UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF THE DELAWARE MUNICIPAL ELECTRIC CORPORATION, INC.

Delaware Municipal Electric Corporation, Inc. ("DEMEC") respectfully submits these comments to the Federal Energy Regulatory Commission ("Commission") in response to the Commission's Notice of Inquiry ("NOI") issued on March 21, 2019,[1] seeking comments on the scope and implementation of its electric transmission incentives regulations and policy established in Order No. 679[2] and implementing regulations[3] pursuant to Section 219 of the Federal Power Act ("FPA").[4] The Order No. 679 policy, as refined in the 2012 Policy Statement, is referred herein as to the Commission's "Incentives Policy." In support thereof, DEMEC states as follows:

I. DESCRIPTION OF DEMEC

DEMEC is a joint action agency formed under Delaware law. The Members of DEMEC are the Delaware Cities and Towns of Newark, Milford, New Castle, Seaford,

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1 *Inquiry Regarding the Commission's Elec. Transmission Incentives Policy*, 166 FERC ¶ 61,208 (2019) ("NOI").

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).

3 The Commission's incentive regulations under Order No. 679 are set forth in 18 C.F.R. § 35.35 (2019).

4 *See* NOI at P 1 & nn.1-2 (citing Section 1241 of the Energy Policy Act of 2005, EPAct 2005, Pub. L. No. 109-58, sec. 1261 *et seq.*, 119 Stat. 594 (2005), which enacted Section 219 of the FPA, 16 U.S.C. 824s(a)). The Commission refined its approach to transmission incentives in *Promoting Transmission Investment Through Pricing Reform,* 141 FERC ¶ 61,129 (2012) ("2012 Policy Statement"), but did not alter the Commission's regulations or Order No. 679's basic approach to granting transmission incentives. NOI at P 1.

Lewes, Smyrna, Clayton, Middletown, and Dover. DEMEC is a generation owner and the PJM Interconnection L.L.C. ("PJM") Load Serving Entity ("LSE") for eight of these municipal utilities. In total, DEMEC's Members have a peak load of over 470 MW. DEMEC is a transmission customer taking service under the Open Access Transmission Tariff administered by PJM at the Delmarva Power and Light Company ("Delmarva" or "DPL") zone rate.[5]

II. INTRODUCTION AND EXECUTIVE SUMMARY

The NOI seeks comment on the scope and implementation of the Commission's Incentives Policy established pursuant to Section 219 of the FPA, which required the Commission to establish incentive-based rate treatments for public utilities. Importantly, Section 219 stated that the purpose of the incentive rates is to benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.[6]

As a transmission customer, DEMEC has seen its transmission rates increase significantly over the past decade.[7] As a transmission dependent LSE, DEMEC supports the development of needed transmission at just and reasonable rates, terms, and

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5 Delmarva has a formula rate which uses a template populated with entries taken from Delmarva's FERC Form 1 using the Uniform System of Accounts.

6 16 U.S.C. § 824s(a). Section 219 also required that the Commission ensure that the incentive-based rates meet the "just and reasonable" standard contained in FPA Sections 205 and 206. 16 U.S.C. § 824s. *See also* 18 C.F.R. § 35.35 (c) ("All rates approved under the rules of this section . . . are subject to" the filing requirements and substantive requirements of sections 205 and 206 of the FPA.).

7 DEMEC's transmission costs increased by over $4 million from 2011 to 2018. *See* Delaware Municipal Electric Corporation, *Annual Continuing Disclosure Report 2012* at 12, available at https://emma.msrb.org/EP674242-EP525408-.pdf (reporting that operating expenses included $6,733,030 for transmission charge in 2010); *Annual Report 2018* at 3, available at http://www.demecinc.net/wp-content/uploads/2019/03/DEMEC-2018-AuditedFS-High-Res.pdf (reporting that operating expenses included $10,907,916 for transmission charge in 2018). As a transmission customer in the Delmarva zone in PJM, DEMEC also notes that the 2019 Delmarva zone transmission rates have more than quadrupled since 2006 (*i.e.*, $10,034/MW-Yr in 2006 to $43,744 in 2019).

conditions to ensure that DEMEC can satisfy its service obligations. However, DEMEC has not seen any empirical evidence tying costs of incentive rates with any measurable benefits to the transmission service it has received. DEMEC has also not seen any objective empirical evidence on the need for additional incentives to promote further transmission investment to ensure reliability or reduce the cost of delivered power. As such, DEMEC recommends that the Commission refrain from granting new incentives unless there is substantial evidence to justify the grant of any such new incentives to develop transmission to benefit consumers. *See* Section III.A, below.

In addition, a significant amount of transmission investment that has been developed relates to projects that have not been fully vetted and approved in open and transparent regional transmission planning processes and have not been deemed necessary for reliability or economic purposes by a transmission planning region (*e.g.*, Supplemental Projects[8] in PJM).[9] These projects, whether or not fully vetted with stakeholders during the planning stages, benefit from a presumption of prudence unless challengers take on the significant burden and expense of casting a serious doubt on the

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8 Supplemental Projects are "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to [Regional Transmission Expansion Planning ("RTEP")] models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM." In light of the Commission's findings in *Monongahela Power Co.*, 162 FERC ¶ 61,129, *reh'g denied*, 164 FERC 61,217 (2018) as to coordination and transparency deficiencies with the PJM Transmission Owners' planning practices for Supplemental Projects, the PJM Transmission Owners revised their planning processes, although they are still planned for by the PJM Transmission Owners through a process set forth in Attachment M-3 of PJM's Open Access Transmission Tariff.

9 *See e.g.*, Cost Savings Offered by Competition in Electric Transmission at 24-25 (Apr. 2019), available at: https://brattlefiles.blob.core.windows.net/files/15987_brattle_competitive_transmission_report_final_with_data_tables_04-09-2019.pdf (Almost half (47 percent) of transmission investment in RTO/ISO regions during 2013 to 2017 was not subject to a full RTO/ISO planning process with associated stakeholder review.).

initial presumption of prudence.[10] This is the case even for projects that grossly exceed their initial cost estimates and for projects for which insufficient information has been provided to objectively understand the needs, alternatives considered, and benefits of the project. Thus, to foster the consumer protection purpose of the FPA, the Commission should condition the grant of the incentive rates on approval of the project in an open and transparent regional transmission planning process. For projects that are not subject to a transmission planning region's vetting on reliability or economic needs and benefits, the Commission should require additional information on costs-benefits of the project to be deemed eligible for incentive rate treatment. Projects that have not been vetted in any open and transparent planning process should be ineligible for transmission rate incentives. *See* Section III.B, below.

The Commission should also require incentive rate applicants to provide additional information and encourage transmission developers to provide firm cost estimates and time commitments to ensure transparency on the costs and benefits associated with the transmission that is developed for the purposes of benefitting consumers. *See* Section III.C, below.

As far as the framework used to evaluate incentive applications, DEMEC submits that it is imperative to consider both the benefits of a particular project as well as the nexus between the risks and challenges faced by the applicant and the total package of incentives requested. Both tests are fundamental to ensuring that consumers are benefiting from the transmission investment from both a reliability and cost-perspective as Section 219 intended. *See* Section III.D, below.

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[10] *Potomac-Appalachian Transmission Highline, L.L.C.*, 158 FERC ¶ 61,050 at P117 (2017) ("[T]he presumption of prudence standard gives PATH extraordinary advantage . . . placing the burden of presenting evidence on the intervenors to raise serious doubts as to the prudence of expenditures.").

When incentives are warranted, the Commission should retain its current approach of focusing on risk-reducing incentives (*e.g.*, 100 percent of prudently incurred costs of transmission facilities that are abandoned for reasons beyond the applicant's control ("Abandoned Plant Incentive"), 100 percent Construction Work in Progress ("CWIP Incentive"), recovery of 100 percent of pre-commercial costs as an expense or as a regulatory asset ("Pre-Commercial Cost Incentive"), *over* return-enhancing incentives (*e.g.*, return on equity ("ROE"), adders or hypothetical capital structures)). *See* Section III.E, below.

A case-by-case review is also essential to ensuring that the rates approved, including with incentives granted, are just and reasonable and not unduly discriminatory or preferential consistent with Section 219's mandate. The Commission should not shift the burden of proof on to transmission customers by presuming the applicability, or automatically grant, of any incentives, including risk-reducing incentives. *See* Section III.F, below.

The NOI also asks questions that pertain to incentive objectives, and particularly as to whether certain expected benefits or project characteristics warrant transmission incentives. In this regard, improving and maintaining reliability, and complying with North American Electric Reliability Corporation ("NERC") Reliability Standards, are core functions of public utility transmission providers.[11] Public utility transmission providers are already permitted the opportunity to recover their full cost of service and earn a just and reasonable return on their investment, which accounts for the risks and

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[11] 16 U.S.C. § 824o (mandating that NERC file reliability standards with FERC, and authorizing Electric Reliability Organizations to enforce reliability standards on public utilities).

capital needed to attract capital investment.[12] Thus, the Commission should not provide incentive rate treatment simply because a public utility transmission provider complied with its legal obligations. *See* Section III.G, below.

With respect to the NOI questions pertaining to existing incentives, the Commission should revise its current approach of routinely granting a full 50 basis point ROE adder for continued membership in an RTO/ISO and of granting such an ROE adder to the transmission provider's entire rate base. *See* Section III.H, below.

DEMEC also provides responses to a miscellaneous set of specific questions in the NOI. *See* Section III.I, below. Finally, DEMEC addresses certain matters of mechanics and implementation of the Incentives Policy. *See* III.J, below.

III. COMMENTS

The NOI requests comments on a myriad of questions regarding the Commission's Incentives Policy as established under Order No. 679 and refined in the 2012 Policy Statement. DEMEC provides comments regarding an overall approach to the Incentives Policy and responds to certain threshold and incentive-specific questions raised in the NOI below.

A. The Commission Should Refrain from Adding New Incentives Absent Empirical Evidence that Additional Incentives Are Needed for the Purpose of Benefiting Consumers.

FPA Section 219 was enacted as part of EPAct 2005 in response to concerns about the reliability of the country's aging transmission system and the decline in needed

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[12] *Indiana & Michigan Power Co.*, 4 FERC ¶ 61,316 at p. 61,739 (1978) (stating that a cost-of-service tariff allows the company to maintain a "steady stream of revenues" and provides the company with a "very real advantage"); *S. Carolina Generating Co.*, 40 FERC ¶ 61,116 at p. 61,311 (1987) (describing that the subsidiary has less risk than its parent company because the "cost-of-service tariff guarantees [the subsidiary] a constant revenue stream").

transmission investment.[13] As the NOI recognizes, since enactment of Section 219 almost fourteen years ago and issuance of Order No. 679 nearly thirteen years ago, "the landscape for planning, developing, operating, and maintaining transmission infrastructure has changed considerably."[14] These changes include a significant increase in transmission investment.[15] The Commission has also issued Order No. 1000, which builds on the Order No. 890[16] planning requirements, and requires regional transmission planning and cost allocation by public utility transmission providers and competition in the development of new regional transmission projects that are selected for regional cost allocation.[17]

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13 *See* President Bush Signs Into Law a National Energy Plan, The White House Office of Communications, Office of the Press Secretary (Aug. 8, 2005) ("The energy bill will help modernize our aging energy infrastructure to help reduce the risk of large-scale blackouts and minimize transmission bottlenecks."); H.R. Rep. 109-215(I), 171 ("investment in electric transmission expansion has not kept pace with electricity demand. . . . Legislation is needed to address the issues of transmission capacity, operation, and reliability."); 151 Cong. Rec. H6943-01, 151 (the legislation "also encourages investment in transmission lines to eliminate bottlenecks in the electric grid."). *See also* Order No. 679-A at P 3 ("Section 219 was enacted because of a long decline in transmission investment that is threatening reliability and causing billions of dollars in congestion costs.").

14 NOI at P 13. *See also id.* at P 2.

15 *See, e.g.*, 2017 FERC Staff Transmission Metrics Report (Oct. 2017), available at: http://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf (stating "Staff identified 9,754 projects that went into operation between 2008 and 2015, representing approximately $77 billion (in 2015 dollars) of incremental transmission investment," with approximately three-quarters of this total "invested in projects primarily involving new and upgraded transmission lines," and the remaining quarter "invested in projects involving substations and other non-line facilities."). *See also, e.g.*, Edison Electric Institute Historical and Projected Transmission Investment (Nominal Dollars) (updated Oct. 2018), available at: http://www.eei.org/issuesandpolicy/transmission/Documents/bar_Transmission_Investment.pdf (depicting that transmission investment increased from $15.6 billion in 2012 to $21.9 billion in 2017; and projecting transmission investment of $23.7 billion in 2018 and $20.9 billion in 2021).

16 *Preventing Undue Discrimination and Preference in Transmission Serv.*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), *on reh'g and clarification*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *on reh'g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *clarified*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

17 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils.*, 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 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).

The Commission noted in the 2012 Policy Statement that it had evaluated more than 85 applications representing over $60 billion in transmission investment.[18] DEMEC also estimates that the projected rate base for projects that were granted incentives went from approximately $3.8 billion in 2006 to $63.7 billion in October 2011. However, there does not appear to have been any empirical evidence to suggest that new types of incentives are needed to ensure the development of cost effective and efficient transmission infrastructure to benefit consumers consistent with the purpose of Section 219. Nor is there any assessment to DEMEC's knowledge of the cost-benefit of the transmission projects provided incentives to date.

In a 2017 FERC Staff Transmission Metrics Report, which was focused on Order No. 1000 implementation, and in which FERC Staff reported approximately $77 billion in incremental transmission investment between 2008 and 2015, FERC Staff stated "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."[19] While this points to the need for region-specific assessment on transmission needs and development and transparency on cost-benefits of the investments that are being made, this is certainly not a ringing endorsement of the need for additional incentives.

Costs for transmission customers, such as DEMEC, have risen substantially (from $10,034/MW Yr in 2006 to $43,744/MW-Yr in 2019, a 336% increase) in the last decade whereas utilities have various avenues to reduce their risks. For example, *inter alia*,: (1) base ROEs already account for the amount of ROE needed to attract capital to

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[18] 2012 Policy Statement at P 2.

[19] 2017 FERC Staff Transmission Metrics Report at 6.

incentivize new investment;[20] (2) formula rates significantly reduce risks of cost recovery;[21] (3) existing rate policies provide for sharing of risks between public utility shareholders and transmission customers (*e.g.*, 50-50% cost sharing of abandoned plant costs[22] and permitting utilities to file to include CWIP in rate base[23]); (4) public utility transmission providers enjoy a presumption that their utility management decisions are prudent, with challengers required to establish a serious doubt as to the prudence of the utility's actions;[24] and (5) the current Incentives Policy, which provides the opportunity to receive risk-reducing incentives before seeking an incentive ROE based on a project's

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[20] *See, e.g., Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. 679, 693 (1923) ("*Bluefield*") (stating that the ROE approved by the Commission should "be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."); *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) ("*Hope*") (stating that the ROE should be "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.").

[21] *See, e.g.*, Order No. 679 at P 386 (noting that "formula rates can provide certainty of recovery that is conducive to large transmission expansion programs.").

[22] *See, e.g., San Diego Gas & Elec. Co.*, 146 FERC ¶ 61,066 at PP 23-24 (2014) (stating 100 percent abandoned plant recovery is atypical and that the more standard approach is a "50/50 sharing of cancelled project costs"); *The Potomac Edison Co.*, 165 FERC ¶ 61,168 at P 18 (2018) (granting "50 percent of the prudently-incurred project costs expended prior to the date of the issuance of [the Commission's] order.").

[23] *See, e.g., Construction Work In Progress for Pub. Utilities; Inclusion of Costs in Rate Base*, Order No. 298, 48 Fed. Reg. 24,323 (June 1, 1983), *order on reh'g*, Order No. 298-B, 48 Fed. Reg. 55,281 (Dec. 12, 1983) (permitting utilities to file to include as CWIP in rate base the investment in construction projects regardless of the financial condition of the utility).

[24] *See, e.g., BP Pipelines (Alaska) Inc.*, 153 FERC ¶ 61,233 at P 13 (2015) ("The regulated entity has the burden of proof to establish prudence. However, in order to ensure that rate cases are manageable, a presumption of prudence applies until the challenging party 'creates a serious doubt as to the prudence of an expenditure . . . .' Serious doubt must be more than a 'bare allegation of imprudence,' but this threshold may not be so demanding that it effectively reverses the statutory burden of proof. Once such serious doubt has been raised, the pipeline has 'the burden of dispelling these doubts and proving the questioned expenditure to have been prudent.'") (internal footnotes and citations omitted); *Pacific Gas & Elec. Co.*, Initial Decision, 165 FERC ¶ 63,001 at P 623 (2018) (applying the standard of "serious doubt" as to the prudence of the utility's expenditure).

risk and challenges,[25] significantly reduces the transmission owner's risk.[26] Transmission assets are viewed as safe investments with predictable returns[27] with 100 % guaranteed cost recovery. In considering whether and how to revise its Incentives Policy, the Commission should not lose sight of Section 219's purpose of benefitting consumers. Accordingly, the Commission should refrain from expanding its Incentives Policy to grant new incentives, particularly return-enhancing incentives, unless the Commission establishes empirical evidence that demonstrates that: (1) the incentives granted to date have measurably benefitted consumers consistent with the purpose of FPA Section 219; (2) there is a nation-wide (as opposed to region-specific) need for transmission investment that is not being pursued; and (3) the lack of such investment is correlated to the existing Incentives Policy, as opposed to other factors unrelated to the Incentives Policy.

To be clear, DEMEC is not opposed to the investment in needed transmission. However, to ensure that the Commission's Incentives Policy is meeting the statutory mandate of benefitting consumers, the Commission should refrain from revising its current approach to providing new incentives, particularly where any concerns regarding the lack of development of needed or beneficial transmission are not a product of the current Incentives Policy. If there is a demonstrable pattern of lack of needed transmission, the Commission should first confirm if the lack of needed transmission

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[25] 2012 Policy Statement at P 11.

[26] DEMEC estimates that between 2006-May 2019, the Commission has issued approximately 163 orders under its Incentives Policy of which 84 orders have granted applicants the Abandoned Plant Incentive, and 51 orders granted the CWIP Incentive.

[27] The Quadrennial Energy Review at EL-50 (Apr. 2015), available at: https://www.energy.gov/sites/prod/files/2015/09/f26/QER_AppendixC_Electricity.pdf (explaining that transmission assets are viewed as safe investments with predictable returns).

development is related to problems with the transmission planning processes on a region-specific basis, or factors outside the Commission's jurisdiction.[28]

B. The Commission Should Condition the Grant of Incentive Rates to the Project Being Fully Vetted and Approved in an Open and Transparent Transmission Planning Process that Considers the Reliability or Economic Needs and Benefits of the Project.

Under the Incentives Policy, an applicant must satisfy the "Statutory Test," as well as the "Nexus Test" in order to receive an incentive. The Statutory Test is met by demonstrating that the proposed transmission project either ensures reliability and/or reduces the cost of delivered power by reducing transmission congestion.[29] Currently, an applicant is presumed to meet the Statutory Test if the project is approved either: (1) through a fair and open regional planning process that evaluates projects for reliability and/or congestion; (2) by a state commission or state siting authority; or (3) if a proposed project is located in a National Interest Electric Transmission Corridor.[30] Once the applicant has satisfied the Statutory Test, it must then satisfy the Nexus Test. An applicant meets the Nexus Test if it demonstrates that there is a nexus between the incentive sought and the risks and challenges of the investment being made.

In Order No. 679, the Commission explained that the rebuttable presumption was consistent with the Commission belief that "power markets are regional in nature and that the transmission systems supporting those markets must be supported by regional planning."[31] Given the passage of Order Nos. 890 and 1000 since the issuance of the

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28 *See, e.g.*, Order No. 1000-A at n.130 (citing Order No. 1000 at P 38, which discussed a Brattle Group study "contending that a large portion of projects with an estimated total cost of over $180 billion will not be built due to overlaps and deficiencies in transmission planning and cost allocation processes.").

29 *See* 16 U.S.C. § 824s.

30 18 CFR § 35.35(i) & (j) (2019); Order No. 679 at P 58.

31 Order No. 679 at P 58.

Commission's regulations in 18 C.F.R. § 35.35(i) implementing the Order No. 679 rebuttable presumption, the Commission should, at minimum, condition the grant of the incentive on ultimate approval of the project in an open and transparent transmission planning process that complies, as applicable, with Order No. 890 or Order No. 1000. It is unreasonable to incentivize public utility transmission providers with incentive rates for projects that they are unwilling to vet with stakeholders in an open and transparent planning process.[32] For projects that are subject to a regional transmission planning region's review, the Commission should condition the grant of the incentive rates on approval by the transmission planning region.[33] This is consistent with the Commission's findings that the open and transparent regional transmission planning processes will help ensure just and reasonable rates. Specifically, as the Commission noted in Order No. 1000-A:

> Order No. 1000's regional transmission planning reforms are intended to ensure that there is an open and transparent regional transmission planning process that complies with Order No. 890's transmission planning principles and produces a regional transmission plan. There, we stated that such transmission planning will expand opportunities for more efficient and cost-effective transmission solutions for public utility transmission providers and stakeholders, which, in turn, will help ensure that the rates, terms, and conditions of Commission-jurisdictional services are just and reasonable and not unduly discriminatory or preferential.[34]

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[32] Indeed, DEMEC believes that significant transmission investments that have not been fully vetted with transmission customers, including the LSEs for which they are obligated to plan, should not receive the benefit of a presumption of prudent utility management when the public utility transmission providers seek to recover the costs in rates under Section 205 of the FPA.

[33] *See, e.g.*, *DATC Midwest Holdings, L.L.C.*, 139 FERC ¶ 61,224 at P 38 (2012) (conditioning the grant of incentives on the project being included in the regional transmission expansion plan).

[34] Order No. 1000-A at P 263.

Where a project is not subject to a transmission planning region's assessment and approval for reliability and economic needs (*e.g.*, a Supplemental Project), the Commission should presume the project ineligible for transmission incentive rates. To overcome the presumption of ineligibility, the incentive rate applicant should be required to provide a sworn demonstration: (1) that the project was or will be vetted in a process that complies with Order No. 890's transmission planning requirements and why it is not subject to review and approval in a regional transmission planning process; (2) of the reliability or economic need the project is fulfilling consistent with Section 219 of the FPA; (3) of the options available to fulfill the reliability or economic need, including with respect to transmission and non-transmission alternatives and time schedules for implementing the project; (4) that the investment is the most cost-effective and efficient option to meet the identified need; (5) of the measurable benefits to transmission customers of the investment; and (6) that the applicant agrees to limit the incentives sought to a particular cost and time estimate. Such conditions would promote the Commission's policy of ensuring open and transparent transmission planning processes, alleviate the concerns FERC Staff addressed with the inability to make a determination as to whether transmission investment that is being undertaken is the most cost effective or efficient, and facilitate establishment of just and reasonable rates.

C. The Commission Should Require Disclosure of Potential Incentive Applications and Information on Cost Estimates as Well as Encourage Cost Containment and Time Commitments for Transmission Projects Selected for Regional Cost Allocation.

The Commission should require transmission developers to announce any transmission incentives they may seek during the open and transparent transmission planning process so that the evaluation of a project in a planning process takes into account the types of transmission incentives, if any, that may apply to such requests. In addition, to permit comparison of potentially more cost-effective and efficient alternatives at the planning stage and to facilitate ensuring that consumers benefit consistent with Section 219, the Commission should require the incentive applicants to provide an initial cost estimate of the transmission investment for which they are seeking transmission incentives.[35] This will ensure a baseline for the annual information that the incentive rate applicants that have been granted incentives are required to file under FERC Form No. 730.[36] The actual costs incurred, inclusive of incentives, should also be calculated as part of the annual information requirements that the Commission should add to the FERC Form No. 730 that utilities that are granted incentives are required to file on an annual basis.

The Commission should also consider encouraging incentive rate applicants to limit their incentive request to a cost estimate and time commitment subject to the applicant submitting a filing explaining the basis for any cost overruns or delays. DEMEC understands that applicants may simply increase the cost estimate to ensure that the incentives will apply to the full expected cost of the projects. However, such measures may also facilitate the Commission's goal of incentivizing competition in regional transmission projects that are subject to regional cost allocation and Section 219's goal of benefitting consumers. That is, encouraging cost and time estimates and

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35 In the 2012 Policy Statement, the Commission stated that it expected applicants for an incentive ROE based on a project's risks and challenge to commit to limiting the application of the incentive ROE based on a project's risks and challenges to a cost estimate. 2012 Policy Statement at 28.

36 *See* 18 C.F.R. § 35.35(h) (requiring public utilities that have been granted incentive rate treatment for specific transmission projects to file annual forms on actual transmission investment for the most recent calendar year and projected incremental investments for the next five calendar years; and for projects costing $20 million or more, to also provide the expected completion date, percentage of completion, and reasons for any delays).

encouraging commitments to limit incentives to such estimates may facilitate competitive bids that can be assessed in regional transmission planning processes to ensure the most cost effective and efficient solution to a transmission need is selected.

D. The Commission Should Maintain the Requirement to Demonstrate A Nexus Between A Project's Risks and Challenges and the Total Package of Incentives Requested.

The NOI asks threshold questions on whether the Commission should retain the "risks and challenges" framework for evaluating incentive applications (NOI at P 15, Q 1); or if incentives to address risks and challenges are an appropriate proxy for the expected benefits brought by transmission and identified in Section 219 (NOI at P 15, Q 2).

The Commission should maintain the requirement for a demonstration of a nexus between the risks and challenges of a particular project and applicant and the total package of incentives requested as required in the Commission's incentive regulations.[37] Experience with a diluted risks and challenges test during the first six years of the implementation of the Incentives Policy militates against omitting this essential threshold test.[38] Specifically, in the 2012 Policy Statement, the Commission determined that it will no longer rely on the routine/non-routine test as a proxy for analyzing the need for each individual incentive and the total package of incentives.[39]

Consideration of the risks and challenges appropriately serves to ensure that projects that are routine, or that have alternative sources of funds available, are not the

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37 18 C.F.R. § 35.35(d).

38 DEMEC estimates that between 2006 and October 2011, the projected rate base for projects granted incentives rose from approximately $3.8 billion in 2006 to $63.7 billion in 2011, and the cost of ROE incentives for specific projects (not including the RTO participation adder) was $370 million per year.

39 2012 Policy Statement at P 12.

type that are granted incentives. Indeed, as the Commission stated in Order No. 679-A, the nexus test seeks to ensure that "incentives are not provided in circumstances where they do not materially affect investment decisions."[40] Maintaining the risks and challenges test also serves to facilitate the use of risk-reducing incentives and limit project-specific incentives to the truly extraordinary cases where the risk-reducing incentives are not sufficient to address the risks and challenges of a particular project. As the Commission recognized in the 2012 Policy Statement, "many risks not accounted for in the base ROE can be alleviated through risk-reducing incentives."[41] As such, omission of the requirement to demonstrate that the total package of incentives are tailored to address the risks and challenges of the project will likely harm customers by removing a necessary inquiry on what incentive or package of incentives is necessary to ensure the development of beneficial transmission that lowers costs of delivered power.[42] Such a result would lead to unjust and unreasonable rates contrary to the Section 219 mandate of benefitting consumers.[43]

In response to NOI Q 2, DEMEC notes that under the Commission's current Incentives Policy, the risks and challenges (*i.e.*, the Nexus Test) is ***not*** intended to serve as a proxy for expected benefits. Instead, the Commission has a separate test (*i.e.,* the Statutory Test), which requires demonstration by the applicant that the project: (1) ensures reliability; or (2) reduces the cost of delivered power by reducing congestion.

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[40] Order No. 679-A at P 25.

[41] 2012 Policy Statement at P 16.

[42] *See, e.g.,* Order No. 679-A at P 27 (recognizing that if the nexus test is applied separately to each incentive as opposed to the package of incentives as a whole, such an approach would "fail[] to protect consumers where an applicant seeks incentives that both reduce the risk of a project and offer an enhanced ROE for increased risk.").

[43] 16 U.S.C. 824s(d).

This test is rebuttably presumed to be met if a project results from a regional transmission planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission, a project that has received construction approval from an appropriate state commission or state siting authority, or if a proposed project is located in a National Interest Electric Transmission Corridor.[44] In this regard, the NOI does not espouse on its plans with respect to the rebuttable presumption that currently applies to the Statutory Test of whether a project ensures reliability/reduces congestion-related costs. Indeed, the NOI makes no mention of this rebuttable presumption. Nevertheless, the Statutory Test and Nexus Test are intended to address different and fundamental questions such that neither test can serve as a proxy for the other.

The NOI also posits that the Commission "could instead evaluate incentive requests based on the transmission project's potential to achieve benefits related to reliability and reductions in the cost of delivered power by reducing transmission congestion."[45] The Commission thus asks questions such as whether directly examining a transmission project's expected benefits improves the Commission's transmission incentives policy (NOI at Q 4), and if the Commission should lay out general principles and/or bright line criteria for evaluating potential benefits of a proposed transmission project (NOI at Q 5).

In response to Q 4 and Q 5, DEMEC notes that Order No. 1000 already requires transmission planning regions to consider benefits of regional transmission projects that will be subject to regional cost allocation. Specifically, Order No. 1000 required regional

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[44] 18 C.F.R. § 35.35(i) & (j); Order No. 679 at P 58.

[45] NOI at P 16.

and interregional cost allocation methods to adhere to six cost allocation principles, including that the costs must be allocated in a way that is roughly commensurate with benefits and that there must be a transparent method of identifying benefits and beneficiaries.[46] Order No. 1000 also left it up to the transmission planning regions to determine the manner of determining beneficiaries and allocating costs.[47] The Commission stated that public utility transmission providers in each region are to "be definite about benefits and beneficiaries."[48] As such, while the expected benefits of a project are pertinent to a consideration of whether incentive rates should be provided, projects that are selected through a regional transmission planning process for regional cost allocation will already have conducted analysis on the projected benefits of regional transmission investment. While the Commission declined to require applicants to provide cost-benefit analyses in Order No. 679, the Commission found that regional planning can help determine whether a given project is needed and is the most cost-effective option in light of other alternatives.[49] DEMEC thus submits that conditioning incentive rate requests to projects having been vetted and approved in regional

[46] *See, e.g.*, Order No. 1000-A at P 91 ("Order No. 1000 requires that the costs of facilities selected in a regional transmission plan for purpose of cost allocation be allocated in a way that is roughly commensurate with benefits, i.e., allocated in accordance with the requirements of cost causation."). *See also, e.g.*, Order No. 1000-A at P 524; citing Order No. 1000 at PP 622-93 (stating the six allocation principles, which include the commensuration of cost allocation with benefits and the transparent determination of benefits).

[47] *See* Order No. 1000-A at P 647 (affirming Order No. 1000's requirement that public utility transmission providers develop regional and interregional cost allocation methods based on the six cost allocation principles that "best suit regional needs" in consultation with stakeholders and noting "[i]t would be inconsistent with the regional flexibility provided in Order No. 1000 for the Commission to prescribe a uniform approach to determining benefit or beneficiaries when a multitude of factors vary across transmission planning regions and the entire country."). *See also id.* at P 648 (The requirement for regions to develop cost allocation methods "does not amount to a delegation of Commission authority because the Commission ultimately will determine whether the method or methods are just and reasonable and interested parties will continue to have an opportunity to support or oppose the cost allocation methods proposed in the compliance filings.").

[48] *Id.* at P 679.

[49] Order No. 679 at P 58.

transmission planning processes is an efficient way to ensure that the projects seeking incentive rates will provide expected benefits consistent with Section 219 and to presume ineligible those projects that are not approved by transmission planning regions unless certain additional demonstrations are made. But assessing a project's expected benefits does not obviate the need to determine the appropriate package of incentives that should be granted to a particular applicant.

With respect to Q 6 of the NOI on whether a direct evaluation of expected benefits would impact certainty for project developers, relying on the Order No. 1000 regional planning processes would enhance as oppose to adversely impact certainty for project developers since they will know that their transmission investment has been approved by a regional transmission planning body. However, with respect to the question in Q 6 of the NOI assumption on use of risks and challenges as a proxy for expected benefits, and with respect to Q 8's question on whether levels of incentives should vary based on the expected benefits, DEMEC emphasizes that evidence of benefits is a required, but not a sufficient test to determine the appropriate package of incentives, if any, that should be provided to an incentive rate applicant.[50] As such, even if the Commission conditions incentive rate eligibility to projects that are planned in Order No. 1000-compliant regional transmission planning processes, that does not replace the pertinent demonstration that an incentive rate applicant should be required to make on whether the total package of incentives is tailored to address the risks and

[50] *See, e.g.*, *Dairyland Power Coop.*, 142 FERC ¶ 61,100 at P 30 (2013) (stating that the Commission has approved multiple rate incentives for particular projects as long as each incentive satisfies the nexus test as "[t]his is consistent with our interpretation of section 219 authorizing the Commission to approve more than one incentive rate treatment for an applicant proposing a new transmission project, as long as each incentive is justified by a showing that it satisfies the requirements of section 219 and that there is a nexus between the incentives proposed and the investment made.").

challenges of the project. Without a demonstration of risks and challenges it will be difficult for the Commission to assess which particular incentive should be awarded to the incentive rate applicant so as to ensure just and reasonable rates.

E. When Incentives are Warranted, the Commission Should Retain its Current Approach of Focusing on Risk-Reducing Incentives over Return-Enhancing Incentives.

In the 2012 Policy Statement, the Commission reaffirmed its Order No. 679 policy that risk-reducing incentives such as the CWIP Incentive, Abandoned Plant Incentive, and Pre-commercial Incentive – reduce the financial and regulatory risks associated with transmission investment and may mitigate risks not accounted for in the base ROE.[51] The 2012 Policy Statement thus expected incentive applicants to first examine the use of risk-reducing incentives before seeking an incentive ROE based on a project's risks and challenges.[52] The 2012 Policy Statement also provided that an applicant seeking a project-specific ROE adder is expected to demonstrate: (1) the project risks/challenges are not already addressed in the base ROE or through risk-reducing incentives; (2) use of risk mitigation steps during project development; (3) consideration of project alternatives; and (4) a commitment to limit the ROE incentive application to a cost estimate.[53]

In this NOI, the Commission notes that the Commission has required applicants to seek to employ risk reducing incentives before they seek an ROE adder for risks and challenges,[54] but seeks instead to determine the interaction between different potential

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[51] 2012 Policy Statement at P 11.

[52] *Id.*

[53] *Id.* at PP 20-28.

[54] NOI at n. 57. *See also id.* at P 17 & n.27 (where the NOI notes that in examining whether and how the Commission might consider benefits relative to costs when evaluating a request for incentives, Order

incentives in determining the "correct level" of ROE incentives.[55] Specifically, the Commission asks what level or combination of transmission incentives should be provided or how to ensure that the combination of incentives provided is appropriate to produce rates that are just and reasonable. (NOI at P 46, Q 93-94).

As discussed in Section III.D above, retaining the Nexus Test is essential to facilitating the Commission's review of the correct combination and level of transmission incentives. In addition, the Commission should continue to require incentive rate applicants to rely on risk-reducing incentives and to require the four additional demonstrations from the 2012 Policy Statement noted above for the grant of any project-specific ROE adders. Transmission investment has increased, including under the time period when the 2012 Policy Statement has been in effect.[56] There is no evidentiary basis to conclude that there is a need to provide ROE adders on top of risk-reducing incentives to incentivize development of projects to ensure reliability or reduce the cost of congestion. To grant any level of ROE adder for a project when risk-reducing incentives and the base ROE would suffice to address risks and challenges of developing the project, would result in an unnecessary bonus at the expense of consumers that Section 219 intended to benefit.

In addition, as discussed in Section III.G below, the Commission should certainly refrain from granting incentives (particularly ROE adders) for projects with characteristics that are of the type that the public utility transmission providers are

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No. 679 rejected limiting an incentive award on specific level of benefits, except that it limited ROE adders for risks and challenges to a cost estimate and a demonstration of the use of risk reduction techniques).

[55] NOI at Section II.D.3.

[56] Edison Electric Institute Historical and Projected Transmission Investment (Nominal Dollars) (updated Oct. 2018).

required to develop as part of their core utility service obligation. In fact, the Commission should refrain from addressing incentives based on project characteristics or incentive objectives or use project characteristics as a proxy for expected benefits as contemplated in PP 18 and 20 of the NOI, as they may change over time and be very fact and region-specific. Instead, a general policy of relying on risk-reducing incentives and requiring additional demonstrations before granting any project-specific ROE adder will facilitate ensuring a uniform approach to the Commission's Incentives Policy that reduces uncertainty for transmission developers and protects consumers from unjust and unreasonable rates. To the extent a project-specific ROE adder is deemed needed after exhausting all risk-reducing incentives, in response to Q 8-10 of the NOI, the Commission should limit the incentive to a reasonable and verifiable cost estimate as is currently required and ensure a measurable relationship between the total costs (inclusive of all types of incentives) and benefits of the project.

F. A Case-by-Case Review is Essential to Ensuring Just and Reasonable Rates and the Commission Should Not Grant Incentive Rates on an Automatic Basis.

The NOI asks at least seven separate questions on whether the Commission should grant certain incentives automatically instead of engaging in a case-by-case review, including if the Commission should rebuttably presume that risk-reducing incentives should be pre-approved for projects that undergo a regional transmission planning process. NOI at Q 7, 52, 53, 70, 77, 90-92. Among the questions in this regard are whether the grant of automatic incentives would provide additional certainty presumably to transmission developers. NOI at Q 90. However, there has been no showing that there is a need to provide transmission developers with "additional certainty" in order to ensure development of needed transmission. The Commission's current Incentives Policy, which has provided a rebuttable presumption to facilitate demonstration of project benefits, and which has provided ample body of precedent on the showings required to obtain risk-reducing incentives, and if necessary, return enhancing incentives, provides sufficient certainty to incentivize development of needed transmission.[57]

In addition, pre-approving or granting incentives on an automatic basis, even for projects that have undergone an Order No. 1000 regional transmission planning process, would be contrary to FPA Section 219's purpose of benefitting consumers for several reasons. A primary reason for not abandoning the case-specific approach to the Incentives Policy is that not all transmission projects, including transmission projects approved under a regional transmission expansion process, warrant incentives based on the routine nature of the project or the relative risks or challenges faced by the applicant.[58]

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[57] *See e.g., Startrans IO, L.L.C.*, 130 FERC ¶ 61,209 at P 29 (2010) ("The Commission will determine whether a particular applicant meets these criteria on a case-specific basis, because that determination will be based on the specific facts before it in individual proceedings. We decline to establish a bright-line rule, beyond the criteria established in Order No. 679, in what is necessarily a fact-specific analysis. Moreover, the Commission has longstanding precedent regarding acquisition adjustments for ratemaking purposes, some of which is cited in this order.").

[58] *See, e.g., Commonwealth Edison Co. & Commonwealth Edison Co. of Indiana, Inc.*, 124 FERC ¶ 61,231 at P 18 (2008) (finding that while "'PJM's scrutiny of baseline projects is *significant* in our analysis of whether a project has met the nexus test,"' this "does not mean that all baseline projects in PJM's RTEP will qualify automatically for incentives under Order No. 679," and stating the Commission also examines factors such as "the scope of the project, its effect on the transmission system, and other challenges or risks faced by the project.") (emphasis in original); *Pacific Gas & Elec. Co.*, 160 FERC ¶ 61,018 (2017) (denying the Abandoned Plant Incentive for certain projects because they either presented limited, speculative or modest risks or challenges, and one project largely involved upgrades and extensions of existing facilities); *ATX Southwest, L.L.C.*, 152 FERC ¶ 61,193 at P 48 (2015) (finding that the applicant had not met the nexus test under Order No. 679 in part because it failed to describe details of its financial situation that the CWIP Incentive would alleviate, including details regarding its financial pressures, delayed cash flow, relative size of its investment, any adverse impacts to short-term liquidity, or the size of the effect on cash flow that CWIP would elicit).

Moreover, to the extent that the incentives would be deemed approved without the sixty day notice requirement for rate changes under Section 205 of the FPA, the automatic grant of incentives would violate the requirement in Section 219 that all rates be subject to the requirements of section 205 of the FPA.[59] Pre-approval or automatic approval would also result in the Commission essentially delegating to jurisdictional utilities its obligation to ensure the justness and reasonableness of jurisdictional rates.[60] Furthermore, pre-approval or automatic approval would create an unreasonable shift of the burden of proof to transmission customers, as they would then have to demonstrate, potentially with a less robust record, that the incentive rates are not warranted under the circumstances and are unjust, unreasonable or imprudent.[61] As such, it would be inconsistent with FPA Section 219 and the consumer benefit protections of the FPA, for the Commission to provide a pre-approval or automatic grant of any incentives to transmission projects, even if approved in a regional transmission planning process.[62]

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[59] 16 U.S.C. § 824d(d) (requiring sixty days' notice to the Commission and to the public of any change in rates or charges).

[60] *Entergy Services, Inc.*, 120 FERC ¶ 61,020 at P 28 (2007) (denying the utility's request for a Commission determination that the purchase of a facility is prudent and that all costs of the transaction may be included in formula rates in part on the grounds that "the Commission cannot delegate to jurisdictional utilities it obligation to ensure the justness and reasonableness of jurisdictional rates.").

[61] The structure of the Federal Power Act and implementing Commission regulations place the burden on public utilities to demonstrate that the rates they propose are just and reasonable. 16 U.S.C. § 824d(e); 18 C.F.R. §§ 35.12 and 35.13 (2019).

[62] *Pub. Sys. v. FERC*, 606 F.2d 973, 979, n. 27 (D.C. Cir. 1979) ("[T]he Federal Power Act aim[s] to protect consumers from exorbitant prices and unfair business practices. This purpose can be seen in the statutory requirement that rates be just, reasonable, and nondiscriminatory."); *Xcel Energy Services Inc. v. FERC*, 815 F.3d 947, 952-53 (D.C. Cir. 2016) (quoting *Mun. Light Bds. of Reading & Wakefield v. Fed. Power Comm'n*, 450 F.2d 1341, 1348 (D.C. Cir. 1971), cert. denied, 405 U.S. 989 (1972)) ("It is long-established that the 'primary aim [of the FPA] is the protection of consumers from excessive rates and charges.'").

G. Projects Undertaken as Part of a Utility's Core Business Purposes or Obligations Should Not Ordinarily be Provided Incentives.

The NOI includes questions on whether incentives are warranted for transmission projects with: (1) flexible characteristics (*e.g.*, increased line rating precision, greater power flow control, and technologies, including energy storage) (NOI at P 26, Q 30); (2) physical security and cybersecurity enhancements (NOI at P 27, Q 32); (3) resiliency enhancements (NOI at P 28, Q 34); or (4) improvements to existing facilities (NOI at P 29, Q 37-42). While DEMEC understands the need to invest in technologies, physical and cybersecurity, and resiliency-based projects, the Commission should recognize that a transmission provider's compliance with the NERC Reliability Standards does not merit a separate incentive. On the contrary, under Section 215(e) of the FPA, a transmission provider must comply with its applicable NERC Reliability Standards or face a penalty for any violation of a Reliability Standard.[63] The Commission has long recognized that denying incentive rate treatment to utilities for undertaking what they are already obligated to do is in the public interest.[64] Consistent with Commission policy and long-standing precedent, there should not be a specific incentive reward for transmission providers that are merely complying with their statutory obligations to provide safe and reliable utility service.[65]

H. The Commission Should Revise the Manner in Which It Incentivizes RTO/ISO Participation.

Section 219(c) of the FPA provides, in pertinent part, that "the Commission shall, to the extent within its jurisdiction, provide for incentives to each transmitting utility or

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[63] 16 U.S.C. § 824o(b)(1), (e)(1).

[64] *See e.g.*, *New England Power Pool*, 97 FERC ¶ 61,093, at 61,477 (2001) ("This decision is in the public's interest as it does not unjustly reward NEP for doing what it is supposed to do.").

[65] *Id.*

electric utility that joins a Transmission Organization,"[66] provided it results in a just and reasonable rate.[67] Pursuant to Order No. 679, the Commission determined it would "approve, *when justified*, requests for ROE-based incentives for public utilities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization."[68] The Commission clarified that this incentive would apply to utilities that "have already joined and that remain members" and for "continuing membership" in a Transmission Organization, in "recognition of the benefits that flow from membership" and the fact that "continuing membership is generally voluntary."[69] In practice, the Commission has routinely granted a 50 basis point adder to a public utility transmission provider's base ROE for joining and remaining a member of an RTO/ISO. This RTO/ISO adder, which has essentially become a generic adder, is routinely applied to the entire rate base of a public utility transmission provider's annual transmission revenue requirement.

The NOI recognizes that the United States Court of Appeals for the Ninth Circuit ruled in favor of the California Public Utilities Commission's petition for review, finding that the Commission's application of the RTO/ISO adder for PG&E's participation in the California Independent System Operator Corporation ("CAISO") departed from long-standing policy of granting incentives only where necessary to induce future behavior, not reward past behavior that was undertaken irrespective of the incentive.[70] The NOI asks various questions regarding the RTO/ISO participation incentive (NOI at P 38, Q

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[66] 16 U.S.C. § 824s(c).

[67] 16 U.S.C. § 824s(d).

[68] Order No. 679 at P 326 (emphasis added).

[69] *Id.* at PP 326, 331.

[70] NOI at P 38; *California Pub. Utilities Comm'n v. FERC*, 879 F.3d 966 (2018).

61-66), including whether it should revise the current RTO/ISO participation incentive (NOI at Q 61), if it should be provided for a fixed period of time (not to exceed ten years) after a transmission owner joins an RTO/ISO (NOI at Q 64), and if voluntary participation should remain a requirement for receiving RTO/ISO incentives. (NOI at Q 66).

In response to Q 61, DEMEC recommends the Commission consider eliminating the ROE adder for RTO/ISO membership in favor of a more reasonable incentive to satisfy Section 219(c)'s requirement to incentivize RTO/ISO participation but it should do so on a case-specific basis as opposed to an automatic grant of any incentive. In this regard, in response to Q 62, DEMEC recommends that the Commission should not automatically grant the CWIP Incentive, Abandoned Plant Incentive, or any other incentive to utilities participating in RTOs/ISOs but could consider the CWIP Incentive in lieu of the ROE adder to incentivize RTO/ISO participation on a case-specific basis. When CWIP Incentive is allowed, the Commission should make sure that the utility does not recover any AFUDC or ADIT associated with the CWIP. In response to Q 66, the RTO/ISO participation adder should only apply to reward voluntary action and should not be available to a public utility transmission provider that has a legal obligation (e.g., a state law, contract, settlement agreement, or merger condition) to join or remain a member of an RTO/ISO.

In response to Q 61, 63 and 64, DEMEC recommends that if the Commission retains an ROE adder to incentivize voluntary RTO/ISO participation, the Commission should evaluate the appropriate level, if any, of this RTO/ISO participation adder on a case-specific basis. Such case-specific evaluation may include factors such as whether the ROE adder should apply to the entire rate base or just to specific projects that were selected in a competitive regional transmission planning process, and/or whether the public utility transmission provider is adhering to the transmission planning requirements of Order Nos. 890 and 1000, and/or whether the Commission has already approved other transmission rate incentives for that facility.

DEMEC submits that it would be contrary to Section 219's purpose of benefitting consumers or to cost causation principles to provide RTO/ISO participation ROE adders to the entire transmission rate base of public utility transmission providers that are planning more than 50 percent of their annual transmission investment without fully vetting the investments in open and transparent transmission planning processes available (or that could be made available) through the RTO/ISO in which they participate. In this regard, it is important to bear in mind that under an Order Nos. 890 and 1000 regime, even public utility transmission providers in non-RTO/ISO regions are required to conduct open and transparent planning processes and that these transmission planning regions also consider reliability and economic needs,[71] consistent with the purpose of Section 219.[72] As such, the RTO/ISO participation incentive should be, at minimum, limited to those projects of a public utility transmission provider that were subject of full vetting in an open and transparent planning processes provided by the RTO/ISO. In this

71 *See* J. Eto & G. Gallo, "Regional Transmission Planning: A Review of Practices Following FERC Order Nos. 890 and 1000," Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory (Nov. 2017) at vi-vii (noting that for both non-ISO/RTO regions and ISO/RTO regions the transmission planning activities and "regional transmission needs are driven either by requirements to maintain the reliability of the grid, by public policy requirements, or by economic considerations."). *See also id.* at viii (noting transmission needs driven by economics are "needs associated with reducing congestion costs or integrating efficient new resources and new or growing loads.").

72 *See* Order No. 679-A at P 86 (finding that Section 219 was intended to provide incentive-based rate treatments that benefit consumers by ensuring reliability and reducing the cost of delivered power and that "an inducement for utilities to join, and remain in, Transmission Organizations [is] entirely consistent with those purposes.").

regard, capital expenditures that were merely rolled up to the regional transmission expansion plan (*e.g.*, such as the Supplemental Projects in PJM or other self-approved capital expenditures) or otherwise not reviewed in the RTO/ISO's planning process, would not qualify for the RTO/ISO participation adder. The RTO/ISO participation adder should also be subject to the zone of reasonableness.

In response to Q 64, if the Commission retains the ROE adder for RTO/ISO participation, it should apply a presumption that the ROE adder if deemed appropriate to grant on a case-specific basis (whether for a particular project(s) or entire rate base) and subject to the upper end of the zone of reasonable returns, would be phased out after the utility has maintained its membership for a certain number of years. Phasing out the RTO/ISO participation adder would balance the interests of incentivizing participation in RTOs/ISOs as Section 219 intended while also recognizing that FERC-jurisdictional transmission providers receive base ROEs that are sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[73] Under a phase out approach, if the Commission grants a 50 basis point incentive adder for RTO/ISO membership when a utility joins an RTO/ISO, it would do so only for a defined number of years subject to the upper end of the zone of reasonableness returns. After that defined period, the RTO/ISO incentive ROE adder would be presumed to be phased down and then out (*e.g.*, reduced from 50 basis points to 40 basis points at a set interval, and then continued to drop on a set interval basis until it reaches 0 basis points). A phase out approach would further Section 219's objectives of benefitting consumers and ensuring just and reasonable rates. Each utility would have the

[73] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

opportunity to provide its rational for its proposed RTO/ISO incentive, and the Commission would be able to consider both the utility's reasoning and consumer responses on a case-by-case basis.

I. Responses to Various Other Specific Questions.

1. Non-Public Utilities.

The NOI at Q 51 inquires if the Commission should consider granting incentives to promote joint ownership arrangements with non-public utilities and if so, how. DEMEC supports encouraging public utilities to engage in joint ownership of transmission with non-public utilities. It should do so by requiring public utility incentive rate applicants to explain if they considered partnering with a non-public utility transmission provider's bid for the project.

2. Interregional Transmission Projects.

The NOI inquires whether incentives should be granted to encourage the development of interregional transmission projects. (NOI at P 30, Q 44). The lack of interregional transmission facilities, by itself, does not necessarily suggest that there is a particular risk or challenge associated with the interregional project, or that there is a particular benefit to the consumers. Accordingly, the status of a transmission project as an interregional project alone does not merit the grant of incentives and, absent other compelling circumstances, the Commission should refrain from incentivizing investment that may not be needed, or that would be developed in the absence of incentives.

3. Unlocking Locationally Constrained Resources.

In Q 47 of the NOI, the Commission asks if it should use incentives to encourage the development of transmission projects that will facilitate the interconnection of large amounts of resources. (NOI at P 31, Q 47). The 2012 Policy Statement found that "projects that unlock location constrained generation resources that previously had limited or not access to the wholesale electricity markets" may be eligible for incentives.[74] DEMEC notes two issues with this approach. First, DEMEC is concerned that awarding such incentives implicates the need for incentives where a transmission provider *voluntarily* agrees to fund network upgrades that interconnection customers would be required to fund. The Commission should refrain from granting incentives to a transmission provider that voluntarily agrees to fund network upgrades, which would ultimately require interconnection customers to fund. To do so would contradict the essential principle of transmission incentive rates since an incentive cannot "induce" behavior that has been previously agreed to voluntarily.[75] Second, this approach also raises concerns with whether to presume eligibility for incentives, particularly return-enhancing adders, for network upgrades and whether such projects must meet independent case-specific demonstrations to receive risk-reducing incentives. If a particular region has sufficient, lower-cost alternatives to meet its resource needs, there should be no need to provide special incentives just because the project interconnects a location-constrained resource.

4. Order No. 1000 Transmission Projects.

The NOI at Q 54 inquires if the Commission should continue to use certain incentives to seek to place non-incumbent transmission developers on a level playing field with incumbent owners in Order No. 1000 regional transmission planning processes under Section 205 of the FPA. The purpose of granting incentives for non-incumbent

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[74] NOI at P 21.

[75] *San Diego Gas & Elec. Co.*, 154 FERC ¶ 61,158 at P 19, citing Order No. 679, at PP 6, 48 (The Commission must find that the incentive will "encourage transmission investment that may not otherwise occur.").

transmissions owners is to place them on a level playing field with incumbent transmission owners in Order No. 1000 regional transmission planning processes.[76]

This inquiry raises the issue of whether use of Section 205 would circumvent the rules established in an incentive policy to award incentives to utilities that do not meet the Commission's criteria for incentives. In this regard, the Commission should refrain from undermining the transmission planning process, including any cost containment considerations, during the selection of the non-incumbent's project. Additionally, the Commission should not award a special incentive simply because a non-incumbent transmission owner is developing the project. The Commission should require the applicant to meet the Section 219(a) Statutory Test threshold demonstrations for non-incumbent projects as well as the Nexus Test.

5. Abandoned Plant Incentive.

In NOI Q 77-79, the Commission asks various questions regarding the Abandoned Plant Incentive. DEMEC submits that in accordance with Commission policy and precedent, the Commission should continue to limit the grant of the Abandoned Plant Incentive to those prudently-incurred project costs expended on or after the issuance of the order granting the incentive.[77] The Commission has consistently found, and the United States Court of Appeals for the D.C. Circuit has recently affirmed,[78] that incentives should not be granted for actions that have already been undertaken. Granting such incentive prior to its approval would "be contrary to the

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[76] NOI at P 34, Q 54.

[77] *DCR Transmission, L.L.C.*, 153 FERC ¶ 61,295 at P 42 (2015) ("[A]bandoned plant recovery is available for 100 percent of prudently-incurred project costs expended on or after the issuance of this order."); *accord PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,156 at P 54 (2013); *PJM Interconnection, L.L.C.*, 140 FERC ¶ 61,197 at P 24 (2012).

[78] *San Diego Gas & Elec. Co. v. FERC*, 913 F.3d 127 (2019).

general policy rationale that incentives are designed to encourage *future* transmission investments."[79] Similarly, consistent with long-standing Commission precedent, the Commission should continue to limit and/or remove incentives once a transmission project has been abandoned.[80]

6. Yet-to-be Formed Affiliates.

In NOI Q 74, the Commission asks if it should grant the hypothetical capital structure incentive to an entity's yet-to-be-formed affiliates. The Commission has previously granted applicants the ability to permit yet-to-be-formed affiliates to utilize the applicant's formula rate, including ROE, and transmission rate incentives.[81] The Commission should refrain from permitting yet-to-be-formed utilities from using the current applicant's formula rate, ROE, and incentive rate treatments. It is unreasonable to shift to transmission customers the risk of bearing the incentive-based cost as well as the burden of proof to defend against use of such formula rates and incentives. Such action also causes an improper shift of the burden of proof away from the yet-to-be-formed

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[79] *San Diego Gas & Elec. Co.*, 154 FERC ¶ 61,158 at P 20 (2016) (emphasis provided).

[80] *See e.g., PJM Interconnection, et al.,* 142 FERC ¶ 61,156 at P 44 (Feb. 28, 2013) ("We find that the 150 basis point incentive adder granted to the PHI Companies for the risks and challenges in bringing the MAPP Project into service is no longer warranted. While granting a ROE incentive adder is intended to facilitate investment in the project and encourage the construction of transmission facilities, the Commission did not intend for this incentive to apply once the project is abandoned.").

[81] *See, e.g., PJM Interconnection, L.L.C. and Northeast Transmission Dev., L.L.C.*, 155 FERC ¶ 61,097 (2016) *order on reh'g*, 158 FERC ¶ 61,060 at PP 20-22 (2017) (affirming prior order granting yet-to-be-formed affiliates or subsidiaries to replicate the proposed formula rate, but clarifying that "an affiliate or subsidiary must demonstrate in its section 205 filing that it is similarly situated" to the original applicant); *PJM Interconnection, L.L.C. NextEra Energy Transmission MidAtlantic, L.L.C.*, 164 FERC ¶ 61,185 at P 20 (2018) (granting yet-to-be-formed affiliates or subsidiaries to replicate the proposed formula rate and incentives); *Transource Kansas, L.L.C.*, 154 FERC ¶ 61,011 at PP 17-18 (2016), *petition for review denied sub nom. for lack of standing*, *Kansas Corp. Comm'n v. FERC*, 881 F.3d 924 (D.C. Cir. 2018); *DesertLink, L.L.C.* , 161 FERC ¶ 61,126 at PP 39-40 (2017), *order denying motion to vacate*, 165 FERC ¶ 61,076 at P 9 (2018) (granting yet-to-be-formed affiliates or subsidiaries to replicate the proposed formula rate and certain incentives to facilitate the formation of additional entities for purposes of participating as nonincumbent transmission developers in Order No. 1000 competitive transmission processes but parties subsequently reached settlement revising the formula rate to provide that absent a FPA Section 205 filing, the formula rate cannot be used by any entity (including affiliates or subsidiaries of the applicant).

affiliates under FPA Section 205 to transmission customers. In response to DEMEC's rehearing request in one such case, the Commission clarified that the yet-to-be-formed affiliate must demonstrate in its Section 205 filing that it is similarly situated to the parent company as to warrant use of the non-incumbents approved formula rate and incentives. At minimum, any grant of use of an applicant's formula rate, ROE and incentives should be subject to the same clarifications and limitations as in the NTD case.[82]

J. Mechanics and Implementation of Incentives.

In Q 83-89 of the NOI, the Commission asks various questions pertaining to the duration of transmission incentives. As noted in Section III.H above, the Commission should limit the duration of the RTO/ISO participation adder. The Commission should also limit the duration of other ROE adders, such as requiring the project-specific ROE adder to sunset once a project has been placed in service.

The NOI also seeks to explore whether the Commission should require the submission of additional information in the Form (*e.g.*, primary driver for the transmission project, risks entailed such as siting challenges, and reasons underlying project failure). (NOI at P 48, Q 98-105). The Commission should expand the reporting requirements to permit FERC Staff and interested parties the ability to determine the cost-benefits of the project and to determine if cost-effective and efficient transmission is being developed.

[82] *PJM Interconnection, L.L.C. & Northeast Transmission Dev., L.L.C.*, 158 FERC ¶ 61,060 at PP 20-22.

V. CONCLUSION

WHEREFORE, DEMEC respectfully requests that the Commission consider these comments and the positions and recommendations made herein.

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Respectfully submitted,

/s/ Thomas L. Rudebusch
Thomas L. Rudebusch
Adriana Vélez-León

Duncan, Weinberg, Genzer
& Pembroke, P.C.
1667 K Street, N.W., Suite 700
Washington, D.C. 20006
(202) 467-6370
tlr@dwgp.com
avl@dwgp.com

Attorneys for the
Delaware Municipal Electric Corporation, Inc.