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nationalgrid

June 26, 2019

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

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

Dear Secretary Bose:

Please find enclosed for electronic filing the "Comments of National Grid USA" in the above referenced Commission docket. Please do not hesitate to contact me if you have any questions or concerns.

Respectfully submitted,

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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
NATIONAL GRID USA

Pursuant to the Federal Energy Regulatory Commission's ("Commission" or "FERC") March 21, 2019 Notice of Inquiry in this proceeding,[1] National Grid USA ("National Grid") submits these comments on behalf of its electric transmission subsidiaries in New England and New York.

I. BACKGROUND

In the Notice of Inquiry, the Commission seeks comment on the scope and implementation of its electric transmission incentives regulations and policy. Specifically, the Commission presents a series of questions regarding the Commission's transmission incentives policy and encourages commenters to provide detailed responses to the questions and provide specific examples to support comments and recommendations where appropriate. In these Comments, National Grid provides its views and positions on these questions to assist the Commission in its consideration of this matter.

The electric industry is amid unprecedented change, driven by increases in renewable generation, rapid advances in technologies, and the need to respond to threats to the reliability and resilience of the electric system. While the names of devices and the types of fuel may be different,

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

the need for infrastructure investment and recovery of costs is a constant. Balancing these evolving interests requires a clear and predictable policy that is adaptable to a changing landscape.

The need for incentives is as important today as it was nearly a decade and a half ago when Congress directed the Commission to implement its incentives policy. In Order No. 679, the Commission determined that abundant evidence supported the need for new transmission investment and justified the creation of new incentives, "including the fact that transmission investment in real dollars terms is lower today than it was in 1975 when the load was significantly smaller and that, even with the transmission additions of recent years, the industry still incurs significant congestion costs due to inadequate transmission."[2] Today, the electric sector faces a similar need to expand transmission infrastructure, albeit driven by different factors. Looking forward, transmission expansion will be critical to meeting a variety of needs, including the growing use of location-constrained renewables and other low-carbon resources, electrification of the transport and heating sectors of the economy, and ensuring resilience of the electric system.

Continued development of renewable generation will drive significant expansions of the transmission system. Nationally, EIA, in its 2019 Annual Energy Outlook, projects renewable generation to increase by more than 130% through the end of 2050, reaching nearly 1,700 billion kilowatthours (BkWh).[3] Roughly 90% of the growth in renewables generation over this period will be accounted for by increases in wind and solar development, much of which will require transmission to deliver the output from these resources. In recognition of the trends shaping the electric industry, National Grid is currently planning the future of its transmission network in New

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[2] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) (Order No. 679) at P 14.

[3] U.S. Energy Information Administration, *Annual Energy Outlook 2019*, January 24, 2019 (https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf), at p.102.

England and New York to provide reliable, low-cost electricity for customers while meeting policy and climate goals. Within National Grid's service territories, New England and New York will require new and upgraded transmission networks to integrate the most cost-effective, large-scale renewable energy projects. Many projects are, or will be, located at remote or constrained points on the transmission network in Maine, upstate New York, and offshore. Meeting our states' ambitious clean energy goals cost-effectively will also require tapping into affordable renewable resources located outside of New England and New York via new transmission.

Electrification of sectors of the American economy will significantly increase demand for electricity and drive the need for transmission expansion. The combination of concerns about the effects of fossil fuel consumption and the development of attractive low-carbon technologies will allow consumers to fuel cars and heat homes using electricity; businesses will be able to provide process heat at industrial facilities. Change is most pronounced in the transportation sector, where evidence of this transition is already observable. The Edison Electric Institute projects that the US will add the next million electric vehicles (EVs) by 2021; with nearly 19 million projected to be added by 2030.[4] To meet increases in demand that result from electrification, low-carbon electricity generation resources will be built and supported by robust transmission and distribution infrastructure. A recent report by the Brattle Group finds that "$30–90 billion dollars of incremental transmission investments will be necessary in the U.S. by 2030 to meet the changing needs of the system due to electrification, with an additional $200–600 billion needed from 2030 to 2050."[5]

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[4] See Edison Electric Institute, The Edison Foundation, Institute for Electric Innovation report, *Electric Vehicle Sales Forecast and the Charging Infrastructure Required Through 2030*, November 2018, (https://www.edisonfoundation.net/iei/publications/Documents/IEI_EEI%20EV%20Forecast%20Report_Nov2018.pdf).

[5] Brattle Group, *The Coming Electrification of the North American Economy*, (https://wiresgroup.com/new/wp-content/uploads/2019/03/Electrification_BrattleReport_WIRES_FINAL_03062019.pdf) February 28, 2019, at ii, 17.

As the Commission continues to emphasize the need to maintain and enhance the resilience of the electric system, it will be critical to focus on the contributions of electric transmission infrastructure. Threats to electric system resilience can take many forms, including severe weather and physical and cybersecurity attacks. Resilience can be compromised by attacks; as Chairman Chatterjee recently noted, the nation's "critical infrastructure is increasingly under attack" and relevant government agencies (e.g., the Department of Homeland Security) have "issued multiple public reports" describing cyber-intrusion campaigns against our critical infrastructure, including the electric grid.[6] Many of the same concerns highlighted by the Commission – and by the 2005 Energy Policy Act – drive National Grid's transmission investments, including focus on flexibility and resiliency.

Severe weather can also adversely affect system resilience, which system operators have recognized and are addressing. In one case, Argonne National Laboratory has helped ISO New England, Inc. ("ISO-NE") prepare for winter storms by providing an analysis of the potential effects such a storm could have on the New England power system.[7] Nevertheless, the transmission system provides effective defense against threats to resilience through "the diversification of resources and multiple pathways for two way power flow to and from

[6] Written Testimony of Neil Chatterjee, Chairman, Federal Energy Regulatory Commission, Before the Subcommittee on Energy Committee on Energy and Commerce United States House of Representatives, June 12, 2019.
https://energycommerce.house.gov/sites/democrats.energycommerce.house.gov/files/documents/Chatterjee%20-%20Testimony%20of%20Neil%20Chatterjee%20for%20House%20Hearing%206.12.19.pdf

[7] *See*, ISO Newswire, December 12, 2018, *Argonne National Laboratory helps ISO-NE system operators prepare for impacts of major winter storm.*
http://isonewswire.com/updates/2018/12/12/argonne-national-laboratory-helps-iso-ne-system-operators-pr.html

distribution systems and customers."[8] As such, any response to these growing threats must include transmission solutions.

II. SUMMARY

The Commission was charged with establishing incentives with the goal of benefitting consumers through increased reliability and lower costs of power.[9] Those interests deserve continued support and promotion. Congress and the Commission also recognized that incentives could encourage technology which would, in turn, enhance capacity, efficiency, and reliability and that there was, therefore, a need to encourage new investment in transmission.[10] Those interests are even stronger today than they were when the Commission's current incentives policies were established.

This NOI provides the Commission with an opportunity to develop an incentives policy that recognizes the development of new technology, the new ways that energy is generated and delivered, and the need for investment and certainty in cost recovery. Any incentives policy must promote reliability and economic efficiency but also provide applicants and the Commission with flexibility to consider incentives in an evolving world. National Grid encourages the Commission to develop the next iteration of its incentives policy with these considerations in mind and seeks to answer the Commission's specific questions below in a way that is consistent with these goals.

The Commission has organized its NOI with four major headings: Approach to Incentive Policy, Incentive Objectives, Existing Incentives, and Mechanics and Implementation. In this

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[8] The Brattle Group, *Recognizing the Role of Transmission in Electric System Resilience*, May 9, 2018, at p. 3, filed in AD18-7-000.

[9] *California Pub. Utilities Comm'n v. FERC*, 879 F.3d 966, 970 (9th Cir. 2018).

[10] 16 U.S.C. §824s(b)(2), (3).

section, National Grid summarizes its responses to the questions found under those headings. Regarding Approach to Incentives, National Grid strongly supports the Commission's willingness to reassess "how it should approach evaluating requests for incentives,"[11] including considering requests based on the project's potential to achieve benefits for customers. National Grid believes that expanding the scope of its evaluations is reasonable and consistent with the Section 1241 of the Energy Policy Act of 2005. Furthermore, National Grid recommends that the Commission adopt a policy of granting, automatically, certain non-ROE incentives for transmission projects with a demonstrated likelihood of benefits. Automatic approval would be most appropriate for 100 percent of construction work in progress in rate base and recovery of 100 percent of prudently-incurred costs if a project is abandoned or cancelled for reasons beyond the developer's control. The Commission could rely on its existing standard to demonstrate that the investment satisfies the requirements of Section 219 (i.e., that the project results from a fair and open regional planning process that considers and evaluates the project for reliability and/or congestion and is found to be acceptable to the Commission or has received construction approval from an appropriate state commission or state siting authority).

We believe that such an automatic approval would be just and reasonable for several reasons. First, many of the non-ROE incentives created under Order No. 679 are intended to address specific risks and challenges of transmission development that persist today. In Orders Nos. 679 and 679A, the Commission identified specific risks and/or challenges of transmission development and created non-ROE incentives that were intended to address or mitigate those risks. For example, the Commission found that:

- The ability to include 100 percent of prudently incurred transmission-related CWIP in rate base and to expense prudently incurred "pre-commercial" costs was tied directly to improving cash flow for applicants, easing the pressures on finances

[11] NOI at P 14.

caused by transmission development programs, and maintaining a higher credit rating and lower cost of capital to the benefit of customers.[12]

- Inclusion of 100 percent of prudently-incurred costs associated with abandoned transmission projects where abandonment is outside the control of management to was linked to instances where "local, state and federal (as applicable) siting authorities reject an application outright."[13]

Risks associated with credit quality and potential cancellation have not decreased or diminished in the time since Order No. 679 was approved and therefore it is reasonable for the Commission to approve incentives to mitigate such risks. Second, the Commission has found that approval of these incentives, generally, provides benefits for customers. FERC notes that allowing the inclusion of 100 percent of CWIP in rate base helps insulate customers from rate shock that might otherwise accompany the use of AFUDC[14] and that the recovery of abandonment costs is an effective means to encourage transmission development by reducing the risk of non-recovery of such costs. Third, automatic approval of these non-ROE incentives offers administrative efficiency for the Commission and applicants. This would eliminate the need for applicants to prepare, and the Commission to consider, requests for non-ROE incentives, which have repeatedly been found to provide benefits to customers.

In the "Incentives Objectives" section of the NOI, the Commission has compiled a reasonable list of the expected benefits or project characteristics that warrant incentives. While each of the benefits or characteristics listed in this section produces some measure of benefit for customers, National Grid believes that the Commission should evaluate all the benefits of a given project or investment, on a case-by-case basis, before determining the appropriate award. National Grid sees customer value in most of the benefits listed and believes that incentives treatment can

[12] Order No. 679 at P 115.

[13] *Id.* at P 165.

[14] *United Illuminating Company*, 167 FERC ¶ 61,126 (2019) at P 36.

be particularly useful in several areas. First, flexible transmission system operations will be increasingly critical to transmission system operations in New York and New England. States therein have established a series of policies dedicated to meeting aggressive decarbonization targets, which will, among other things, drive significant changes to supply and demand dynamics (e.g. support the development of new renewables, drive the adoption of electric vehicles and charging infrastructure, prompt adoption of distributed generation, and alter demand patterns). Operating the transmission system amid these changes will require flexible system operations; incentives in this area would be critical to ensuring that the Commission continues to ensure robust transmission infrastructure and, at the same time, facilitates state and regional policy goals. Second, grid management technologies, including dynamic line rating and power flow control, can accurately assess power transfer capability, enhance system security, and improve fault detection on transmission lines in real time. As a result, transmission operators can maximize the economic value of the current transmission system.

With respect to how FERC should incentivize the benefit or project characteristics, there are several possibilities where the Commission finds that the applicant demonstrates sufficient benefits to customers. First, we believe that it would be appropriate for the Commission to award ROE-based incentives. The Commission has successfully applied ROE incentives in dozens of cases since Order No. 679. And, as noted, above, the non-ROE incentives created in Order No. 679 were designed to address specific transmission development risks/challenges; they are not applicable to the customer benefits analysis outlined above. Second, where a project or investment has created demonstrable savings for customers (e.g., where it has resulted in deferred investment in an alternative project to address the same need), National Grid believes it would be appropriate for the developer to share in the savings to customers. The appropriate split of those savings would be determined by the Commission on a case-by-case basis. Finally, it would be reasonable to include certain costs that are typically recovered through operations and maintenance expenses as a regulatory asset.

Regarding existing incentives, the Commission should not revise the RTO-participation incentive. National Grid continues to believe that 50 basis points is a just and reasonable level for that incentive. Furthermore, because transmission owners do not join and participate in an RTO/ISO on a project-specific basis, this incentive should continue to be applied to all assets under the control of the RTO/ISO. The benefits that customers realize from the RTOs/ISOs are rooted in the fact that it has operational control over a set of transmission assets. Thus, the Commission should reject the idea of selectively applying the RTO/ISO adder only to specific projects.

FERC created RTOs/ISOs to deliver an array of benefits to customers (e.g., regional transmission pricing, elimination of rate pancaking, improved congestion management, improved grid reliability, and reduced transaction costs)[15] and to "resolve impediments to fully competitive markets."[16] The benefits RTOs/ISOs provide to customers has only grown since then. Today, RTOs/ISOs provide a raft of benefits to customers, including:

- Centralized transmission planning over a regional footprint larger than an individual utility's service territory
- Coordinated sharing of operations across that same footprint
- Coordinated commitment of resources and dispatching economic supply resources
- Monitoring markets to prevent anti- competitive behaviors,
- Ensuring alternative resources can enter, and participate in, the wholesale markets

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[15] *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285 (December 20, 1999), (Order No. 2000) at P 90.

[16] *Id.* at P 115.

Transmission projects planned and built under ISO-NE's planning processes have resulted in hundreds of millions of dollars in savings for customers.[17] And at least one RTO – the Midcontinent ISO – estimates the value it provides to the region, including the entire set of market participants and customers. In 2018, MISO's study showed between $3.2 and $3.9 billion in annual economic benefits to the MISO region.[18] While this level of value cannot be assumed for other RTOs/ISOs, we believe those produce similarly significant benefits for market participants and customers therein.

National Grid raises two significant points with respect to participation in RTOs/ISOs. First, participation in these markets is voluntary and ongoing and therefore the benefits that membership produce for customers continues to accumulate. In Order No. 679, the Commission held that entities that have joined and remain members of RTOs/ISOs are eligible to receive this incentive based on "a recognition of the benefits that flow from membership in such organizations and the fact continuing membership is generally voluntary" and the eligibility for this incentive is "not tied to when the entity joined."[19] We believe that the Commission's reasoning, articulated in 2006, holds true today; where the Commission has already reached a reasoned decision, it should not change positions unless relevant circumstances require a change. If anything, relevant circumstances support retention of the incentive for RTO/ISO participation. RTOs/ISOs have evolved greatly since their inception and much of that evolution has been at the direction of the Commission. FERC has required RTOs/ISOs to revise their markets, processes, and tariffs to achieve an array of policy objectives that are not generally required of utilities outside of

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[17] Supplemental Answering Testimony of Kenneth B. Bowes on Behalf of the New England Transmission Owners, Docket No. EL16-64, Exh. No. NET-02600 at 9, and accompanying Exhibit No. NET-02601 (July 31, 2017).

[18] MISO Value Proposition (2018) *available at* https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/. For PJM see: https://www.pjm.com/about-pjm/value-proposition.aspx.

[19] Order No. 679 at P 331.

RTOs/ISOs. In Order No. 745, FERC required RTOs/ISOs to pay wholesale market rates to dispatchable, cost-effective demand response resources. Elimination of a federal right of first refusal in Order No. 1000 has created far more activity in RTOs/ISOs than in other planning regions. Order No. 841 requires each RTO and ISO to facilitate the participation of electric storage resources in those markets. In each case, the Commission found that such changes were necessary to ensure that wholesale market rates were just and reasonable and markets produce benefits for customers in those regions. As such, retaining the existing incentive reasonably awards transmission owners for the value of joining and continuing to participate in an RTO/ISO.

With respect to the mechanics and implementation of the Commission's incentives policy, rather than introduce new risks into transmission investment decision-making through potentially eliminating previously approved incentives, the Commission should provide clarity for investors by affirming that once granted, transmission incentives will remain in place for the useful life of a transmission project or asset. National Grid believes that a case-by-case evaluation of incentives requests remains appropriate, however, should the Commission consider automatic approval of incentives, it should prioritize the abandonment adder to address temporal challenges. National Grid does not believe that a more formulaic framework is necessary. We are concerned that a formulaic approach would necessarily fail to capture the full range of possible investments and/or projects, as well as the value those produce for customers. One of the Commission's goals in Order No. 679 was to "provide procedural options that offer applicants flexibility to address their construction and investment opportunities while at the same time ensuring that the resulting rates are just and reasonable and not unduly discriminatory or preferential."[20] We believe that this

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[20] *Id.* at P 76.

should remain an objective for the Commission, particularly as the electric sector (and the associated technology and resources) evolves.

In light of these considerations, National Grid seeks to address below many of the specific questions posed in the NOI. The responses below are organized by the four major headings and by the specific questions in those headings.[21] National Grid respectfully requests that the Commission consider these Comments in adopting future policies related to transmission incentives.

III. PROCEDURAL BACKGROUND

A. National Grid

National Grid is a transmission owner in New England and New York, under the operating authority of ISO-NE and the New York Independent System Operator, Inc. (the "NYISO"). National Grid serves approximately 3.4 million electric customers and owns and operates approximately 9,000 miles of overhead line in Massachusetts, New York, New Hampshire and Rhode Island, 377 transmission substations and 763 distribution substations. In addition, National Grid owns approximately 4,000 MW of mostly natural gas-fired electric generation on Long Island, New York. National Grid is also the largest distributor of natural gas in the northeastern United States, delivering gas to over 3.6 million customers in upstate New York, New York City, Long Island, Massachusetts and Rhode Island.

B. The History of the Commission's Incentives Policy

FERC's current incentives policy finds its genesis in Section 1241 of the Energy Policy Act of 2005 (EPAct 2005), also known as Section 219 of the Federal Power Act (FPA). While a detailed recitation of the history of the Commission's incentives policy is unnecessary because it

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[21] Where a question is not answered, National Grid takes no position on that question.

was well summarized by the Commission in the NOI,[22] National Grid notes that the Commission as a well-established record related to transmission incentives since 2005. That record includes Section 219, Order No. 679[23], Order No. 679-A[24], and the Commission's 2012 Policy Statement.[25]

The Commission's charge has always been the development of a framework for the use of transmission incentives to help ensure reliability and reduce the cost of delivered power by reducing transmission congestion. Incentives designed to encourage investment in transmission are the vehicle to reach the Commission's goal.

C. The Notice of Inquiry

On March 21, 2019, the Commission issued the Notice of Inquiry. In it, the Commission sought comments on the scope and implementation of its electric transmission incentives regulations and policy. Specifically, the Commission explained that, pursuant to its statutory obligations, it was engaging in public inquiry to determine whether it needed to, "add to, modify, or eliminate certain policies or regulatory requirements on incentives."[26] The Commission explained that it was issuing the NOI to obtain information to assist in evaluating its incentives policy and ensuring compliance with obligations under the FPA.[27] The Commission presented 105 questions on its incentives policy and asked commenters to, "respond to these questions in detail

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[22] NOI at PP 3-11.

[23] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) (Order No. 679).

[24] *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, 72 Fed. Reg. 1152 (Jannuary 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2007) (Order No. 679-A).

[25] *Promoting Transmission Investment Through Pricing Reform*, Policy Statement, 141 FERC ¶ 61,129 (November 15, 2012) ("2012 Policy Statement").

[26] NOI at P 13.

[27] *Id.*

and, where appropriate, provide specific examples to support their comments and recommendations."[28] National Grid responds to specific questions posed by the Commission in the NOI in the sections that follow.

IV. COMMENTS

A. Approach to Incentive Policy (Q 1-16)

1. Projects Should Continue to be Eligible for Incentives based on the Risks & Challenges They Face (Q1&2)

Overview:

Currently, an analysis of project risks and challenges is the sole basis for awarding incentives under Commission policy. National Grid believes that many of the "risks and challenges" that the Commission identified in Order No. 679 persist today. Thus, the Commission should continue to award non-ROE incentives based thereon. The Commission should expand its consideration, however, to include other bases such as expected project benefits and project characteristics. Given the variety of technology, projects, and project proponents, flexibility will be key to considering incentives in today's evolving world of transmission system investment and operation.

The Commission should retain the flexibility to award incentives based on its evaluation of requests for transmission incentives. It should not be a "check the box" exercise. The Commission's analysis should consider the totality of the circumstances in deciding whether the requested incentives vindicate the Commission's policies of ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.

Q1) Should the Commission retain the risks and challenges framework for evaluating incentive applications?

[28] *Id.*

FERC should recognize that the risks and challenges the Commission previously identified and incentivized continue today and justify the automatic approval of certain non-ROE incentives. In Order No. 679, the Commission identified specific risks and/or challenges of transmission development and created incentives that were intended to address or mitigate those risks. For example, the Commission found that:

- The ability to include 100 percent of prudently incurred transmission-related CWIP in rate base and to expense prudently incurred "pre-commercial" costs was tied directly to improving cash flow for applicants, easing the pressures on finances caused by transmission development programs, and maintaining a higher credit rating and lower cost of capital to the benefit of customers.[29]
- Inclusion of 100 percent of prudently-incurred costs associated with abandoned transmission projects where abandonment is outside the control of management to was linked to instances where "local, state and federal (as applicable) siting authorities reject an application outright."[30]

National Grid does not believe that these risks have decreased or diminished in the time since Order No. 679 was approved by the Commission and therefore it is reasonable to recognize this fact and rely on them for the purposes of granting non-ROE incentives. The Commission should retain flexibility to consider incentives applications based on risks and challenges as well as expected benefits, and project characteristics.

Q2) 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?

A showing of risks and challenges is not an adequate proxy for benefits or value. The risks and challenges framework established in Order No. 679 and supplemented in the 2012 Policy Statement focuses exclusively on the project development and construction phases of a project

[29] Order No. 679 at P 115.

[30] *Id.* at P 165.

(i.e., financing, permitting, and construction). Risks and challenges, as a framework, does not consider what a project delivers after being placed in service. Requiring a developer to outline the risks and challenges of developing, permitting, financing, and building the project does not shed light on how the project will produce value and benefits to customers when it is in service. A discussion of benefits is very hard to address in the risks and challenges framework.

2. Projects should be Eligible for Incentives based on their Anticipated Benefits and Incentives Based on Expected Project Benefits (Q4-9 & 11)

Overview:

In Order 679, the Commission recognized that Section 219 of the FPA was designed to benefit consumers by providing reliable and economically efficient transmission and ensuring reliability and reducing transmission congestion.[31] There is no reason why the Commission's incentives regime should not take these and other potential benefits into account when evaluating applications for incentives.

As stated above, the Commission should reserve the flexibility to award incentives with reference to the value / benefits anticipated to be created by a transmission project, either on its own or in conjunction with a consideration of risks and challenges and project characteristics.

To the extent that the Commission awards incentives based, in part, on expected project benefits, the level of incentive awarded should reflect the level of value or benefits created. For example, the Commission could value the incentive based upon reduction in congestion, enhanced capabilities, and/or reduction in customer costs.

Q4) 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?

[31] *Id.* at P 41.

Directly examining a project's expected benefits or value would be consistent with the goals of Section 219 of the Federal Power Act. In fact, the Commission has arguably already arrived at this conclusion. The Commission's 2012 Policy Statement identified investments in specific categories of transmission projects, stating that these projects "may face the types of risks and challenges that may warrant an incentive ROE."[32] The Commission then listed projects that:

- relieve chronic or severe grid congestion that has had demonstrated cost impacts to consumers;
- unlock location constrained generation resources that previously had limited or no access to the wholesale electricity markets; and
- apply new technologies to facilitate more efficient and reliable usage and operation of existing or new facilities.[33]

In this list, FERC wasn't identifying risks and/or challenges, rather, it was identifying benefits produced by certain types of transmission investment. The Commission was effectively linking the award of an ROE incentive to different categories of customer value: relieving congestion and costs thereof, delivering output from resources that have no path to markets (most notably: location-constrained renewable generation), and more efficient and reliable use of the existing transmission system. National Grid believes that an evaluation of project benefits can be very helpful in analyzing eligibility for incentives and that the NOI is making explicit what appeared to be implicit in the 2012 Policy Statement.

Q5) 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?

The Commission's approach to the evaluation of incentives should allow for flexibility. In adopting an incentives framework based upon the expected benefits and value of a project, the

[32] 2012 Policy Statement at P 21.

[33] *Id.*

Commission should establish broad principles, consistent with the requirements of Section 219, for the evaluation of the potential benefits of projects. National Grid believes that prescribing a narrow, bright line analysis of expected project benefits would be a mistake. Setting minimum triggers or thresholds, or only focusing on certain types of benefits may not survive the test of time as the needs of the transmission system evolve. The Commission's analysis should reflect the broad range of benefits and value that a project may deliver and the changing requirements that such projects may be required to meet. The Commission should provide for flexibility in the demonstration of the expected benefits and value delivered by a project. The Commission recognized this in Order No. 679-A. In considering challenges to the "nexus" test, the Commission rejected attempts to make the test more rigid: "The purpose of the Final Rule was to establish criteria to be applied in individual cases, not to provide an exhaustive list of situations where incentives will be granted or denied. The decision whether to grant or deny incentives to a particular project is appropriately the subject of an individual rate application (or declaratory order) where the Commission can evaluate whether the applicants have fully supported any incentive rate treatments being sought."[34] There is no reason to abandon this flexible approach.

Q6) How would a direct evaluation of expected benefits, instead of using risks and challenges as a proxy, impact certainty for project developers?

The direct evaluation of expected benefits from a project need not impact certainty for project developers. In establishing an incentive framework based upon expected benefits and value, the Commission could accommodate an application and award process at the same stage of a project life-cycle as the current risks and challenges framework. This would provide developers the same certainty that they have now. If the Commission is seeking to increase certainty for project developers, there are other avenues open to it, such as the 'automatic' award of incentives

[34] Order No. 679-A at P 24.

to certain categories of projects discussed immediately below.

Q7) Should transmission projects with a demonstrated likelihood of benefits be awarded incentives automatically? How could the Commission administer such an approach?

The Commission should consider the award of incentives on both automatic and case-by-case bases. As discussed elsewhere in these comments, National Grid supports the automatic approval of certain non-ROE incentives. The automatic award of incentives for transmission projects whose inherent characteristics, such as innovation or deployment of advanced technologies, demonstrate the likelihood of benefits, may be appropriate. For ROE incentives, the Commission should take a flexible approach to awarding incentives on a case-by-case basis.

Q8) 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 determine the level of incentives for projects based on expected benefits through the principle of proportionality. That is, the level of incentive should vary in proportion to the scale of the benefit relative to the costs of the transmission project concerned. The assessment of future benefits is intrinsically difficult, and while establishing a specific quantitative relationship may be impracticable, the Commission should retain the discretion to vary the level of incentive with the scale of benefits or value created. Anchoring this proportionality analysis will be the Commission's obligation to ensure that rates are just and reasonable.[35]

Q9) 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?

The Commission's approach to the award of incentives should be flexible, reflecting the wide range of benefits that transmission projects are able to provide as well as the changing nature

[35] Order No. 679 at P 65.

and requirements of the transmission system. The adoption of fixed benchmarks and ratios is not supportive of such flexibility. The award of incentives based upon expected project benefits should be made with reference to the demonstrated likelihood that the project will create such benefits. The Commission may make award of incentives automatic, or dependent upon the likelihood of project benefits, but the Commission should not tie itself to rigid benchmarks.

The Commission considered and rejected the application of a cost-benefit analysis in Order No. 679-A. First, the Commission found that a requirement to perform a cost-benefit analysis was inconsistent with Congress' determination that the Commission's traditional, non-incentives approach to ratemaking was not attracting sufficient transmission investment.[36] Second, the Commission found that its obligation to ensure just and reasonable rates provided protection that obviated the need to apply a cost-benefit analysis.[37] Third, the cost-benefit analysis approach fails to recognize, "that the courts have held that the Commission may consider non-cost factors in setting rates."[38] Lastly, the Commission found that the nexus test would impose adequate discipline on those seeking incentives.[39] National Grid maintains that the rationale for rejecting a cost-benefit analysis in Order Nos. 679 and 679-A continues to apply in the context of an expected benefits analysis.

Q11) 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?

As stated above, the Commission should promote flexibility in evaluating requests for

[36] Order No. 679-A at P 36.

[37] *Id.* at P 38.

[38] *Id.* at P 39.

[39] *Id.* at P 40.

incentives and not tie itself to specific benchmarks. The Commission's grant of an incentive based on the expected benefits or value of a project should be based on review and consideration of the project developer's demonstration of those anticipated benefits. The future ability of a project to deliver the anticipated benefits can be impacted by a range of factors outside of the developer's control, (e.g., changes in the network, changes in generation, changes in load, legislative change). Given the range of factors that can impact a project's ability to deliver anticipated benefits, the grant of an incentive should not be revoked due to rigid benchmarks which cannot anticipate future conditions. The risk of a transmission incentive being revoked in the future because certain benchmarks are not achieved would have a chilling effect on capital deployment for transmission investment.

3. The Commission should adopt a Flexible Approach to granting projects Incentives based on their Characteristics (Q12-16)

Overview:

The Commission should award incentives based on a range of project characteristics. Assuming the Commission adopts a reasonably flexible approach, its willingness to incorporate customer benefits as part of its approach to evaluating incentives requests should achieve the same outcome as identifying the characteristics of the project itself. FERC would presumably only identify characteristics to the extent that they would be cost-effective and provide benefits to customers (e.g., deployment of advanced technologies or unlocking constrained resources). Nevertheless, were the Commission to identify specific project characteristics, it should recognize that there is a wide range of characteristics that merit consideration for an incentives award and that a flexible approach both to recognizing and assessing incentive applications is necessary. Awards based on inherent characteristics of projects should be essentially administrative, (e.g., rules-based awards) while awards based on outcomes will require specific case-by-case consideration.

Questions:

Q12) 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?

Section 219 established an incentives regime, "for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion."[40] Section 219 required that the Commission:

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 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 the recovery of all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to Section 215 of the FPA, and all prudently incurred costs related to transmission infrastructure development, pursuant to Section 216 of the FPA (transmission national interest corridors).

[40] Order No. 679 at P 7.

Basing incentive awards on a range of project characteristics allows for closer alignment between the benefits that a project is anticipated to deliver and the requirements of Section 219. For example, project characteristics that enhance reliability and encourage deployment of new technology clearly meet the goals of Section 219.

Q13) If the Commission adopts an approach based on project characteristics, should it lay out general principles and/or bright line criteria for identifying or evaluating those characteristics?

As described in several places above, the Commission should adopt a flexible approach by establishing the broad criteria it will adopt in identifying and evaluating project characteristics that merit the incentive awards. The Commission should, however, retain discretion in the application of these broad criteria.

Q14) If so, how should applicable criteria be established, and, in cases where more than one criterion applies, how should they be evaluated in combination?

Consistent with Section 219, the criteria adopted by the Commission should recognize characteristics that are anticipated to ensure reliability, reduce the cost of delivered power and encourage the deployment of transmission technologies to increase the capacity and efficiency of transmission facilities.

Q15) How would an approach based on project characteristics impact certainty for project developers, particularly relative to the current risks and challenges framework?

Such an approach need not lead to significant impact on certainty for developers relative to the current risks and challenges framework. A framework for application and potential award of incentives for project characteristics could be established to operate across a similar stage of the project development cycle as the existing risks and challenges framework.

Q16) Should transmission projects with certain characteristics be awarded incentives automatically? How could the Commission administer such an approach?

Incentive awards based on inherent project characteristics, (e.g., advanced technologies) could be administered through a primarily rules-based approach. Awards based on the outcomes a project delivers will require more specific case-by-case assessment.

B. The Commission Should Provide Incentives Based on Project Benefits To Meet the Evolving Needs of the Transmission System (Q17-56).

Flexibility is the watch word that should guide the Commission as the modern electric grid is developed. Technological advances in electric generation and storage, a changing electric generation resource mix, evolving customer expectations, and increasing amounts of distributed electric generation and storage have placed the electric grid at a turning point - it is incumbent upon the electric industry's stakeholders and the Commission to exhibit flexibility in designing the electric grid of the 21st century. National Grid welcomes the Commission's decision to open this NOI to explore additional measures and methods by which the Commission can support the transmission investment needs of the future and meet its statutory obligation to help ensure reliability, resilience, and reduce the cost of delivered power.[41] National Grid supports the Commission's decision to examine whether its incentives policy should not only focus on the risks and challenges associated with a transmission project seeking incentives, but to entertain a wide variety of project benefits and attributes. The Commission's principle of evaluating incentive applications on a case by case basis is particularly relevant to evaluating incentives requests that go beyond the Commission's set of established non-ROE incentives (e.g., CWIP and abandoned plant). This will allow the applicant to demonstrate the unique characteristics of each project and the Commission to evaluate and consider the appropriate array of incentives to apply to each project.

Continued growth of renewable electricity sources and distributed energy and storage resources is fundamentally changing grid management. Utilizing these new energy sources

[41] 16 U.S.C. § 824s(a).

requires incentivizing transmission capital investment, whether through ROE adders or other mechanisms, to provide for the enlargement, improvement, maintenance and operation of transmission facilities, the deployment of technologies that enhance transmission capabilities, and new ways of managing the electric grid. The new paradigm of transmission investment and grid management will be oriented around flexibility, renewable energy generation, energy storage, and participation of demand as a resource - a fundamental departure from how the electric grid has historically been constructed and managed. The more flexible the power system, the easier it is for grid operators to manage the system around variable supply and demand. The changes coming to the bulk power and distribution systems – increased unpredictable supply variability from renewables, decreasing accuracy in traditional load forecasts, and the availability of a suite of new distribution system resources – mean that incenting, valuing, and deploying transmission investments will be the key to effectively operating an affordable, reliable, clean electric grid.

1. Projects that are Anticipated to Provide Special Reliability Benefits Should be Eligible for Incentives (Questions 17-20)

Q17) 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?

Reliability through compliance with applicable transmission design standards, (e.g., NERC, FERC, NPCC, etc.) is an essential requirement of transmission planning and a fundamental objective of the existing planning processes undertaken by RTO/ISOs. However, there are regions which have special reliability challenges, (e.g., fuel security) which go beyond currently established reliability requirements. Such challenges, and contributions to their resolution, should be recognized and incentivized. Finally, transmission investments will generally increase the reliability of the electric power system even when meeting reliability standards is not the primary purpose of the line.

Q18) Are there specific reliability benefits or project characteristics that could merit such an approach?

Transmission is the foundation of a reliable electrical system and a flexible transmission system will be a critical component for more cost-effectively serving electricity customers in a rapidly changing industry. In New England, and some other regions, fuel security is indicative of such challenges[42]. Thus, in those regions an example of a project that provided an additional reliability benefit would be one that accessed resources that, fully or partially, mitigated the fuel security issue. Additional examples include transmission investment that: avoids or defers additional reliability upgrades that would otherwise be necessary, increases operating flexibility, reduces the risk of load shed events, and increases options for recovering from supply disruptions. But given the changing environment in which we operate, the definition of reliability benefits that merit such an approach should not be limited to those challenges already evident but should remain flexible enough to also encompass other challenges likely to emerge in the future.

Q19) If the Commission tailored incentives for reliability benefits, how should the Commission measure the expected enhancement to transmission reliability? Should there be a threshold or bright line test applied? If so, how?

The Commission should adopt a flexible approach such that projects that provide reliability benefits beyond current standards and contribute to the resolution of special reliability challenges are assessed by the degree to which the reliability benefit they provide cost effectively mitigates the concerns they address. Furthermore, the Commission should not limit the types of reliability benefits that may qualify for incentive treatment. For example, if Commission incentives only focused on the ability of a transmission project to reduce loss of load probability, an alternative benefit of reduced planning reserve margin would be overlooked.

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[42] ISO-NE Operational Fuel Security Analysis (2018) *available at*: https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

Q20) Should the Commission incentivize transmission facilities that expand access to essential reliability services, such as frequency support, ramping capability, and voltage support?

The Commission should adopt a flexible approach to the recognition of special reliability challenges that regions may face and to the assessment of whether transmission projects mitigate such challenges. However, by way of example, if a project purported to have the benefit of reducing system planning reserve margin, the costs savings benefit could be estimated by calculating the difference in the cost of generation needed under the required reserve margins before adding the new project versus the cost of generation with the lower required reserve margins after adding the new project.

2. Incentivizing Transmission Development in Certain Geographic Areas Can Deliver Benefits (Question 26)

Q26. 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?

Granting incentives for transmission in targeted geographic areas (on-shore and off-shore) would further the Commission's mandate to help ensure reliability, resilience, and reduce the cost of delivered power, creating benefits for customers. Operational requirements, state policies, and economic project development considerations frequently drive the siting of intermittent renewable generation resources to remote geographic areas far from load centers that possess underdeveloped or non-existent transmission networks. Incentivizing transmission development in certain geographic areas will not only support public policy objectives that favor renewable generation, but also may result in net cost reductions for electricity consumers as the costs associated with balancing intermittent resources is reduced by interconnecting larger portions of the electric grid and by providing access to potentially lower cost generation resources. Therefore, while transmission investments to serve remotely-located renewable generation may increase the cost of delivering renewable generation power in the short term, the savings associated with reducing the system balancing costs, lower generation production costs, and achieving other reliability, economic, and societal benefits can exceed the incremental cost of those transmission projects. Expansion of transmission into certain geographic areas may also dovetail with future transmission expansion investments. For example, a transmission investment may not only provide benefits as a standalone project but may also be a common element in regional transmission system plans, or the integral part enabling future transmission expansions in a geographic area.

There is no need for the Commission, system planners, state policymakers, or any other entity to designate or otherwise predetermine the relevant geographic area. This would require additional processes, which would no doubt be contested, and presumably an affirmative finding by the applicable system planner and/or Commission. National Grid does not believe that this would be a useful way to spend time and planning resources. Instead, any applicant seeking an incentive on the basis that the project in question addresses a persistent geographic need should be permitted to make that demonstration to FERC on a case-specific basis. In fact, FERC has already granted a ROE incentive for just such a project without defining the relevant geographic area. In 2018, FERC determined that the Empire Project in New York would relieve chronic or severe congestion that has had demonstrated cost impacts on consumers and approved a 50-basis point return on equity incentive adder.[43] In doing so, FERC relied on the results of a congestion study, the 2015 State of the Market Report, and a NYISO planning report to identify the ultimate benefits

[43] *NextEra Energy Transmission New York, Inc*., 162 FERC ¶ 61,196 (2018) at P 38.

to customers. Insofar as FERC entertains incentives on this basis, the 2018 Order on the Empire Project in New York serves as an appropriate model.

3. Flexible Transmission System Operation Will be Key in Supporting the Transition to Different Supply and Demand Mixes (Questions 29-31)

Q29) How can flexibility characteristics improve the operation of the transmission system?

Flexibility in the context of transmission means having the required infrastructure to maintain the ability to respond over various time frames – from seconds to seasons – to changes in supply, demand, and net load. The more flexible the power system, the easier it is for public utilities and grid operators to manage the system around variable supply and demand. The Commission's proposed definition for the resilience of a transmission system is focused on the ability of the system to withstand disruptive events and to also recover rapidly from such events. Flexibility in the configuration and operation of a transmission system are key elements in meeting these two elements of the Commission's proposed definition of resilience. Transmission investment can enable flexible grid operation through the interconnection of different resource mixes, thereby diversifying the fuel mix in a region. Transmission can also provide resource planning flexibility by strengthening the regional power grid and lowering the cost of addressing exigent circumstances such as drastic fuel cost changes, fuel delivery constraints, and plant retirements.

National Grid is facilitating advanced technologies that can enhance the flexible and reliable operation of the transmission system. For instance, when energy storage technology can provide the cost-effective solution to a need, it can respond to a range of grid challenges, including solar energy ramp rates and power quality issues. Promoting the growth of energy storage through a targeted incentive for cost-effective advanced technologies, in concert with the development of fair and open wholesale market participation rules, is an ideal outcome to benefit customers and achieve the goals of Section 219.

Q30) Should the Commission incentivize flexibility characteristics and, if so, how should it do so?

Yes. Flexibility is a key characteristic in support of the resilience of a transmission system and as such should be incentivized. The Commission should consider the award of both existing incentives (ROE and non-ROE) and of new incentives such as the capitalization of other costs if they are demonstrated to enhance flexibility.

Q31) How could the Commission define "flexibility" in this context?

The Commission should define "flexibility" as "facilitating the transmission system's ability to respond to changing circumstances." "Circumstances" could include rapid changes in generation or load, including those due to intermittent resources. Examples of transmission initiatives that can enhance flexibility may include, but should not be limited to: (1) Transmission monitoring (e.g. power flow control, dynamic line/ transformer ratings and topology control) which provides better utilization of equipment capabilities, leading to improved operations, functionality and flexibility of key transmission infrastructure essential to the reliability of the network; (2) Energy storage projects that improve overall network reliability and efficiency, and mitigate power quality issues; and (3) Fiber optic projects and enhancements to improve communication and bolster resiliency while meeting inherent consumer demand. Generally, more flexible operation will be required for the transmission system in the future due to long-term trends in investment and policy that are changing the nature of generation and distribution.

4. Resilience (Questions 34-36)

Q34) Should transmission projects that enhance resilience be eligible for incentives based upon their reliability-enhancing attributes?

The Commission has proposed that resilience means the ability of the transmission network to withstand and reduce the magnitude and/or duration of disruptive events, which includes its capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event. The ability to withstand and to rapidly recover from disruptive events, (i.e., resilience) is directly related to the way the network is designed, monitored and operated. Transmission projects that lower the cost of addressing exigent circumstances such as drastic fuel cost changes, fuel delivery constraints, plant retirements, and projects that reinforce existing infrastructure to withstand storm and weather damage, or that enhance the ability to acquire data, analyze, and exert appropriate control of the network in real-time, are all examples which further this ability.

National Grid is evaluating advanced technologies that could enhance grid reliability and resilience. First, Robotic or UAV-assisted inspection and maintenance can potentially improve the safety and efficacy of asset management capabilities, reduce long-term operating expense and optimize asset replacements and deployment. Second, the development of robust asset management systems and automated analytics would increase system reliability by providing clarity and decision support for asset management and engineering functions and insight for future asset health diagnostics. These enhancements enable real-time monitoring and condition-based maintenance to drive efficiency. Finally, National Grid is evaluating a systematic program of digital substations upgrades to all our transmission substations. The IEC 61850 standard will enable automated substation operations, reduce costs, and improve system analytics and interoperability. Such a program would support resilience in that it allows us to monitor the condition of key equipment in real time, minimizing risks to the network. With real-time monitoring and diagnostics National Grid can actively manage cyber security across our network and optimize the use of protection and control equipment to accommodate the increasing penetration of distributed energy resources and variable generation. Providing incentives for similar innovative applications of advanced technology in transmission will produce commensurate benefits by facilitating forward-looking transmission planning and investment.

Q35) If so, how could the Commission consider or measure the benefits of an individual project towards grid resilience?

The transmission network's design, together with the ability to monitor and operate it in response to real-time information is essential to withstanding, and recovering from, disruptive events. The Commission should review and evaluate the proposals of individual, or groups of, transmission owners to enhance this ability to determine their effectiveness in achieving this goal and thus of resilience.

Q36) If the Commission were to grant incentives for measures that enhance the resilience of the transmission system, what incentive(s) would be appropriate?

The Commission's current incentive policy is focused on the development, (e.g., Abandonment) and capital investment, (e.g., ROE) in transmission assets. While resilience is related to the transmission infrastructure in place, it is also dependent on activities such as the capture, analysis, and interpretation of large amounts of data from across the network in real-time to support the appropriate operational responses to disruptive events. The software tools and activities that enable and support this ability typically involve expenditures that are classified as operational costs and fall outside the Commission's current incentive policy. The Commission should consider broadening its policy to allow for such costs to be included, whether by their "capitalization" or otherwise.

5. Improving Existing Transmission Facilities (Questions 37-41)

Q37) How should the Commission incentivize the deployment of technologies and other measures to enhance the capacity, efficiency, and operation of the transmission grid? How can the Commission identify and quantify how a technology or other measure contributes to those goals? Please provide examples.

The Commission should consider eligible a technology or investment that meets one or more of the criteria specified by statute (capacity/efficiency/operation). For example, energy storage projects improve grid capacity providing energy at the time it is most needed, improves operation by mitigating challenges associated with generator ramp rates, and improves efficiency and reduces costs to consumers by allowing utilities to defer additional infrastructure builds. In some instances, the ability of a technology to contribute to the capacity, efficiency and operation of the transmission grid will be self-evident through a review of the technology itself and its use. In other instances, quantifiable criteria related to reliability, loss of transmission assets, or anticipated production cost savings may be used to measure the benefits of a technology or project.

Q38) 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?

The Commission should avoid returning to the "routine"/"non-routine" distinction it moved away from in the 2012 Policy Statement.[44] Applicants should demonstrate that the projects or "package" seeking an incentive provide benefit to consumers and/or are subject to risks and challenges.

Q39) How should a transmission owner seeking this type of incentive demonstrate increases or improvements in the capabilities or operations of existing transmission facilities?

Test data or support from pilot programs is one option; support from ISO/RTO reliability-based planning process is another; forecasts and studies may also be utilized.

Q40) 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?

[44] 2012 Policy Statement at P 8.

The Commission should reconsider its move away from a stand-alone technology incentive, particularly as digitalization and other major trends (e.g. renewable energy integration) is likely to change how the grid is operated. Order No. 679 declined to list specific technologies but supported technology "that may indirectly mitigate congestion and enhance grid reliability, if such technologies can be shown to increase the capacity, efficiency, or reliability of an existing or new transmission facility."[45] The Commission should maintain openness to changes in technology over time to foster a culture of innovation within public utilities.

Q41) Certain utility costs, such as those associated with grid management technology, including dynamic line rating technology, are typically recovered through operations and maintenance expenses within cost-of service rates. For such costs, should the Commission, instead, consider inclusion of these expenses in rate base as a regulatory asset? If so, what costs should be eligible for such treatment and over what period should they be amortized?

Dynamic line rating (DLR) technology provides benefits for consumers and fulfils the Commission's statutory mandate under FPA Section 219, and therefore, should be considered for incentive rate treatment. Investments in dynamic rating can drastically improve transmission operation utilization. National Grid estimates that dynamic line rating technology can provide real-time capacity gains of approximately 30 percent above static line ratings. These estimates are buttressed by the results from the Department of Energy's Smart Grid Demonstration Project with the New York Power Authority in 2014 which also showed average adjusted real-time capacity gains of at least 30 percent above static line rating.[46] Considering these findings, DLR investments can reduce electricity costs for consumers and therefore should be considered by the Commission for inclusion in rate base.

[45] Order No. 679 at P 291.

[46] 2012 Policy Statement at P 10.

6. Incentive Policy Should Recognize the Greater Risks and Challenges Associated with Interregional Projects and the Potential for Greater Benefits (Questions 44-46)

Q44) 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?

Interregional transmission projects should be eligible for incentives awarded within the same frameworks as other transmission projects, including those developed under Order No. 1000.

Q45) If the Commission should use incentives to encourage interregional transmission projects, should all interregional projects be eligible or should it be based on some other criteria? How should the Commission consider the benefits of an individual interregional transmission project?

All interregional transmission projects should be eligible for incentives. The successful development of interregional transmission projects will require interaction with and approval from the respective regional transmission planning processes involved. It will also require an agreed determination of the benefits received and thus the apportioning of costs between those same parties. The Commission should recognize that both the risks and benefits associated with interregional transmission projects are intrinsically greater than single-region transmission projects in the consideration of incentive awards to interregional transmission projects.

Q46) If the Commission were to grant incentives for interregional transmission projects, what incentive(s) would be appropriate?

Interregional projects should be eligible for the same range of incentives against the same frameworks for the award of incentives as other regional projects.

7. Order 1000 Transmission projects (Questions 52&54)

Q52) Should these [CWIP, abandoned plant and regulatory asset treatment] or other incentives be granted automatically for transmission projects selected in a regional transmission plan for purposes of cost allocation?

As discussed above, National Grid supports automatic granting of certain non-ROE incentives to transmission projects with a demonstrated likelihood of benefits. Automatic approval would be most appropriate for 100 percent of construction work in progress in rate base and recovery of 100 percent of prudently-incurred costs if a project is abandoned or cancelled for reasons beyond the developer's control. The Commission could rely on its existing standard to demonstrate that the investment that satisfies the requirements of Section 219 (i.e., that the project results from a fair and open regional planning process that considers and evaluates the project for reliability and/or congestion and is found to be acceptable to the Commission or has received construction approval from an appropriate state commission or state siting authority).

In addition to the customer benefits described above, automatic granting of the abandonment incentive would resolve a particularly challenging phenomenon. Under current policy, a transmission developer can only recover up to 50 percent of prudently incurred abandonment costs incurred before the date of the Commission's order granting the incentives. If FERC were to create an automatic incentive and tie that incentive to the beginning of project development, this would resolve the challenges associated with waiting for the date of the Commission's order approving the abandoned plant incentive. Recovery of specific abandonment costs would remain subject to a case-specific proceeding to examine the prudency of the development costs.

Q54) Should the Commission continue to use certain incentives to seek to place non-incumbent transmission developers on a level playing field with incumbent transmission owners in Order No. 1000 regional transmission planning processes? If so, should the Commission consider requests for such incentives under Section 205, or should the Commission consider requests for such incentives for non-incumbent transmission owners under Section 219?

In the development of Order 1000 projects, incumbent and non-incumbent are competing under common tariff requirements. Any advantage either party may have, (e.g., flexibility in financing or network knowledge), and conversely, any disadvantage suffered, do not merit awarding additional incentives.

C. RTO/ISO Participation and the Transco Business Model both continue to Deliver the Benefits that the Respective Incentives Were Intended to Encourage, Thus These Incentives Should be Retained (Q 57-82)

1. ROE-Adder Incentives (Q57-67 &69)

Overview:

The Commission should retain the RTO/ISO participation and the standalone Transco ROE adder. RTO/ISO membership creates value and benefits for customers and the value and benefits created by RTO/ISO participation depends on continued participation. Similarly, the Commission has found that Transcos have a good record of transmission investment and that their singular focus on transmission investment by transmission-only companies, and their access to capital markets, demonstrate the benefit of Transcos.[47] Additionally, the Commission should encourage the development of advanced technologies and should have a specific and transparent process for award of an Advanced Technology ROE incentive.

Q57) 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?

The characteristics of the Transco business model have not changed since FERC affirmed their benefits in Order No. 679-A. Transcos continue to provide focus on transmission investment since Transcos are transmission-only companies. They also eliminate competition for capital between generation and transmission functions.[48] As such, they continue to provide the benefits identified as meriting transmission incentives. An entity seeking the Transco incentive should be

[47] Order No. 679-A at P 77.

[48] *Id.*

able to demonstrate that it does not experience internal competition for capital investment with other types of facilities. Additionally, the Commission should continue to base Transco incentive eligibility on a showing of how the specific characteristics of a proposed Transco affect its ability and propensity to increase transmission investment.[49]

Q58) 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?

While the Commission has not prescribed a specific methodology to determine independence, it does consider the "level of independence" in its analysis.[50] Moreover, in Order No. 679, the Commission stated: "A Transco with active ownership by a market participant or other new business arrangements is also eligible for Transco incentives to the extent it can show, for example, why active ownership by an affiliate does not affect the integrity of its investment planning, capital formation, and investment processes or how its business structure provides support for transmission investments in a way similar to the structure of non-affiliated Transcos or Transcos with only passive ownership by market participants."[51] The Commission should continue to apply its current 'independence' test, assessing the level of independence and assessing whether there is internal competition for investment funds between an entity seeking a Transco incentive and any affiliated market participant. If there is such competition for investment funds between the two relevant entities, then the applying entity should not be eligible for the Transco incentive.

Q59) Should a Transco incentive be awarded on a project-by-project basis?

[49] Order No. 679 at P 202.

[50] *Id.* at P 239.

[51] *Id.* at P 240.

The Transco incentive should be awarded to the entity itself, not on a project-by-project basis. As stated above, if an applicant can demonstrate that a Transco does not experience internal competition for capital investment and can show how the Transco's specific characteristics would increase transmission investment, it should not be required to make a project-by-project showing.

Q60) Should the Transco incentive exclude assets that a Transco buys, rather than develops?

In Order No. 679, the Commission identified the importance of providing to Transcos an ROE that both encourages Transco formation and is sufficient to attract investment after the Transco is formed.[52] These criteria remain sound and it should not matter how the asset is obtained. The Transco incentive should include all those assets owned by a Transco.

Q61) Should the Commission revise the RTO-participation incentive?

The Commission should retain the existing incentive for RTO/ISO participation at the same level. The EPA Act of 2005 directed the Commission to "provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization." RTO/ISO participation creates benefits for customers, including:

- Coordinated transmission planning across multi-utility service territories
- Centralized dispatch of generation
- Reserves sharing
- independent transmission system access
- Foster alternative resource options

ISO participation has had tangible benefits for National Grid customers. NYISO is currently planning transmission to address policy needs while ISO-NE planned transmission over last 15 years has created benefits for National Grid customers.

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[52] *Id.* at P 221.

There is ample authority in Order No. 679 for retaining the RTO/ISO incentive for continued participation. For example, the Commission stated: “We will not make a generic finding on the duration of incentives that will be permitted for public utilities that join Transmission Organizations. An entity will be presumed to be eligible for the incentive if it can demonstrate that it has joined an RTO, ISO, or other Commission-approved Transmission Organization, and that its membership is on-going.”[53]

The Commission further suggested that the incentive was not limited to the date of joining: “The basis for the incentive is a recognition of the benefits that flow from membership in such organizations and the fact continuing membership is generally voluntary. Our interpretation of the statute is that eligibility for this incentive flows to an entity that "joins" a Transmission Organization and is not tied to when the entity joined.”[54] The Commission provided further support for on-going RTO/ISO participation when it stated, “[i]t would also be unduly discriminatory for the Commission to consider the benefits of membership in determining the appropriate ROE for new members but not for similarly situated entities that are already members.”[55]

The Commission should not limit the duration of the RTO/ISO incentive. The benefits created by transmission facilities are not confined to a limited period; they last for the life of the facilities. FERC considered this in Order No. 679 (see P 36) but did not apply that to the RTO adder at the time; nor has it done so since.

Q62) 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?

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[53] *Id.*at P 327.

[54] *Id.* at P 331.

[55] *Id.*

The Commission's current approach of providing ROE adders has been successful in encouraging public utilities to become, and remain, members of RTO/ISOs. Given the success of the Commission's current approach it should be retained rather than considering the provision of an alternative incentive.

Q63) If the Commission continues to provide ROE adders for RTO/ISO participation, what is an appropriate level for an ROE adder?

At its current level, the ROE adder granted by the Commission for RTO/ISO participation has proved successful. Any reduction in the current level of the ROE adder would send the unintended and undesirable signal that the Commission was downgrading its view of the value of RTO/ISO membership which could have a chilling effect.

Q64) Should the RTO-participation incentive be awarded for a fixed period of time after a transmission owner joins an RTO or ISO?

The benefits of RTO/ISO membership that flow to customers commence when an entity joins an RTO/ISO and continue while that entity remains a member of an RTO/ISO. The benefits created through membership do not reduce or disappear a fixed period of time after joining an RTO/ISO. Accordingly, the RTO-participation incentive should be awarded when a public utility joins an RTO and should continue for the entire period of membership.

Q65) Should the RTO-participation adder be awarded on a project-specific basis?

The benefits that are realized through RTO/ISO membership, (e.g., a coordinated regional planning process, the sharing of generation reserves, etc.) are realized across the whole of the transmission facilities comprising the network within an RTO/ISO. Given that the benefits of RTO-participation are realized in a such holistic, rather than on a project-by-project manner, the ROE adder for participation should be applied in a similarly holistic manner. That is, it should be awarded to entities that join and remain members of RTOs and should apply to all the transmission projects of that entity.

Q66) 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?

The Commission has correctly found that the benefits flow from membership. The Commission should look to whether there is membership, not whether such membership is voluntary, in awarding the incentive.

Q67) Why have few transmission developers sought transmission incentives for the adoption of advanced technology?

Under the current incentive regime, making the required showing for transmission incentives for the adoption of advanced technology is challenging. If the Commission expands the evaluation of ROE incentives requests to account for customer benefits/value, it will be easier for applicants to make a much more robust demonstration of the reasonableness of the requested incentives, including a request for an advanced technology incentive.

Investment in new technology is also costly, so transmission developers must balance the costs and benefits to customers. To help address this challenge, FERC should also consider granting an incentive in circumstances where the application of new technology allows for the deferral of other investments and creates savings for customers. Such an incentive could be measured by the difference between the costs of prudent alternative and the costs of new technology). In that case, FERC should consider permitting the sharing of those savings between customers and developer as an incentive for investment in new technology.

Q69) Are there any types of transmission incentives that could better encourage deployment of new technologies? If so, please describe them.

As referenced above, National Grid is aware of the costs to customers from new transmission asset construction. However, advanced grid technologies, including energy storage, could provide reliability, increase resilience, and reduce the need for traditional transmission lines. Further, sharing the cost savings benefits of deferring new transmission investment between customers and utilities would provide an incentive for transmission owners to pursue non-wires alternatives or other similar advanced technology.

2. Non-ROE Transmission incentives (Q70 & 77-79)

Overview:

In the 2012 Policy Statement, the Commission recognized that certain risks are not accounted for in the base ROE.[56] Rather, the Commission affirmed, certain transmission incentives, "such as recovery of 100 percent of Construction Work in Progress (CWIP), recovery of 100 percent of pre-commercial costs as an expense or as a regulatory asset, and recovery of 100 percent of prudently incurred costs of transmission facilities that are abandoned for reasons beyond the applicant's control – reduce the financial and regulatory risks associated with transmission investment."[57]

National Grid supports maintaining these non-ROE transmission incentives and awarding them on an automatic basis for certain projects. The Commission identified specific risks and challenges that each of these non-ROE incentives are meant to address. For example, the CWIP incentive addresses financing risks and credit quality, while the Abandoned plant incentive addresses permitting risks.[58]

These risks have not decreased since the issuance of Order No. 679 and thus there is no

[56] 2012 Policy Statement at P 11.

[57] *Id.*

[58] *Id.* at P 12 and P 14.

reason to eliminate them via the NOI. For example, projects have been cancelled since Order No. 679 and the risk of cancellation, for any number of reasons, continues. In fact, Order No. 1000 may increase the prospects of cancellation, given the downward pressure on costs resulting from competition and given the introduction of newer, less experienced developers undertaking complex transmission projects. Developers have continued to seek and receive the abandoned plant incentive and the Commission recognizes that the risks remain.

There is no need to eliminate these incentives. To do so would arguably make transmission development more difficult at a time when transmission will be needed to meet increases in renewables and forecast increases in the demand for electricity.

Q70) 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?

According to the Commission, the CWIP incentive provides, "up-front regulatory certainty, rate stability and improved cash flow, which in turn can result in higher credit ratings and lower capital costs."[59] In other words, these incentives relate to specific risks that remain relevant and should be retained.

Q77) 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?

Yes. As discussed elsewhere, the Commission should make the grant of the abandoned plant incentive automatic under certain circumstances, such as where the cancelation of a project is beyond the control of the developer. For example, the Commission recognized in Order No. 679 that when a siting authority rejects an application outright, that rejection should be deemed

[59] *Id.* at P 12.

"abandonment beyond the control of management."[60] In that case, a transmission developer should not be penalized but should receive the incentive automatically.

Also, where there is a regional transmission planning process which identifies required transmission facilities, and the entity responsible to construct those facilities fulfills its obligation to do so, where a re-assessment via the regional process leads to the cancellation of a transmission project, the award of the abandoned plant should be automatic.

Q78) How, if at all, could the Commission grant the abandoned plant incentive without encouraging transmission developers to pursue unnecessarily risky transmission projects or take unnecessary risks in transmission development? Could such behavior be reduced if the developer shared some risk associated with the abandonment, e.g., 10 percent of abandonment costs? If so, what level of developer risk is appropriate?

The automatic grant of abandonment would be only in the circumstance where there is a regional planning process identifying the appropriate transmission project that should be developed. The regional planning process mitigates the risks set out in question 78.

Q79) How should the Commission evaluate whether the costs of an abandoned facility were prudently incurred?

As stated above, National Grid supports granting the abandoned plant incentive in certain circumstances, (i.e., within a regional planning process). Accordingly, in determining whether the costs associated with the abandoned plant were prudently incurred, the Commission should look to whether the abandoned project is one that was selected, initiated and then abandoned through the operation of a regional planning process. If so, the Commission should assume that the abandoned costs have been prudently incurred.

[60] Order No. 679 at P 165.

D. The Commission Should Take a Holistic Approach to Evaluating Transmission Project Benefits and Maintain Flexibility When Determining the Appropriate Incentive. (Q 83-97)

All transmission projects that can provide benefits to the electrical grid should be harnessed. To this end, National Grid supports the Commission's examination in this NOI of various types of potential transmission benefits that could qualify for incentives, notes that projects may provide more than one benefit, and encourages the Commission to be open to applicants demonstrating other kinds of benefits not specifically addressed in this NOI. The Commission should be wary of limiting its benefits analysis to the impacts of new projects on customer rates. Such a perspective is important because those who pay for the transmission facilities should also obtain benefits that are "commensurate" with their share of costs - however, a benefit analysis limited to the direct rate impact on customers, especially customers in a single utility footprint or planning region, could miss benefits such as increased customer value from improved reliability and ignore benefits to other regions, the electric grid as a whole, or various market participants. Conversely, an electricity-customer perspective can overstate benefits relative to true gains by ignoring costs imposed on other market participants or regions. To avoid under or overstating the total benefits of transmission investments, benefit analyses of transmission projects should consider the overall benefits that accrue to a broad range of customers, regions, market participants and the electric grid. In conjunction, the Commission should exhibit flexibility when determining the appropriate incentive or group of incentives, including ROE levels, available to a transmission project by focusing on the value and benefits a project delivers.

1. Duration of Incentives (Questions 83)

Q83) Should the Commission limit the duration of a granted transmission incentive? If so, should this limit be based on the type of incentive granted?

The decision and ability of a developer to proceed with a transmission project is ultimately influenced by an incentive award. The granting and subsequent withdrawal of an incentive award, while the circumstances of the recipient project remain unchanged, would be inconsistent with the initial assessment that the project created value / benefits or undertook risks / challenges and could be retrospective ratemaking. The risk associated with the potential for an incentive award being removed in future could chill transmission investment, particularly because as the electric grid evolves to support more distributed energy resources, investments in distribution assets may become viewed more favorably vis-à-vis transmission assets. Rather than introduce new risks into the realm of transmission investment decision making through the potential for incentive removal, the Commission should provide clarity for investors by affirming that once granted, transmission incentives will remain in place for the useful life of a transmission project or asset.

2. Interaction Between Different Potential Incentives in Determining the Correct Level of ROE incentives (Questions 93-95)

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?

The Commission should establish frameworks for the award of incentives that consider both the value / benefits created and the risks / challenges undertaken. The Commission should also retain its existing flexibility in the application of these frameworks. The needs of the transmission system are diverse and ever changing, and the Commission's policies to incentivize transmission development to maintain reliability and reduce congestion and consumer cost should likewise be flexible to meet the needs of the electric grid.

Q 94) Alternatively, if the Commission continues evaluating incentive requests on a case-by-case basis, how could the Commission provide more detailed explanations in individual cases to better describe how it derives the appropriate level and combination of incentives? If so, what elements should such explanations provide?

The Commission should continue to evaluate ROE incentives on a case-by-case basis, and a detailed discussion and analysis of such evaluations within the proposed frameworks would increase the transparency of the process and enhance the understanding of the results for the applicant and future applicants.

Q95) 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?

If a transmission project qualifies for the award of a ROE incentive, the level of that incentive should be related to the level of value / benefits created or the risks / challenges undertaken, regardless of the upper limit of the zone of reasonableness. If an innovative project could result in substantial benefits to the electric grid and consumers, that project should be incentivized accordingly. Otherwise, innovation will be chilled and the goals of Section 219 of the FPA would be thwarted - in particular, the encouragement of technologies and measures to increase the capacity and efficiency of transmission facilities and their operation.

Moreover, if a total ROE was within the statutory zone of reasonableness when an incentive ROE was first added, it would be inconsistent with Congressional intent in enacting Section 219 to later reduce the level of an incentive ROE adder that a utility can realize because the statutory zone of reasonableness changed in a later case.

3. Bounds on ROE incentives (Questions 96-97)

Q96) For ROE incentives, to what extent, if any, should the Commission retain discretion to determine the appropriate level of ROE incentives?

The Commission should retain its current discretion to determine the appropriate level of a ROE incentive. See National Grid's response to Question 95.

Q97) If the Commission retains discretion with respect to determining ROE incentives, should its discretion be bound within a pre-determined range (e.g., between 50 and 100 basis points)? If so, what is the appropriate range and why?

The appropriate level of a ROE incentive should reflect the assessed level of value created or risks / challenges undertaken and not be constrained within a pre-determined range. Adoption of a pre-determined range would be unable to reflect the circumstances of projects who merit incentives awards above or below any pre-determined range. See National Grid's response to Question 95.

IV. CONCLUSION

For the reasons discussed above, National Grid respectfully requests that the Commission take these comments into account as it considers the issues presented in the Notice of Inquiry.

Respectfully submitted,

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