comments on the potential addition of a number of new incentives, including new return-enhancing incentives, in addition to the Commission's approach to its existing transmission incentives policies. While NRECA appreciates that the questions are just that—questions—they do raise concerns that the Commission is contemplating going down a path of *adding* new incentives without having any concrete sense as to whether its existing incentives are achieving their desired goals. NRECA

(NRECA 2006 Comments); Request for Rehearing of the American Public Power Association and the National Rural Electric Cooperative Association, Docket No. RM06-4-001 (Aug. 21, 2006).

[3] *Promoting Transmission Investment Through Pricing Reform,* 141 FERC ¶ 61,129 (2012) (2012 Incentives Policy Statement). *See* Comments of the National Rural Electric Cooperative Association, Docket No. RM11-26-000 (Sept. 12, 2011) (NRECA 2011 Comments).

[4] NOI at P 13.

urges the Commission to be deliberate in its decision-making process and not to implement new transmission incentives without first evaluating whether existing transmission incentives are accomplishing their intended purpose, as well as developing a record to substantiate the likelihood that any potential new incentives would accomplish their intended purpose.

NRECA fully supports Commission initiatives to encourage investment in transmission where such transmission is beneficial to load-serving entities (LSEs) and the consumers they serve. The Commission's statutory obligation to ensure that transmission rates remain just and reasonable means that any incentives which increase costs to consumers must be no more than necessary to produce demonstrable increased benefits to consumers. NRECA urges the Commission to take a reasonable, fair and balanced approach to incentives. With the NOI, the Commission has a valuable opportunity to step back and examine its incentive policies' objectives.

Order No. 679 was "intended to encourage transmission infrastructure investment"[5] and fulfill the requirements of section 1241 of the Energy Policy Act of 2005,[6] which added section 219 to the Federal Power Act (FPA) and required the Commission to establish by rule incentive-based rate treatments for transmission "for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."[7] Congress directed that the rule:

> (1) promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities; (2) provide

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5 Order No. 679 (summary).

6 Energy Policy Act of 2005, Pub. L. No. 109-58, § 1241, 119 Stat. 594, 961 (2005).

7 16 U.S.C. § 824s(a).

> a return on equity that attracts new investment in transmission facilities (including related transmission technologies); (3) encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and (4) allow recovery of— (A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 824o of this title; and (B) all prudently incurred costs related to transmission infrastructure development pursuant to section 824p of this title.[8]

The Commission's obligation to implement FPA section 219 must be read in conjunction with its obligations not only under FPA sections 205 and 206, but also FPA section 217(b)(4). FPA section 219(d), as the Commission recognized in Order No. 679, "provides that all rates approved under the Rule are subject to the requirements of sections 205 and 206 of the FPA, which require that all rates, charges, terms and conditions be just and reasonable and not unduly discriminatory or preferential."[9] Accordingly:

> [T]he Commission's incentives policy must balance the need for new transmission facilities with its obligation to ensure rates that are just and reasonable and not unduly discriminatory or preferential. That is particularly important for ROE-based incentives. Those incentives—which come directly out of consumers' pockets—must incentivize transmission owners to develop and operate their facilities in a manner that provides consumers with sufficient benefits to justify the extra costs they must pay. Anything short of that is unjust and unreasonable.[10]

Under FPA section 217(b)(4), the Commission must also exercise its authority under the FPA—including section 219—"in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm

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[8] 16 U.S.C. § 824s(b).

[9] Order No. 679 at P 8 (citing 16 U.S.C. §§ 824(d) and 824(e)).

[10] *Consumers Energy Co., et al. v. International Transmission Co., et al.*, 165 FERC ¶ 61,021 (2018) (Commissioner Glick, *dissenting*).

transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs."[11] As the Court of Appeals for the D.C. Circuit has explained, FPA section 217(b)(4) "creates a requirement for the Commission" which would be violated "if the Commission exercised its authority in a manner that was at odds with the needs of load-serving entities."[12]

In light of the statutory provisions in FPA sections 219, 205, 206 and 217(b)(4), the three fundamental questions for the Commission in this inquiry should be:

(i) whether the policies adopted in Order No. 679 and its progeny, and its revisions to those policies with the 2012 Incentives Policy Statement, have in fact benefitted consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion;

(ii) whether these policies have indeed encouraged transmission infrastructure investment in a manner that helps LSEs satisfy their service obligations; and

(iii) whether these policies are resulting in just and reasonable rates that are not unduly preferential or discriminatory.

Unfortunately, NRECA is not aware that the Commission has undertaken any systematic evaluation of its incentives policies since implementing Order No. 679. There is very little information on transmission investment to be gleaned from the many market reports that the Commission and its staff have issued over the past decade, and even less to be learned about the effectiveness of any of the Commission's incentives.

That is not entirely surprising in light of the reporting requirements that the Commission imposed in Order No. 679. There, the Commission adopted an annual reporting requirement, FERC Form 730, for utilities that receive incentive rate treatment for specific transmission

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[11] 16 U.S.C. § 824q(b)(4).

[12] *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 90 (D.C. Cir. 2014).

projects. The annual reporting requirement is minimal; utilities simply report "projections and related information that detail the level of transmission investment."[13] The Commission made clear, however, that "the purpose of the FERC-730 reporting requirement is *not* to provide a quantitative measure of the consumer benefits that result from transmission infrastructure investments."[14] Rather, the Commission stated that it would determine whether a proposed project meets FPA section 219's requirements "[i]n the proceeding approving incentives and recovery of the costs of incentives in rates….and thereby provide consumer benefits and also set metrics to ensure those benefits are justified on an ongoing basis."[15] To the extent that the Commission has, in fact, set metrics in individual cases to ensure that consumer benefits are justified on an ongoing basis, NRECA is unaware of such analyses, and hopes that the Commission would include such analyses in any proposed rulemaking addressing new incentives.

NRECA is aware that the Commission staff has issued two reports on transmission metrics: a preliminary report in March 2016, and a follow-up report in October 2017.[16] The 2016 Transmission Metrics Report mentions Order No. 679 only in passing,[17] and the 2017 Transmission Metrics Report does not mention it or the Commission's transmission incentives policies at all. Rather, these reports focus on the Commission's Order No. 1000[18] reforms and

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13 Order No. 679-A at P 117.

14 *Id*. at P 119 (emphasis added).

15 *Id*.

16 *Transmission Metrics: Initial Results*, Staff Report, Federal Energy Regulatory Commission, Docket No. AD15-12-000 (March 2016) (2016 Transmission Metrics Report); *2017 Transmission Metrics*, Staff Report, Federal Energy Regulatory Commission (Oct. 2017) (2017 Transmission Metrics Report).

17 2016 Transmission Metrics Report at 5.

18 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and*

the level of transmission investment that has been undertaken in light of those reforms.[19] The reports provide no insight into whether the Commission's incentive policies have resulted in construction of transmission that would not otherwise have been built or achieved the objectives set forth in FPA sections 219 and 217(b)(4). In fact, the reports provide little insight even into the question of whether the level of transmission investment has been sufficient. Indeed, staff acknowledged that "it is difficult to assess whether the electric industry is investing in sufficient transmission infrastructure to meet the nation's needs and whether the investments made are more efficient or cost-effective."[20]

NRECA has scoured the Commission's website and staff reports and has not found any compilation of information from Form 730 or any analysis attempting to evaluate whether the incentives that have been granted have resulted in the construction of transmission that is benefitting LSEs and consumers, in accordance with the objectives laid out in the Commission's

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*clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (Order No. 1000).

[19] Both reports focused on metrics falling "into three broad categories: (1) metrics designed to evaluate key goals of Order No. 1000; (2) metrics designed to indicate whether appropriate levels of transmission infrastructure exist in a particular region; and (3) metrics designed to permit analysis of the impact of Commission policy changes by comparing key values before and after changes take place." 2017 Metrics Report at 6. The 2017 report also discussed "three additional metrics: (1) number of unique developers submitting proposals; (2) number and percentage of selected nonincumbent proposals; and (3) stakeholder participation in regional transmission planning processes." *Id*. at 6-7. The purpose of these new metrics is to "help the Commission to evaluate progress in achieving the key goals of Order No. 1000." *Id*. at 7.

[20] *Id*. at 6. To the extent that the level of transmission investment is useful in evaluating the Commission's need for new categories of incentives or new incentives policies, NRECA notes that there does not seem to be any lack of transmission investment. According to a recent United States Department of Energy report, transmission investment by investor-owned utilities increased steadily from $10.2 billion in 2010 to 20.1 billion in 2015. United States Department of Energy Annual U.S. Transmission Data Review (Mar. 2018) at 11, available at https://www.energy.gov/sites/prod/files/2018/03/f49/2018%20Transmission%20Data%20Review%20FINAL.pdf. (Figure 2-9, Historical and projected transmission investment by shareholder-owned utilities, citing EEI 2016 data). A Brattle Group report similarly shows that the total U.S. annual transmission investments between 2013 and 2017 (excluding ERCOT) was $90.5 billion. The Brattle Group, *Transmission Solutions: Potential Cost Savings Offered by Competitive Planning Processes*, Discussion Paper Presented to NARUC (Nov. 13, 2018), at 11, available at http://files.brattle.com/files/14880_brattle_competitive_transmission_naruc_11-13-18.pdf.

incentives policies.[21] Given this dearth of information, along with the Commission staff's acknowledged difficulty in evaluating whether even the overall level of transmission investment itself has been sufficient, the Commission would be putting the cart before the horse if it were to implement new transmission incentives at this time, particularly return-enhancing incentives that increase the costs borne by consumers. Before diving into any major policy changes or adopting new and potentially costly incentives, the Commission should make a systematic effort to gather empirical data to determine whether incentives that have been granted have accomplished what they set out to do. The unexamined questions include:

- Where incentives have been granted, were facilities built/are facilities being built that are helping to ensure reliability and/or reduce the cost of delivered power by reducing transmission congestion?

- Is additional transmission being built by transmission owners who have received various risk-reducing incentives?

- Is additional transmission investment taking place where return-enhancing incentives have been granted?

- If so, is this transmission investment helping LSEs better serve their native loads in a cost effective manner?

- Where incentives have not been granted, whether because they were not requested or because they were denied, are facilities still nonetheless being built that are helping to ensure reliability and/or reduce the cost of delivered power by reducing transmission congestion?

Without at least making an effort to answer these very basic questions, the Commission is fumbling around in the dark in making decisions that could cost consumers hundreds of millions

[21] In addition to the two transmission metrics reports, the Commission's Office of Energy Projects has also issued Energy Infrastructure Updates that provide cursory information on completed (and proposed) transmission projects by line length miles. It is impossible to draw any conclusions from these cursory updates; among other things, there is no delineation of transmission projects constructed that received incentives versus those that did not.

of dollars. The Commission has an obligation to try to obtain answers to these questions before implementing new incentives.

### B. The Commission Should Ensure That Non-Jurisdictional Utilities Have Comparable Opportunities To Obtain Incentives and Should Encourage Public Power Participation in Transmission Projects.

Within the limits of its rate jurisdiction, the Commission should adopt incentive policies that provide non-jurisdictional transmission-owning utilities, including rural electric cooperatives and public power agencies, transmission incentives comparable to those afforded to public utility transmission owners. Non-jurisdictional transmission-owning cooperatives should not be placed at a competitive disadvantage, and the burden for them to apply for incentives should not be more onerous than for transmission-owning public utilities. Cooperatives should continue to be eligible for the same incentives that are available to investor-owned utilities, Transcos and others.

Additionally, the Commission should encourage cooperative and public power participation in new transmission investment. In this regard, the Commission should rethink its decision in Order Nos. 679 and 679-A to not require that applicants for incentives demonstrate that they have offered the opportunity to participate in the project to non-jurisdictional transmission owners. The Commission justified that decision by stating that it "cannot compel investment or <u>certain</u> types of investment."[22] The Commission can, however, set the conditions under which it will grant transmission incentives to public utility transmission owner applicants. To be clear, NRECA does not believe there should be a separate return-enhancing incentive adder to encourage joint ownership; such an adder would simply add costs, thus taking away from customers some of the benefits to be obtained through participation by non-jurisdictional

[22] Order No. 679-A at P 102 (emphasis in original).

entities. But the Commission can and should encourage investment in, and joint ownership of, transmission facilities by non-jurisdictional entities. Given the relative financial strength of non-jurisdictional transmission owners, their access to relatively low-cost capital, and their focus on projects that benefit retail customers, the Commission should require applicants for transmission incentives to explain the efforts they have made to encourage participation by non-jurisdictional entities. Such information is relevant to the Commission's decision whether to grant an application for incentive rate treatment, because non-jurisdictional utilities' access to low-cost capital could alleviate the need for certain incentives while helping to ensure that needed facilities get built. Moreover, taking concrete steps to encourage such participation would comport with the requirement of FPA section 217(d)(4) that the Commission "shall exercise its authority under the [FPA] in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities…"

NRECA notes that there have been a number of successful collaborations between jurisdictional and non-jurisdictional transmission owners to build critical transmission projects. For instance, the first project subjected to competitive bidding by the Midcontinent Independent System Operator (MISO) was the Duff-Coleman project, awarded by MISO to Republic Transmission, LLC, with Hoosier Energy Rural Electric Cooperative, Inc., a non-public utility transmission-owning member of MISO, entitled to ownership of between 10% and 20% of the project. Likewise, CapX2020 is a joint initiative of eight non-jurisdictional utilities, including three G&T cooperatives, and three public utilities in Minnesota, North Dakota, South Dakota, and Wisconsin, that was formed to upgrade and expand transmission. To date, the initiative has added 800 miles of line in four 345-kilovolt and a 230-kilovolt project, investing $2 billon. FERC should encourage more such cooperation.

### C. <u>New ROE Adders Should Be Used Sparingly, with Risk-Reducing Incentives as a Preferred Approach.</u>

The Commission has classified transmission incentives into two broad categories: risk-reducing incentives (*i.e.*, non-ROE incentives) and return-enhancing incentives (*i.e.*, ROE adder incentives). The Commission also provides for a hypothetical capital structure as an incentive and classifies this as a non-ROE incentive,[23] although depending on the utility and the capital structure selected, it can increase the utility's return.[24] Risk-reducing incentives include, among other things, the ability to:

- Receive current recovery of reasonable pre-certification expenses;
- Recover up to 100% of prudently incurred abandoned plant costs;
- Recover up to 100% of construction-work-in progress (CWIP) in rate base; and
- Use securitization or other financing practices that can attract transmission investors interested in stable returns.

The purpose of a risk-reducing incentive is to shift risks directly to transmission customers. A prime example is when the Commission allows the transmission owner to recover (subject to a section 205 filing) prudently incurred expenses made in a project that was canceled due to reasons outside the control of the transmission owner. The transmission developer in that case is not enriched financially by the abandonment incentive, but the financial risk is shifted to

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23 NOI at P 41.

24 For transmission-owning public utilities, hypothetical capital structures often provide higher returns. But for some utilities, particularly non-jurisdictional utilities, hypothetical capital structures can be an important risk-reducing incentive. For smaller non-jurisdictional utilities, a transmission project—even a minority stake in a large project—can approach or exceed its other transmission or distribution investment.

customers. The purpose of a return-enhancing incentive, by contrast, is to compensate (financially) the project developer where a project has unusually high levels of risk.

The Commission's inquiries throughout the NOI regarding possible new approaches to its incentive policies and specific new potential incentive objectives seem to be focused mostly on adopting new return-enhancing incentives. As an initial matter, in light of the Commission's concurrent inquiry in Docket No. PL19-4-000[25] into its method for determining the base ROE, including how the zone of reasonableness will be developed (and thus, what the cap on the ROE with incentive adders can be), any changes to incentive ROE policies—and in particular any new return-enhancing incentives—must be coordinated with changes to base ROE policies. The Commission's ROE NOI could well result in new approaches to establishing the zone of reasonableness, possibly including non-market based criteria. It is essential that rates paid by customers continue to be just and reasonable and reflective of the market price of the capital utilities need to develop transmission projects, especially given that transmission remains, for the most part, a monopoly service.[26]

More generally, risk-reducing incentives should be favored over return-enhancing incentives, because the benefits of the former are more narrowly tailored to the potential risks of investment and therefore are more likely to achieve the desired outcome. Absent compelling circumstances, there is no rational basis for giving a developer return-enhancing incentives to compensate for risk that is already mitigated by risk-reducing incentives. If a transmission

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[25] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, Notice of Inquiry, 166 FERC ¶ 61,207 (2019) (ROE NOI).

[26] The Commission should also be circumspect about implementing new types of return-enhancing incentives given that transmission owners are generally receiving significantly higher base returns on equity from the Commission than from state commissions. *See, e.g.*, *Coakley v. Bangor-Hydro Elec. Co.*, 150 FERC ¶ 61,165, at P 85 (2015), Opinion No. 531-B (acknowledging that 10.57% ROE awarded by FERC exceeded 89% of state commission-awarded ROEs).

owner is, for example, able to recover CWIP in rate base prior to a project's going into service, and/or is guaranteed recovery of the costs of investment in the event the project is canceled, much of that project's risk is mitigated. Additional incentive adders should be the exception rather than the rule and, as a general matter, should be available only in circumstances where the economic risks of the project still make it unlikely for the developer to proceed successfully even with risk-reducing incentives (and assuming, of course, that there is demonstrated benefit to consumers of the project). A transmission owner should have a high burden to demonstrate a need for a higher return for a project on the basis that it is "more risky" once that alleged increased risk has been mitigated by shifting the risk to customers. Return-enhancing incentives should only be available for projects with high risks that cannot otherwise be adequately mitigated by risk-reducing incentives. The goal should be to lower risk for investors rather than simply to increase returns.

Another fact the Commission should consider in evaluating whether the risks of a particular transmission project merit return-enhancing incentives is that most transmission owners now have formula rates, which is a substantial risk-reducing benefit to transmission owners and investors, as Wall Street and transmission owners themselves have acknowledged.[27] As the Commission recognized in Order No. 679, "formula rates can provide the certainty of recovery that is conducive to large transmission expansion programs. Moreover, formula rates alleviate the need for other relief sought by commenters. For example, public utilities with formula rates will generally be able to flow through increased transmission investment without concern as to the Commission's five-month suspension."[28] Unless a cost is demonstrated to be

[27] *See, e.g.*, Docket No. EL15-45 Transcript at 264 and 265:19-24 (testimony of Adrien McKenzie).

[28] Order No. 679 at P 386.

imprudently incurred—a very difficult burden for challengers to meet—the transmission owner has certainty of recovery of such costs. And certainty of cost recovery is a preferred means to induce transmission investment than higher returns.

## D. The Risks/Challenges Approach from the 2012 Incentives Policy Statement Should Be Retained.

### 1. Incentives Should Be Limited to Those Necessary To Encourage the Desired Behavior.

Incentives should be designed to facilitate construction of transmission projects that will reduce congestion, enhance reliability and otherwise benefit consumers—and which otherwise might not be able to be constructed due to high risks. The Commission is also obligated to ensure that transmission rates remain just and reasonable. NRECA believes that to accomplish these objectives, the Commission should retain the risks/challenges approach adopted in the 2012 Incentives Policy Statement. In considering potential approaches to incentives, certain guiding principles should apply.

Incentives should not be available for any projects that transmission providers are already obligated to build. In other words, if a project does not face unusually high risks or financing challenges, transmission incentives should not be granted to do what the transmission owner is legally required to do. This would include, for example, constructing new transmission lines (if needed) to serve the transmission owner's native load. NRECA has heard from some of its members that they have faced difficulty in certain regions in obtaining transmission service that is as reliable as that provided to the transmission owners' own retail customers. The Commission's long-standing comparability requirements under the open access regime require that public utility transmission owners serve their non-retail native load customers on the same basis as their own retail loads, and incentives should not be provided to comply with this requirement. Cooperatives and other wholesale customers should not have to pay incentive rates for the construction of transmission facilities necessary for them to receive transmission service comparable to that the transmission owner provides to itself. That would violate the notion of comparability of service under Order No. 888[29] and contravene the Commission's obligations under FPA section 217(b)(4). Along these same lines, as discussed below in Section II.D, unless a transmission owner faces demonstrated risks and challenges to upgrading an existing line, the upgrade should generally be considered part and parcel of its obligation to provide open access transmission service.

Similarly, transmission incentives should not be made available to comply with mandatory NERC reliability standards. The Commission cannot ensure that rates remain just and reasonable if it were to provide incentive adders—above the cost-of-service—to projects that transmission providers are already under a legal obligation to construct.

Finally, the Commission should be mindful of the timing of transmission incentives. Incentives that reduce risk may be appropriate *before* a project is constructed to facilitate that project going into service, but return-enhancing incentives that continue on indefinitely are no longer incentivizing behavior. Accordingly, the Commission should consider placing time limits on incentives, *i.e.*, some form of sunset provisions.

### 2. Retaining the Risk-Reduction/Challenges Approach from the 2012 Incentives Policy Statement Obviates the Need for New Incentives to Address Various Objectives.

The Commission asks a series of questions about whether it should consider implementing new incentives (presumably return-enhancing incentives) to meet twelve different

[29] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*; *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

types of objectives.[30] NRECA believes that incentives should not be provided based solely on the category of projects. Rather, the Commission can and should address the different objectives it seeks to achieve under the existing framework. Thus, for example, there is no need for a special incentive for "advanced technology." Advanced technologies will be developed when there are good business reasons to do so and when their deployment is cost effective. Incentives for use of new technologies should be available on a case-by case basis where they are needed to overcome risks and challenges associated with development of a new beneficial transmission project. As the Commission noted in the Notice of Proposed Rulemaking that led to Order No. 679, the risk-reducing and, where necessary, return-enhancing incentives offered to facilitate construction of beneficial transmission projects "will stimulate investment in new transmission facilities, which will, in turn, provide opportunities for the deployment of innovative technologies for those new transmission facilities."[31]

Similarly, there should be no special incentive for Order No. 1000 projects or for interregional projects. The key to facilitating additional interregional transmission is resolving cost allocation issues, not offering additional incentives. The Commission should not favor certain projects over others as those decisions should be handled during each region's respective planning process.

### E. <u>Incentives Should Not Be Granted Automatically Without Review</u>

Throughout the NOI, the Commission seeks input on whether certain types of incentives should be granted automatically.[32] The Commission currently ensures that granting incentives

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30 Section II.B of the NOI at PP 19-35.

31 *Promoting Transmission Investment Through Pricing Reform*, Notice of Proposed Rulemaking, 113 FERC ¶ 61,182 at P 65 (2005).

32 In addition to Questions 90 – 92, which address this topic globally, Question 7 asks if transmission projects "with a demonstrated likelihood of benefits" should be awarded incentives automatically. Question 16 asks

will result in just and reasonable rates by considering the applicability of those incentives on a case-by-case basis. There has been no showing that the practice of deciding, on a case-by-case basis, whether a given incentive should be granted to a public utility or a particular project is inefficient or not working. Unless and until that demonstration has been made, pre-approval of incentives is not warranted.[33]

NRECA submits that pre-approving any type of incentives would inappropriately relieve the Commission of its statutory obligation to ensure that the total package of incentives, on top of the base ROE, will result in just and reasonable rates, terms, and conditions of service.[34] Pre-approving certain incentives and thereby automatically deeming them to be appropriate shifts the discussion's starting point from whether the applicant has supported all elements of its proposed rates, terms, and conditions of service in favor of transmission developers, and inappropriately places the burden on other parties to file FPA section 206 complaints against automatically-granted incentives that may be unnecessary. As the Commission explained in Order No. 679, to comport with FPA section 219, the purpose of the Commission's incentive policy must be to "benefit consumers by providing real incentives to encourage new infrastructure, not simply

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whether transmission projects with certain characteristics should be awarded transmission incentives automatically. Questions 52 and 53 ask whether risk reducing incentives (100% CWIP in rate base, abandoned plant recovery, and regulatory asset treatment), and/or possibly others, should be granted automatically for transmission projects selected in a regional transmission plan for purposes of cost allocation. Question 62 again asks whether certain incentives such as the provision of CWIP in rate base or the guaranteed abandoned plant recovery should be provided automatically to RTO members. Question 70 asks again if regulatory asset treatment and CWIP should be granted automatically to certain types of transmission projects. And Question 77 asks if the Commission should grant the abandoned plant incentive automatically, and when doing so might be appropriate.

[33] *See Competitive Transmission Development Technical Conference*, Post-Technical Conference Comments of the American Public Power Association and the National Rural Electric Cooperative Association, Docket No. AD16-18-000 (Oct. 3, 2016).

[34] 16 U.S.C. § 824d(e).

increasing rates in a manner that has no correlation to encouraging new investment."[35] In order to ensure that result, "the Commission will continue to require applicants seeking incentives to demonstrate how the total package of incentives requested is tailored to address demonstrable risks and challenges."[36] If the Commission were to grant any type of incentives automatically, it would seriously undermine this commitment.

On a related note, the Commission should consider adopting policies for revoking incentive rate treatments where required performance does not occur or expected benefits are not obtained, *e.g.*, a once-independent Transco becomes affiliated with a wholesale market participant (*see* Question 58 below), or a utility cancels a project for reasons under its control. Any revocation should likewise be implemented on a case-by-case basis, but it would be useful in any proposed rulemaking for the Commission to propose guidelines on how interested parties could raise this issue to the Commission and on any performance metrics which could be used in evaluating whether such a revocation would be appropriate.

### F. Participation in Open, Regional Transmission Planning Should Be a Condition for Incentive Rate Treatment.

Order No. 679 created a rebuttable presumption that a project for which incentive rate treatment is sought meets the criteria for ensuring reliability or reducing the cost of delivered power by reducing transmission congestion if the project either (1) results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion, and is found acceptable to the Commission, or (2) has received construction approval from an appropriate state commission or state siting authority.[37] The Commission has clarified that to the

[35] *Id*.

[36] 2012 Incentives Policy Statement at P 10.

[37] Order No. 679 at P 41.

extent such processes do not meet these criteria, the applicant bears the burden to demonstrate that its project meets the reliability/congestion criteria.[38] The Commission has conditioned incentive awards in certain cases on the approval of the project in a regional planning process.[39] With the adoption of the regional planning requirement in Order No. 890,[40] on first blush it would seem this condition is no longer needed. However, NRECA is concerned that there could be more localized transmission projects that fall outside the scope of the open, transparent regional planning process.

The Commission should reaffirm its commitment to requiring incentive applicants to demonstrate that the projects for which they seek incentives have gone through a planning process that complies with the Order No. 890 standards—even if such projects are designated as local in nature. So long as local projects are indeed the product of a coordinated, open and transparent planning process, they could be eligible for incentives. Such a condition would promote customer participation and help to increase the likelihood that the project will, in fact, result in ratepayer benefits, consistent with the requirements of FPA section 219 and Order No. 679.

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[38] *Southern Cal. Edison Co.*, 123 FERC ¶ 61,293, at P 21 (2008) (citing Order No. 679-A at P 49).

[39] *See, e.g., Green Energy Express LLC*, 129 FERC ¶ 61,165 (2009), *reh'g denied*, 130 FERC ¶ 61,117 (2010).

[40] *See* Order No. 890 at PP 437 - 551.

## III. ANSWERS TO SPECIFIC QUESTIONS

### A. Approach to Incentive Policy

#### 1. Incentives Based on Project Risks and Challenges

***Q 1) Should the Commission retain the risks and challenges framework for evaluating incentive applications?***

As discussed above in Section II.D, NRECA believes that the risks and challenges of a particular transmission project should remain the focal point for evaluating incentives requested pursuant to FPA section 219. Retaining the risks and challenges framework is the best way to ensure that incentives are narrowly tailored to facilitate development of transmission projects that are needed to provide consumer benefits, but that otherwise would not be constructed due to significant financial or other risks.

***Q 2) Is providing incentives to address risks and challenges an appropriate proxy for the expected benefits brought by transmission and identified in section 219 (i.e., ensuring reliability or reducing the cost of delivered power by reducing transmission congestion)? If risks and challenges are not a useful proxy for benefits, is it an appropriate approach for other reasons?***

Providing incentives to address risks and challenges is not necessarily a direct proxy for the expected benefits brought by transmission and identified in FPA section 219. However, NRECA believes that this is still the most appropriate approach to incentives because it serves to ensure that incentives are available to projects that would not otherwise be developed due to risks or challenges that cannot be mitigated, either through risk-reducing incentives or other means. This does not mean that the benefits of a transmission project should be ignored. However, the open and inclusive transmission planning processes required by Order No. 890[41] is the appropriate place to determine whether a particular project is worth pursuing because it will

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

provide benefits to ratepayers. If the transmission owner or sponsor of the project believes that it will be difficult to pursue because of risks and challenges, then it should be eligible to apply for incentives (with the caveat that as explained above in Section II.C, risk-reducing incentives should be considered before resorting to return-enhancing incentives).

***Q 3) The Commission currently considers risks both in calculating a public utility's base ROE and in assessing the availability and level of any ROE adder for risks and challenges. Is this approach still appropriate? If so, which risks are relevant to each inquiry, and, if they differ, how should the Commission distinguish between risks and challenges examined in each inquiry?***

The risks that the Commission considers in calculating a public utility's base ROE and in assessing the availability and level of any ROE adder for risks and challenges are distinct, but must also be considered together. Base ROE should account for the transmission owner's risk, and regardless of the specific method(s) the Commission ultimately decides to be appropriate for determining base ROE, industry-wide risk profiles should be used when determining the appropriate ROE needed to attract capital. How to decide the composition of an appropriate proxy group for this purpose should be addressed in the ROE NOI in Docket No. PL19-4-000.

The Commission's inquiry in the instant docket should address incentives that are project specific—that is, those that are needed to overcome specific risks and challenges in order for transmission owners to develop beneficial projects that may otherwise not be developed.

### 2. Incentives Based on Expected Project Benefits

***Q 4) Would directly examining a transmission project's expected benefits improve the Commission's transmission incentives policy, consistent with the goals of section 219? Are there drawbacks to this approach, particularly relative to the current risks and challenges framework?***

FERC should not cause customers to incur increased costs in the form of return-enhancing incentives unless: (1) incentives are needed to bring the project to fruition; (2) other measures will not suffice; and (3) the expenditures will result in concomitant benefits for consumers. A drawback to an approach that focuses on the project's benefits is that any transmission project—even ones that are routine and would end up getting built without incentives—can be shown to have some "benefit." A better approach is to stick with the risks and challenges approach.

If FERC does focus on a project's benefits, it needs to (i) consider developing a clearly defined, transparent, defensible cost-benefit test and (ii) address what happens when actual costs end up being more than projected costs, as is often the case. NRECA recognizes that developing cost-benefit tests is a difficult task and that there are multiple theories regarding how to analyze both costs and benefits. Another drawback to examining a transmission project's expected benefits is that these benefits are projected from a single model run at a single point in time. Basing incentives off this one data point could lead to undeserved incentives and excessive costs. For these reasons, NRECA does not believe this approach to incentives is a productive one.

In any event, NRECA does not believe that granting incentives based on expected project benefits would facilitate development of projects that would not have been developed otherwise. Thus, incentives granted based on expected benefits could end up being simply a windfall on top of the base ROE earned by the owner of a transmission project.

***Q 5) If the Commission adopts a benefits approach, should it lay out general principles and/or bright line criteria for evaluating the potential benefits of a proposed transmission project? If so, how should the Commission establish the principles or criteria?***

Any criteria developed should have input from LSEs who pay the costs. FPA Section 217(b)(4) directs the Commission to ensure the transmission grid is planned and expanded to meet LSE long-term needs. That obligation applies when the Commission exercises its authority under FPA section 219.

***Q 7) Should transmission projects with a demonstrated likelihood of benefits be awarded incentives automatically? How could the Commission administer such an approach?***

No. As discussed in Section II.E, above, there should be no automatic provision of incentives.

If the Commission were to take the approach of a "demonstrated likelihood of benefits," at the very least it should give intervenors the opportunity to contest whether the project will indeed provide benefits and that the costs won't outweigh the benefits. How can the Commission determine that the resulting rate is just and reasonable if incentives are provided automatically? Even a rebuttable presumption would be too heavily weighted in favor of granting incentives. Also, the transmission owner should have to show that the benefits would not occur without the incentives; if there were no benefits at all, the transmission would not be built. Thus, projects should qualify for incentives only if the incentives are necessary for the project to be constructed, and the project will deliver benefits to consumers in excess of cost.

***Q 8) If the Commission grants incentives based on expected benefits, should the level of the incentive vary based on the level of the expected benefits relative to transmission project costs? If so, how should the Commission determine how to vary incentives based on the size of benefits?***

The Commission should not vary incentives based on size of benefits without also considering the associated costs of a project. Expected benefits matter in terms of their relationship to expected costs; both must be measured to ensure that ratepayers will receive benefits from a specific project that are at least equal to the expected costs, including the added cost of the incentives. Instead, the Commission should ensure that incentives are truly needed to address the front-end risks of project development.

***Q 9) Should incentives be conditioned upon meeting benefit-to-cost benchmarks, such as a benefit-cost ratio? If so, what benefit-to-cost ratios should be used?***

While NRECA sees the potential value in having such a requirement, NRECA recognizes it could be unwieldy to implement. To the extent the Commission does pursue such an approach, it is critical that the development of any such benchmarks have input not just from the transmission owners but from LSEs as well, and any such benchmarks must be transparent. Although NRECA does not recommend any specific benefit-to-cost ratio at this time, it urges the Commission to ensure that any ratio result in benefits outweighing the costs.[42]

NRECA believes, however, that use of benefit-to-cost benchmarks is more appropriate in determining whether a project should be included in an RTO's (or the relevant transmission owner's) planning process in the first instance. (And this is a complex, highly technical and often disputed process.) In its simplest terms, if a project's costs are going to outweigh its benefits, the regional planning process' procedures would likely not approve its moving forward. Therefore, the fact that a project *meets* certain benefit-to-cost benchmarks, should not be used as justification for granting incentive adders.

***Q 10) Should incentives be based only on benefit-to-cost estimates or should the Commission condition the incentives on evidence that those benefit-to-cost estimates were realized?***

If the Commission were to base eligibility for incentives on a cost-to-benefit estimate, it should consider the possibility of allowing interested parties to seek termination of the incentives if there is evidence that the benefit-to-cost estimates are not, or are no longer, being realized.

[42] To put this in perspective, MISO reported on the results of one of its competitive selection processes: the recent "Duff-Coleman EHV 345 kV Competitive Transmission Project had a weighted benefit to cost ratio of 16.1 to 1, which far exceeds the 1.25 to 1 benefit to cost ratio required for designation of a 345 kV transmission project as a Market Efficiency Project." Selection Report, Duff-Coleman EHV 345 kV Competitive Transmission Project, MISO (Dec. 20, 2016), at 12, available at https://cdn.misoenergy.org/Duff-Coleman%20EHV%20345kv%20Selection%20Report82339.pdf.

(However, it may not be appropriate to require refund of incentives already granted.) Otherwise, there could be major cost overruns, which—on top of incentives—would cost consumers much more than the benefits derived. As noted above, however, NRECA believes that this approach is unwieldy. Among other things, any projection of benefits, at any point in the future, is simply a snapshot in time and can change over the lifetime of a project. Accordingly, NRECA recommends that the Commission not adopt such an approach for incentives.

***Q 11) If an incentive is conditioned upon a transmission developer meeting benefit-to-cost benchmarks, what types of benefits and costs should a transmission developer include, and the Commission consider to support requests for such incentives? Should there be measurement and verification, and if so, over what time period? If expected benefits do not accrue, should the incentive be revoked?***

If the expected benefits do not accrue, the incentive should be revoked. (And if the incentive takes the form of an adder, it should not continue indefinitely even if the benefits do accrue.)

### 3. Incentives Based on Project Characteristics

***Q 12) How, if at all, would examining transmission projects' characteristics in evaluations of transmission incentives applications improve the Commission's transmission incentives policy and achieve the goals of section 219? Are there drawbacks to this approach, particularly relative to the current risks and challenges framework? Would this approach result in different outcomes, as compared to the current risks and challenges approach for granting incentives?***

To the extent the Commission is referring to ROE adders, there are significant drawbacks. They would raise costs to consumers. In the absence of risks/challenges, it seems likely a project could move forward without incentives. Simply put, if a project does not present unusual risks and challenges, there is no reason for providing an incentive.

Additionally, granting incentives based on project characteristics is problematic because the characteristics that the Commission wants to encourage may change over time. Unless incentives are granted for a limited duration, ratepayers may pay additional costs for projects with characteristics that are no longer desired. NRECA urges the Commission to continue its policy of granting incentives that address concrete and quantifiable development risks that could endanger a beneficial project from meeting commercial operation.

***Q 16) Should transmission projects with certain characteristics be awarded incentives automatically? How could the Commission administer such an approach?***

See the answer to Question 7, above, and Section II.E. If the Commission were to take the approach that incentives based on certain characteristics are automatically granted, at what stage would an intervenor have to weigh in and object? How can the Commission determine that the resulting rate is just and reasonable if incentive provided automatically?

## B. Incentive Objectives

### 1. Reliability Benefits

***Q 17) Should the Commission tailor incentives to promote these types of projects based on their expected reliability benefits? If so, how should the Commission differentiate these projects from others required to meet reliability standards?***

The latter is a good question. Utilities are required to meet reliability standards anyway, and FERC's discussion of "enhanced" reliability is vague and undefined. Given that transmission remains, for the most part, a monopoly service, NRECA would generally not favor requiring customers to fund transmission owner expenditures in excess of legal requirements.

NRECA notes that some of its members located in very remote rural areas are not currently receiving reliable service. The Commission should not require customers to pay incentive rates merely to receive barely acceptable service. *See* Section II.D.1, above.

***Q 18) Are there specific reliability benefits or project characteristics that could merit such an approach?***

***Q 20) Should the Commission incentivize transmission facilities that expand access to essential reliability services, such as frequency support, ramping capability, and voltage support?***

Incentives should not be provided for providing access to essential services, unless the project itself presents unusual risks and/or challenges. In any event, most transmission projects will provide some access to these services, meaning that incentives for providing access to such services will invite a large amount of free riding.

### 2. Economic Efficiency Benefits

***Q 22) Should the Commission tailor incentives to promote projects that accomplish the outcomes of reducing congestion or facilitating access to additional generation?***

Reduction of congestion and facilitation of access to additional generation are the focus of RTO and ISO planning processes, and projects not designed to accomplish either of these objectives (or to enhance reliability) will not be approved in those processes. Incentives should be reserved for beneficial projects that present unusual risks and challenges.

### 3. Persistent Geographic Needs

***Q 26) Should the Commission utilize an incentives approach that is based on targeting certain geographic areas where transmission projects would enhance reliability and/or have particular economic efficiency benefits? If so, how should the relevant geographic areas be identified and defined? What entity (e.g., the Commission, RTOs/ISOs, state regulators, other stakeholders) should designate such areas?***

***Q 27) What criteria should be used to define such geographic areas? Procedurally, how should such geographic areas be determined, monitored, and updated?***

The criteria to define such geographic areas must be developed with input from not just the transmission owners but the LSEs they serve as well. The Commission should be wary of bright-line metrics, as they can disadvantage transmission-dependent rural electric cooperatives, especially when customer counts or customer per mile statistics are considered.

### 4. Security

***Q 32) Should the Commission incentivize physical and cyber-security enhancements at transmission facilities? If so, what types of security investments should qualify for transmission incentives? What type of incentive(s) would be appropriate?***

Physical and cyber-security requirements are set forth in NERC Reliability Standards approved by this Commission. There is no justification for providing an incentive to transmission owners to comply with such standards, as compliance is required by statute.[43] *See* Section II.D.1, above. Nor is there any real risk of prudent expenditures to achieve such compliance not being accepted for recovery by the Commission.

### 5. Resilience

***Q 34) Should transmission projects that enhance resilience be eligible for incentives based upon their reliability-enhancing attributes?***

This is another area where transmission owners should not need "incentives" to shore up their facilities so that they can "withstand and reduce the magnitude and/or duration of disruptive events…" [44] Moreover, the record of U.S. transmission providers in maintaining continuous service is quite good, so there does not appear to be a need for incentives in this regard.

### 6. Improving Existing Transmission Facilities

***Q 38) Can the Commission distinguish between incremental improvements that merit an incentive and those maintenance-related expenses that a transmission owner would make in its ordinary course of business?***

It would be very difficult to be able to do so. As NRECA indicated in its 2006 comments,[45] incentives should be limited to new investment, including upgrades, and new behavior. Incentives should not be granted for existing investment.

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43 FPA section 215(b).

44 NOI at P 28.

45 NRECA 2006 Comments, *supra* n. 2, at 9.

***Q 39) How should a transmission owner seeking this type of incentive demonstrate increases or improvements in the capabilities or operations of existing transmission facilities?***

Incentives should not be granted simply for demonstrating a project will increase or improve the capabilities or operations of existing transmission facilities. All human endeavors can be improved. Incentives should be available only on a showing that the particular increase or improvement proposed responds to a genuine consumer need, and that it would not happen without incentives.

***Q 40) Should the Commission provide a stand-alone, transmission technology-related incentive? If the Commission provides a stand-alone transmission technology-related incentive, what criteria should be employed for a technology to be considered as meriting an incentive? Should the Commission periodically revisit the definition of an eligible technology?***

NRECA does not see a need for such a stand-alone incentive. If there are particular risks associated with implementing a particular technology, and it merits pursuing, this can be addressed on a case-by-case basis.

***Q 43) Should the Commission interpret section 219(b)(3) to encourage improvements that are not historically considered part of the transmission system, such as, for example, software upgrades, technologies that allow for faster ramping, or other innovative measures that achieve the same goals as new transmission facilities? What types of incentives could increase the adoption of these technologies? Are there forms of performance-based ratemaking with respect to transmission that the Commission should explore? If so, describe such alternative ratemaking structures.***

Regarding these types of investments, unless there is a clearly articulated need that is going on unmet or a clearly defined benefit to customers, it is unclear why there would be any incentives. Additionally, performance-based ratemaking is a dangerous path to go down with transmission, which is still a monopoly service.

### 7. Interregional Transmission Projects

***Q 44) Should the Commission use incentives to encourage the development of interregional transmission projects? How, if at all, would any such incentive interact with Order No. 1000's reforms?***

No. The issue is not sufficient incentives but rather addressing and adopting appropriate cost allocation. Reforms are still underway in some regions to comply with Order No. 1000's requirements and promote the development of interregional transmission projects, such as the pending filing at the Commission involving the Coordinated System Plan between MISO and SPP.[46]

### 8. Unlocking Locationally Constrained Resources

***Q 47) Should the Commission use incentives to encourage the development of transmission projects that will facilitate the interconnection of large amounts of resources?***

The Commission should wait to see if its Order No. 845[47] reforms alleviate the interconnection queuing problems. Additionally, given that the Commission's regulations require RTOs and ISOs to consider whether proposed transmission projects are needed to facilitate compliance with state public policy goals,[48] it is not clear why further incentives for such projects are needed.

### 9. Ownership by Non-Public Utilities

***Q 51) Should the Commission consider granting incentives to promote joint ownership arrangements with non-public utilities and, if so, how?***

NRECA strongly believes that the Commission should encourage joint ownership arrangements with non-public utilities. However, granting investor-owned utilities incentive

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[46] This filing, made in Docket No. ER19-1895, proposes to eliminate the $5 million cost threshold for projects, remove the joint model requirement, and adds additional benefit metrics to justify projects.

[47] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 (2018), *order on reh'g*, Order No. 845-A, 166 FERC ¶ 61,137 (2019) (*reh'g pending*).

[48] Order No. 1000 at PP 203-224.

adders to offer non-jurisdictional utilities is not the right approach—this would add another layer of costs to consumers. Instead, the Commission should impose as a precondition to eligibility for incentive rate treatment a demonstration by the public utility that it has offered joint ownership opportunities for transmission upgrades and new facilities, including third-party participation in the construction of such facilities, to other LSEs in the region, including cooperatives and public-power entities, on reasonable terms and conditions, or a demonstration as to why joint ownership was impracticable, unlawful, or otherwise unwarranted, making such an offer unnecessary. Such a precondition would be enable the Commission's incentive policies to better meet Congress' objectives in FPA section 219 and the Commission's objective in Order No. 679 "to benefit consumers by providing real incentives to encourage new infrastructure, not simply increasing rates in a manner that has no correlation to encouraging new investment."[49] Although NRECA believes the precondition should apply to *any* incentive rate treatment, if the Commission disagrees, at a bare minimum, the Commission should require the precondition to any return-enhancing incentives.

Because of their access to different capital markets and different capital structure, cooperative and public-power participation in future transmission projects could help ensure that needed facilities get built at the lowest overall cost. Moreover, cooperative and public-power participation could well reduce the need for incentive rate treatments by jurisdictional public utilities, *e.g.*, by providing needed cash flow or reducing financial uncertainties. Joint ownership of transmission can allow transmission dependent cooperatives and other public power entities to receive auction revenue rights (ARRs) which can help reduce overall transmission costs and

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[49] Order No. 679 at P 6.

encourage transmission investments in areas with chronic reliability issues or certain geographic areas that are underserved.

Congress clearly contemplated encouragement by the Commission of ownership of transmission facilities by a broader universe of entities than just public utilities, as section 219(b)(1) charges the Commission to promote capital investment in transmission, "regardless of the ownership of the facilities." Making the offering of joint ownership opportunities a precondition to transmission incentives would also comport with Congress' contemporaneous mandate in subsection 217(d)(4) of the FPA that the Commission "shall exercise its authority under the [FPA] in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities … ." Such a precondition would also further the express purposes of the Commission rule stated in section 219—encouraging transmission infrastructure investment "for the purpose of benefiting consumers," and "promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities."

The landscape has changed since the Commission rejected arguments by NRECA and others in Order No. 679-A that offering public power participation in transmission should be a condition of any proposed incentive rate treatment. Part of the Commission's rationale for so doing was that it had initiating the rulemaking that resulted in Order No. 890.[50] Since the issuance of Order No. 679, not only has the Commission required each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process, pursuant to Order No. 890, but it has also required each public utility

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[50] Order No. 679 at P 102.

transmission provider to participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation, pursuant to Order No. 1000. Thus, while it may be true that "the Commission cannot compel investment or certain types of investment,"[51] the Commission certainly can condition the granting of transmission incentives on public utility transmission providers giving non-jurisdictional utilities the opportunity to participate in ownership of transmission facilities. *See* Section II.B, above.

Using the Order No. 1000 framework, the Commission can—and should—require a public utility transmission owner seeking incentive rate treatment for a particular project for a new or upgraded facility to have offered joint ownership to any non-jurisdictional entity to which the project costs will be allocated in the transmission owner's or RTO/ISO rates, or demonstrate why joint ownership was impracticable, unlawful, or otherwise unwarranted, making such an offer unnecessary. This precondition could work either in the sponsorship model used by some regions, where parties submit proposed projects to address a need identified by the RTO/ISO, or under a competitive-solicitation model.

### 10. Order No. 1000 Transmission Projects

***Q 52) Should these or other incentives be granted automatically for transmission projects selected in a regional transmission plan for purposes of cost allocation?***

No. There has been no showing that the current practice of case-by-case review is inefficient or not working. Pre-approving such incentives would inappropriately excuse applicants from their statutory obligation to demonstrate that their successful bid will result in just and reasonable rates, terms and conditions of service. FERC should review incentive

[51] *Id*. (emphasis in original).

requests on a case-by-case basis. Regarding Order No. 1000 transmission projects, NRECA does not believe that such projects should be evaluated differently than other transmission projects with regard to eligibility for incentives, and believes that cost allocation is the primary barrier to approval and construction of interregional projects.

## C. Existing Incentives

### 1. ROE Adder Incentives

#### a. Transmission-only Companies

***Q 57) Does the Transco business model continue to provide sufficient benefits to merit transmission incentives? What information should an entity seeking a Transco incentive provide to demonstrate sufficient benefits?***

NRECA does not believe the evidence demonstrates that the Transco business model provides benefits to customers. To the contrary, the Transco business model, including the availability of double leveraging, provides significant benefits to Transco investors. Moreover, Transcos face *less* risk than vertically integrated utilities, since they have only one regulator and provide a single service largely insulated from competition. The ROE for transmission investments has trended higher than those for generation assets, reducing any imbalance in the competition for capital between generation and transmission functions. In light of these factors, NRECA does not believe Transcos should receive higher returns. Rather, the Commission should be monitoring Transcos to ensure that their costs are not so high such that the resulting rates are unjust and unreasonable. Additionally, acquisition premiums for Transco creation should not be allowed unless it can be demonstrated that the cost of the premium to customers does not outweigh the demonstrable benefits (if any) from the Transco formation.

NRECA agrees with Commissioner Glick's discussion of the evolution of the need for the Transco incentive. The Commission originally adopted this incentive in order to encourage the Transco model because "by eliminating competition for capital between generation and transmission functions and thereby maintaining a singular focus on transmission investment, the Transco model responds more rapidly and precisely to market signals indicating when and where transmission investment is needed."[52] As Commission Glick explained, since the Commission issued Order No. 679, "the electricity sector has changed dramatically in the intervening twelve years, not least because of subsequent Commission reforms, such as Order No. 1000, that have fundamentally altered the transmission landscape. It is certainly not clear that Transcos are superior to other public utilities that can and do invest in transmission facilities—including competitively developed transmission facilities—or that awarding Transcos a higher ROE actually leads to greater transmission investment."[53] As NRECA recommends with respect to the other incentives that have been in place since the Commission adopted its incentive policies, the Commission should at a minimum undertake an analysis to evaluate whether, in fact, those Transcos that have been awarded this ROE adder have in fact constructed transmission facilities more quickly and somehow in a manner more responsive to market signals than transmission owners/developers that have not received this incentive adder. Without any such evaluation, the Commission would be making expensive policy decisions without any evidentiary basis for them.

***Q 58) Should the Transco incentive remain available to Transcos that are affiliated with a market participant? If so, how should the Commission evaluate whether a Transco is sufficiently independent to merit an incentive?***

Assuming the Commission continues to offer any incentives for adoption of the Transco business model, such incentives should not be allowed for entities affiliated with vertically integrated utilities, even if the affiliation consists of so-called passive ownership. In determining

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[52] Order No. 679 at PP 224.

[53] *GridLiance West Transco LLC*, 164 FERC ¶ 61,049 (2018) (Commissioner Glick, concurring).

that Transcos should have access to incentives beyond those available to other transmission owners, the Commission in Order No. 679 stated that "By eliminating competition for capital between generation and transmission functions and thereby maintaining a singular focus on transmission investment, the Transco model responds more rapidly and precisely to market signals indicating when and where transmission investment is needed."[54] A Transco affiliated with vertically integrated utilities does not eliminate competition for capital or maintain a singular focus on transmission investment, and thus should not be rewarded as if it did those things.

***Q 60) Should the Transco incentive exclude assets that a Transco buys, rather than develops?***

Assuming the Commission continues to offer any incentives for adoption of the Transco business model, such incentives should apply only to assets developed by the Transco. Given that the justification for offering incentives to Transcos centers on the supposition that they will raise capital for the sole purpose of investing in beneficial transmission projects, there is no justification for providing an incentive to a project that is already in place simply because on type of business organization sells the project to another type of business organization. Purchase by the Transco will not change the extent to which the project ensures reliable service or alleviates congestion.

### b. <u>RTO/ISO Participation</u>

***Q 61) Should the Commission revise the RTO-participation incentive?***

NRECA is not taking a position on whether the Commission should revise the RTO-participation incentive. Individual members of NRECA may weigh in separately on this issue.

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[54] Order No. 679 at P 224.

***Q 62) Should the Commission consider providing incentives other than ROE adders for utilities that join RTO/ISOs, such as the automatic provision of CWIP in rate base or the abandoned plant incentive for all transmission-owning members of an RTO/ISO? If so, what other types of incentives would be appropriate?***

No. As discussed above in Section II.E, NRECA does not believe it would be appropriate to provide any incentives automatically, whether to transmission-owning members of an RTO/ISO or otherwise. Incentives should be granted on a case-by-case basis so that the Commission can adequately evaluate whether or not they are just and reasonable and are sufficiently narrowly tailored to meet the need.

***Q 63) If the Commission continues to provide ROE adders for RTO/ISO participation, what is an appropriate level for an ROE adder?***

NRECA is not taking a position on this question; see response to Question 61, above.

***Q 64) Should the RTO-participation incentive be awarded for a fixed period of time after a transmission owner joins an RTO or ISO?***

NRECA is not taking a position on this question; see response to Question 61, above.

***Q 66) In Order No. 679, the Commission found that "the basis for the incentive is a recognition that benefits flow from membership in such organizations and the fact that continuing membership is generally voluntary." Should voluntary participation remain a requirement for receiving RTO/ISO incentives?***

NRECA is not taking a position on this question; see response to Question 61, above.

**c. <u>Advanced Technology</u>**

NRECA supports development and deployment of advanced technologies and supports the Commission's approach articulated in the 2012 Incentives Policy Statement:

> The Commission continues to encourage the deployment of advanced technologies that "increase the capacity, efficiency, or reliability of an existing or new transmission facility." However, the Commission is concerned that its current approach may contribute to confusion, including with respect to the distinct standards that the Commission applies in these two contexts. To address this concern, the Commission will no longer consider requests under Order No. 679 for a stand-alone incentive ROE

> based on an applicant's utilization of an advanced technology. Instead…the Commission will consider transmission projects that apply advanced technologies as indicative of the types of projects facing risks and challenges that may warrant an incentive ROE."[55]

As discussed above in Section II.D.2, NRECA believes that the Commission should not develop separate incentives for advanced technologies. Rather, requests for incentives should continue to be evaluated in the context of the existing risks and challenges rubric. To the extent a specific technology is not highly commercialized but has high potential to advance the state-of-the-art for the industry, but there are significant financial risks in developing the technology, the project should still be eligible for incentives under the Commission's risks and challenges approach. To the extent the Commission nonetheless decides to implement stand-alone technology incentives, the Commission should create guidelines to help stakeholders understand the types of technologies that the Commission is attempting to promote.

### 2. Non-ROE Transmission Incentives

#### a. Regulatory Asset/CWIP

***Q 70) Should the Commission continue to provide regulatory asset treatment and CWIP as incentives? Should these incentives be granted automatically to certain types of transmission projects? If so, how would the Commission determine what types of transmission projects?***

NRECA believes that risk-reducing incentives such as regulatory asset treatment or recovery of CWIP can be acceptable incentives so long as the incentives are necessary to facilitate construction of the transmission project in question, and so long as provision of those incentives result in customer benefits.

NRECA does not believe there are any circumstances under which these incentives should be awarded automatically.

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[55] 2012 Incentives Policy Statement at P 23 (quoting Order No. 679 at P 298).

***Q 71) Should the costs of unsuccessful Order No. 1000 proposals be recoverable through regulatory asset and deferred pre-commercial cost recovery incentives? If so, what costs are appropriate for recovery?***

Assuming that the Commission means unsuccessfully submitted in an Order No. 1000 planning process, the answer is "no." Customers should not pay if they do not benefit, and investors should not be shielded from all risk. If costs of unsuccessful Order No. 1000 proposals were recoverable through regulatory asset and deferred pre-commercial cost recovery incentives, costs to ratepayers would increase without any commensurate benefit. The benefit of competition to ratepayers is the reduced cost associated with a *completed* project; there are no benefits associated with bids that do not result in a completed project. While there is a modest amount of financial risk for a developer that submits what is ultimately an unsuccessful bid, this risk is very small relative to the benefit of winning the project. NRECA does not see any justification for the Commission to create incentives for developers to bid on more projects.

**b. <u>Hypothetical Capital Structures</u>**

***Q 72) Should the Commission continue to utilize hypothetical capital structures as a transmission incentive? If so, what entities should be eligible to apply for a hypothetical capital structure?***

Hypothetical capital structures are appropriate where there is a demonstrated need. For example, non-jurisdictional public power entities do not issue stock and have successfully applied for and obtained this incentive.[56] This incentive helps create a more level playing field for non-public utilities to own and operate large transmission projects. Without it, non-public utilities are at a disadvantage to public utilities in terms of total rate of return from transmission

[56] *See, e.g., Midcontinent Indep. Sys. Operator, Inc., Dairyland Power Cooperative,* 161 FERC ¶ 61,301, at PP 1, 19 (2017) (granting Dairyland a hypothetical capital structure of 45 percent equity and 55 percent debt for the life of the debt used to finance project, facilitating Dairyland's nine percent ownership share in project); *Midcontinent Indep. Sys. Operator, Inc. and Dairyland Power Cooperative*, 152 FERC ¶ 61,019, at PP 1, 4, 22 (2015) (approving Dairyland's request for hypothetical capital structure of 40 percent equity and 60 percent debt, facilitating Dairyland's expected five percent ownership share in project).

projects due to higher debt to equity ratios of non-public utilities. Given that non-public utilities serve the majority of the land mass of the United States, the Commission should promote policies that nurture the financial health of these companies, allowing them the benefits of ownership of transmission incentives rather than simply paying the ownership costs of projects owned by public utilities.

In no case should a hypothetical capital structure be granted automatically. In addition, any hypothetical capital structure allowed by the Commission should bear some semblance to reality. The specific incentives proposed by the Commission should be designed to promote sufficient transmission investment without undue reliance on hypothetical capital structures that may have the effect of substantially increasing the actual rate of return on new transmission investment. If a project is refinanced, the Commission should reexamine the reasonableness of the hypothetical capital structure. Moreover, this incentive should only be used when the facts of a particular situation suggest it is warranted, and the additional cost of permitting use of a hypothetical capital structure can be justified on cost-benefit analysis.

***Q 76) Should the Commission provide a consistent hypothetical structure (e.g., 50 percent debt and 50 percent equity)? Alternatively, should the Commission cap the equity percentage at some upper limit (e.g., 50 percent)?***

A hypothetical capital structure of 50 percent debt and 50 percent equity is a reasonable default incentive, since it is consistent with the capital structure of many public utilities. Applicants or intervenors should be permitted to provide evidence that a different structure is warranted in a particular case.

### c. Recovery of Cost of Abandoned Plant

***Q 77) Should the Commission grant the abandoned plant incentive automatically, rather than on a case-by-case basis? Under what circumstances might an automatic award of the abandoned plant incentive be appropriate?***

NRECA supports continuation of the abandoned plant incentive; as discussed above in Section II.C, risk-reducing incentives like the abandoned plant incentive are preferable to return-enhancing incentives. However, the Commission should clarify how the incentive applies if a project has multiple owners. If the majority owner cancels or abandons a project for reasons *within* its control, the cancellation or abandonment nonetheless may be beyond the control of minority owners, and they should not be precluded from recovering their prudently-incurred costs even if the majority owner cannot.

### d. Accelerated Depreciation

***Q 80) Should the Commission continue to consider accelerated depreciation as an incentive?***

Accelerated depreciation raises issues of intergenerational equity, and should therefore be used sparingly. Accelerated depreciation should be allowed, if at all, only for new investment. Additionally, a public utility receiving permitted to use accelerated depreciation as an incentive should also be required to accept, in exchange, a reduced ROE to reflect the lower risk and improved cash flow that will result from its use of accelerated depreciation.

***Q 82) Should the Commission grant an accelerated depreciation incentive with a generic depreciation period or continue to determine such a period on a case-by-case basis?***

If the Commission utilizes accelerated depreciation as an incentive, the depreciation period should be determined on a case-by-case basis, and should be no shorter than necessary to address the risks that might otherwise prevent construction of the project in question.

### D. Mechanics and Implementation

#### 1. Duration of Incentives

***Q 83) Should the Commission limit the duration of a granted transmission incentive? If so, should this limit be based on the type of incentive granted?***

Whether transmission incentives should be time limited depends on the nature of the incentive. NRECA is not taking a position on whether risk-reducing incentives should be limited in duration. However, ROE incentive adders for transmission projects should be designed to sunset after a set period.[57] First, once the project is in service, the present value of the amortized value of the adder that customers will pay over the life of the project will likely exceed the benefits the customers will receive, thus rendering the incentive excessive. Second, the project owner's cost of equity capital is almost certain to change during the expected life of transmission facilities, which requires re-examining whether the base ROE plus adder provides an excessive overall return. Third, a transmission owner that believes its allowed return (base plus adder) is not consistent with the cost of capital can always file for a higher base ROE pursuant to FPA section 205, which will again trigger a re-examination of the overall allowed return is excessive.

***Q 84) How should the Commission structure a durational component to its incentives? For example, should the Commission provide that transmission incentives automatically sunset after a certain period?***

Yes (see response to # 83, above)

***Q 85) Should the Commission provide that a transmission incentive can be eliminated or modified upon a material change to the transmission project? How would such an elimination or modification be implemented? What should constitute such a material change? How would the Commission and interested parties be informed of such a material change?***

[57] As noted in the response to Question 61, NRECA is not taking a position on whether ROE adders for RTO participation are appropriate, and thus is not taking a position on the duration of such adders.

NRECA agrees that the Commission should retain the authority to eliminate or modify transmission incentives. Congress gave the Commission the authority to award incentives "for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."[58] If circumstances change such that a project for which incentives were awarded is no longer likely to provide the expected benefits to consumers, or is likely to provide only reduced benefits, the Commission should maintain the authority to eliminate or modify the incentives so that any incentives received by the developer remain proportional to the benefits received by consumers. Similarly, if the Commission continues to provide incentives for Transcos, it must have a mechanism to eliminate or modify the incentive if the Transco becomes less independent of market participants.

### 2. Case-by-Case vs. Automatic Approach in Reviewing Incentives Applications

***Q 90) What are the benefits and drawbacks of granting incentives on a case-by-case basis, as compared to being granted automatically, with or without related threshold criteria? Would an automatic approach based on established threshold criteria provide additional certainty? If so, how?***

As discussed above in Section II.E, transmission incentives should be granted only on a case-by-case basis. Project-by-project review is necessary to enable the Commission to assure itself that the incentives granted are proportional to the risks posed by the project and the benefits to be received by customers. It is also necessary to enable the Commission to fulfill its obligation to ensure that rates remain just and reasonable.

One way in which the Commission could become more efficient in processing case-by-case applications would be to increase transparency to stakeholders through the use of goal posts or metrics regarding what criteria could pass the case-by-case examination.

58 FPA section 219(a).

### 3. <u>Interaction Between Different Potential Incentives in Determining Correct Level of ROE Incentives</u>

***Q 93) Should the Commission establish a more formulaic framework for determining the appropriate level and combination of incentives? If such a framework is created, what elements should it include?***

As discussed above in Section II.E, NRECA believes incentives must be considered on a case-by-case basis, and not automatically pursuant to a formula. The need for case-by-case review is especially critical where transmission owners seek different combinations of incentives. The Commission must examine the totality of the incentives and their impact on the justness and reasonableness of the resulting rate, and automated granting of incentives would make this impossible.

***Q 95) The Commission's current policy is that the total ROE may not exceed the zone of reasonableness. If a transmission project qualifies for ROE incentives, should there be an upper limit or range that the total ROE cannot exceed? If so, what is the appropriate limit or range? Should this vary based on how the Commission sets base ROE?***

Under no circumstances should a total ROE be permitted to exceed the top of the zone of reasonableness. If the Commission sets the base ROE in a manner that produces a very wide zone of reasonableness, it may very well be appropriate to set a lower limit on total ROE than the top of the zone of reasonableness.

## IV. <u>CONCLUSION</u>

NRECA appreciates the opportunity to provide its input to the Commission on these important inquiries and respectfully requests that the Commission take its views into consideration as it fashions any proposed changes to its incentives and incentive policies. In particular, NRECA urges the Commission to be very cautious about proposing new incentives before it figures out ways to determine if existing incentives are accomplishing their intended objectives; to ensure that non-jurisdictional utilities have comparable opportunities to obtain incentives and to establish conditions on transmission incentives that encourage joint ownership opportunities; and not to make any radical changes to its risks/challenges approach to transmission incentive policies, but rather, to incorporate new incentive objectives into the existing framework.

Respectfully submitted,

NATIONAL RURAL ELECTRIC
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June 26, 2019