U.S. HOUSE OF REPRESENTATIVES
COMMITTEE ON ENERGY AND COMMERCE

May 8, 2018

TO: Members, Subcommittee on Energy

FROM: Committee Majority and Minority Staff

RE: Hearing entitled "Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction, and Alternatives."

INTRODUCTION

The Subcommittee on Energy will hold a hearing on Thursday, May 10, 2018, at 10:00 a.m. in 2123 Rayburn House Office Building. The hearing is entitled "Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction, and Alternatives."

This hearing will review the activities of the electric transmission sector, including challenges associated with the planning and construction of new transmission lines, the effect of existing federal laws and regulations, and the consideration of non-transmission alternatives and technologies.

WITNESSES

- **Tony Clark**, Senior Advisor, Wilkinson Barker Knauer, LLP;
- **Edward Krapels**, CEO, Anbaric Development Partners**;**
- **Jennifer Curran**, Vice President, System Planning, Midcontinent ISO;
- **Ralph Izzo**, CEO, Public Service Enterprise Group Inc.;
- **John Twitty**, Executive Director, Transmission Access Policy Study Group; and
- **Rob Gramlich**, President, Grid Strategies LLC.

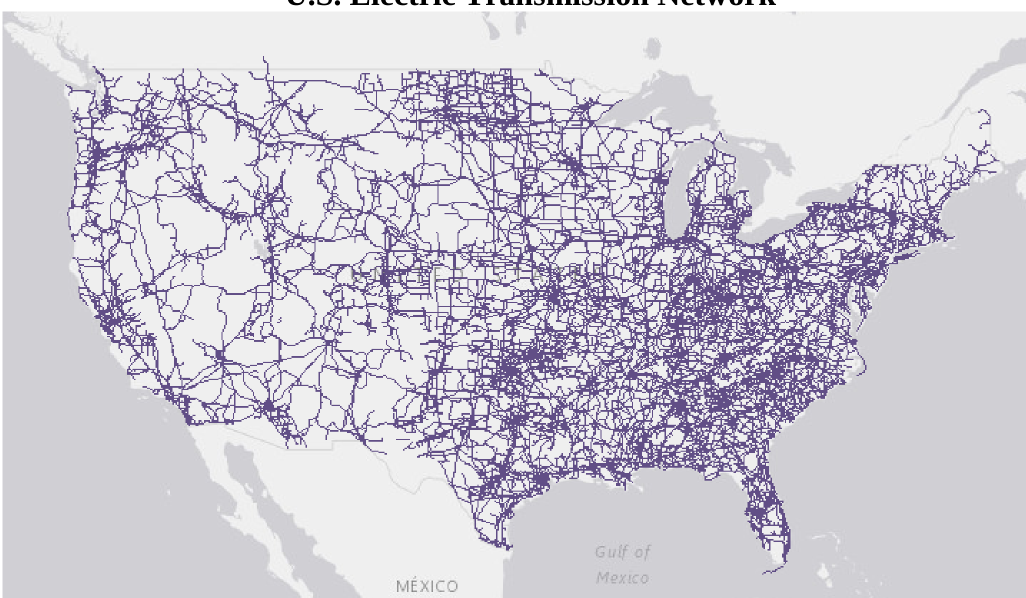
BACKGROUND

The U.S. electric transmission network is often referred to as the largest interconnected machine in the world. With more than 240,000 circuit miles of transmission lines, this high voltage network forms the backbone of the power grid by transporting the power from electric generators to local distribution utilities, which ultimately deliver the electricity to end-use customers. The public relies on a robust, reliable, and resilient transmission network to supply affordable electricity to power homes and businesses on an uninterrupted basis. However, like other forms of infrastructure, the nation's electric transmission infrastructure requires continual maintenance, modernization, and investment to ensure that the grid continues to deliver a range of benefits in a rapidly changing energy environment.

Although electric transmission provides a relatively simple service by transporting electrons between two points on a grid, developing new transmission line infrastructure is difficult for many reasons. Each stage of transmission development, from planning a new high-voltage line, to securing capital and allocating the costs, takes time – often years. Additionally, siting transmission lines requires extensive environmental reviews by federal and state agencies, as well as consultation with affected property owners along the planned transmission corridor. Transmission lines that are used in interstate commerce are also subject to extensive regulation by the Federal Energy Regulatory Commission (FERC), which requires transmission line owners to offer service on a nondiscriminatory basis to all eligible customers seeking service. FERC is responsible for approving the terms and rates of transmission service, as set forth in the transmission owner's open-access transmission tariff (OATT).

In areas of the country where regional transmission organizations (RTOs) or independent system operators (ISOs) dispatch the grid, the transmission owner turns over operational control of the transmission line to the RTO/ISO, but retains responsibility for maintaining the transmission infrastructure. In areas where RTOs and ISOs do not exist, transmission lines may be controlled by a public utility, a federal power marketing administration, or some other entity.

U.S. Electric Transmission Network



Source: Derived using the EIA U.S. Energy Mapping System Tool

Transmission Planning

Planning for new transmission lines begins after a utility, grid operator, or state regulator determine that a new line is needed. The basis for needing a new line could be for many reasons, including to interconnect new generating resources to the grid, to reduce costly congestion on existing transmission lines that are nearing capacity, or to provide other reliability benefits to the transmission network. As the nation's transmission infrastructure ages, upgrades and replacement of existing transmission assets, as well as capital investment in new infrastructure are necessary to both integrate new distributed energy resources and to respond to shifting demands on the transmission grid.

The *Federal Power Act* gives FERC the authority to regulate the sale and transmission of electricity in interstate commerce. Pursuant to this authority, in 2007, FERC issued a rule (Order No. 890) to reform earlier regulations promoting open-access transmission service. This rule requires that each transmission provider utilize a planning process that must meet nine planning principles, including: coordination; openness; transparency; information exchange; comparability; dispute resolution; regional coordination; economic planning studies; and cost allocation.[1]

However, by 2010, FERC recognized that Order No. 890 did not go far enough in terms of correcting deficiencies with respect to transmission planning processes and cost allocation methods. After extensive industry outreach and the submission of hundreds of comments in response to the proposed rule, Order No. 1000 was issued in 2011.[2] The Order required significant changes to how transmission is planned within and between geographic regions, as well as how transmission costs are allocated to customers. In addition, Order No. 1000 provides non-incumbent transmission developers with the opportunity to compete to build transmission projects within the service territory of incumbent utilities.[3]

With respect to transmission planning, Order No.1000 requires each public utility transmission provider to participate in a regional planning process that satisfies the nine principles contained in Order No. 890 (note: the map below illustrates the boundaries for each of the transmission planning regions.) Additionally, transmission providers in neighboring transmission planning regions are required to coordinate to determine if there are more efficient or cost-effective solutions to address their mutual transmission needs. One of the most promising reforms of Order No. 1000 is the ability for non-incumbent and merchant transmission developers to compete against incumbent utilities to build new projects at potentially lower costs. However, several exceptions in Order No. 1000 allowed for certain types of transmission projects to be exempt from the competitive solicitation process.

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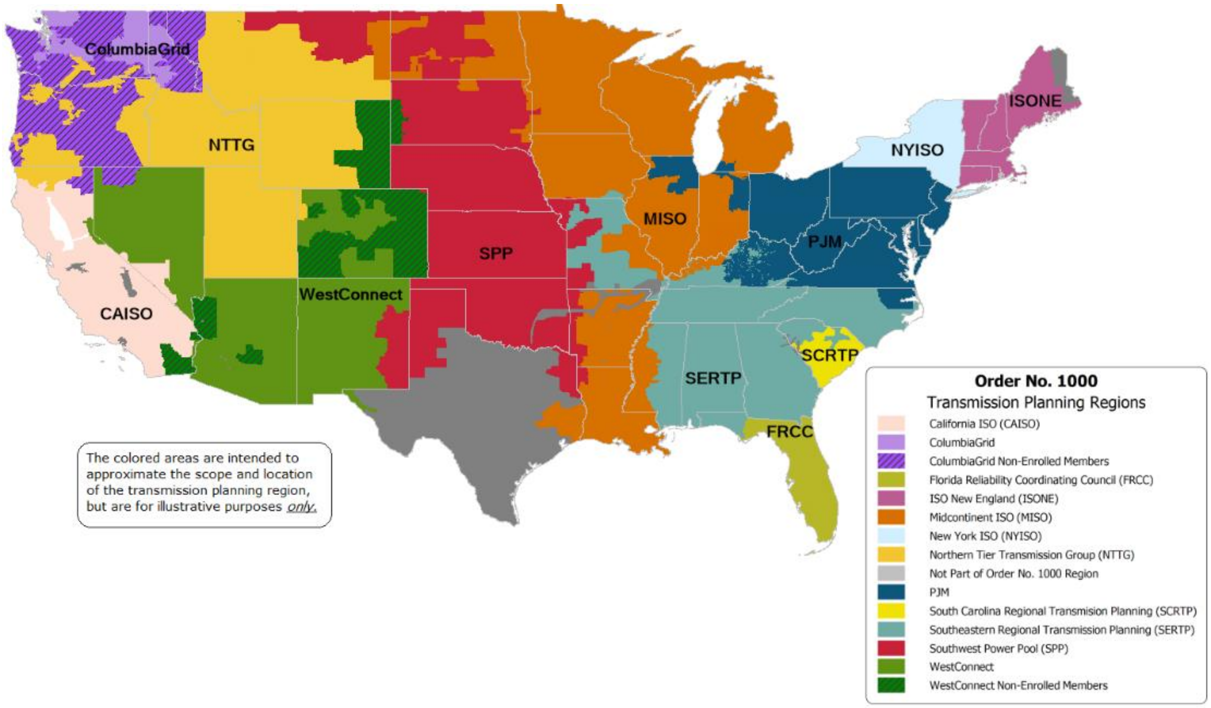
[1] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

[2] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g, and clarification* Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

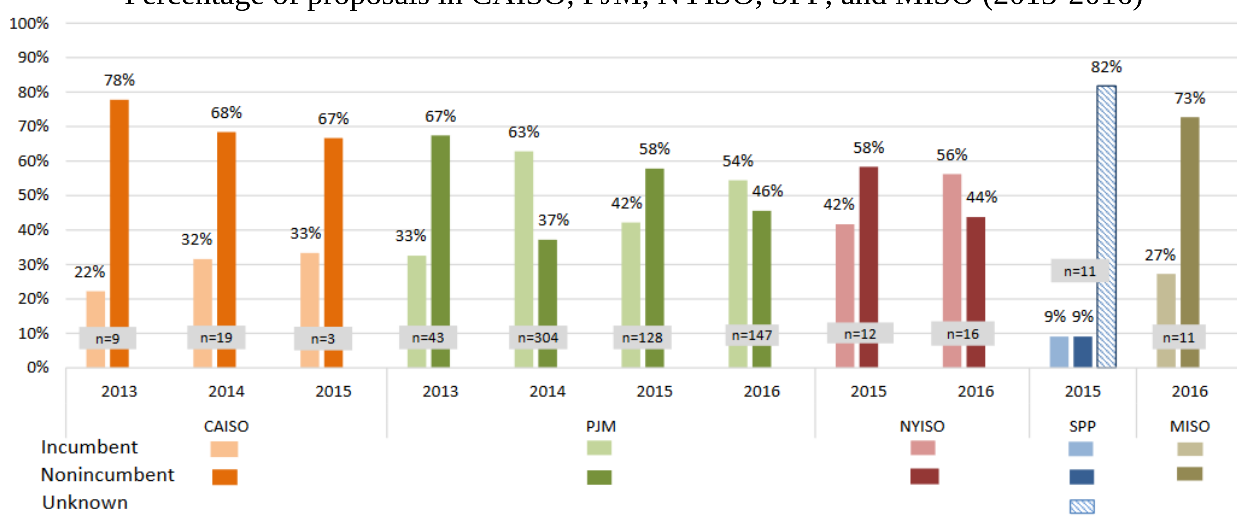
[3] Order No. 1000 defines non-incumbent transmission developer as either: (1) a transmission developer that does not have a retail distribution service territory or footprint; or (2) a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not incumbent for purposes of this project.

FERC Order No. 1000 Transmission Planning Regions



In the nearly seven years that Order No. 1000 has been in effect, concerns have arisen that despite FERC's best intentions, its transmission reforms have not been implemented as anticipated and the rule has not accomplished its goals. While spending on transmission has increased overall, independent transmission developers are particularly concerned with the lack of projects available for competitive bidding. The chart below illustrates that the number of non-incumbent proposals initially exceeded incumbent proposals across all RTOs, however, what is not illustrated is that proposals by non-incumbent transmission developers are rarely awarded the right to ultimately develop the project.

Competitive Proposals by Incumbents vs. Non-incumbents
Percentage of proposals in CAISO, PJM, NYISO, SPP, and MISO (2013-2016)



Source: 2017 FERC Transmission Metrics Staff Report

FERC has reviewed these concerns periodically, convening a technical conference in 2016, and most recently issuing a report on transmission investment patterns to evaluate whether the key goals of Order No. 1000 are being met, and to inform whether additional transmission development is needed in the United States. This report concedes that "it is difficult to assess whether the electric industry is investing in sufficient transmission infrastructure to meet the nation's needs and whether the investments made are more efficient or cost-effective."[4]

Expense of Transmission Infrastructure and Cost Allocation

As increased demands are placed on the grid, a continuous stream of private-sector investment is required to ensure that transmission infrastructure is constructed in an efficient and cost-effective manner. In 2017, according to figures collected by the Edison Electric Institute, investor-owned utilities and independent transmission developers spent an estimated $22.9 billion on new transmission infrastructure. This represents a 10 percent increase over the $20.8 billion spent in 2016, and a 91 percent increase over 2011 levels.[5] Moreover, recent trends and projections indicate that the United States will continue to invest in transmission infrastructure at similar levels into future years.[6] To this end, policies that reduce barriers to transmission development, and reduce regulatory and financial risk will support continued investment in this capital-intensive industry.

Various utility models exist to provide the funding necessary to build transmission infrastructure. In some cases, an incumbent utility may have access to existing capital reserves or can issue bonds to develop new projects, while non-incumbent utilities and merchant developers may have private investors willing to back a project financially and bear any risk. Regardless of the funding source, however, owners of transmission infrastructure ultimately expect to recover their costs through rates. Transmission-owning utilities seeking to place a transmission asset in its rate base will file a rate case with FERC to recover its costs and receive a regulated return on equity (ROE) once the transmission asset is placed in service.[7]

Once a transmission project is determined to be needed, the next question is which customers are responsible for paying for the project. This issue of "cost allocation" is sometimes

[4] Transmission Metrics Staff Report, FERC, October 6, 2017 at p. 6.
[5] Statistical Data on the Electric Power Industry, Edison Electric Institute.
[6] Utilities Continue to Increase Spending on Transmission Infrastructure, U.S. Energy Information Agency (2018); Drivers and Challenges for Transmission Investment, T&D World, K. Knutson, (2017); Transmission Projects: At a Glance at v., Edison Electric Institute, (2016); and Investment Trends and Fundamentals in US Transmission and Electricity Infrastructure, The Brattle Group, Pfeifenberger, Chang, Tsoukalis (2015).
[7] A difficult issue currently before FERC involves the setting of ROEs for interstate transmission projects. Since 2011, FERC has struggled to develop a methodology to calculate a legally-sustainable ROE for existing electric transmission infrastructure. In 2014, FERC issued Opinion No. 531 (*Coakley, Mass. Attorney Gen., et al. v. Bangor Hydro-Elec. Co., et al.*, 147 FERC ¶ 61,234) which attempted to craft a new ROE methodology, but this policy was vacated and remanded to FERC by the U.S. Court of Appeals for the D.C. Circuit in 2017. FERC's response to the Court's decision is pending and a number of ROE-related complaints are currently awaiting action before the Commission. Committee staff has been informed by market participants that in the absence of a clear and stable ratemaking policy, transmission owners, developers, and investors remain cautious due to the regulatory and financial risk associated with building new electric transmission projects. Ultimately, such uncertainty can lead to adverse impacts on customers in the form of increased rates or decreased investment in transmission projects.

more contentious than planning the transmission line itself, as transmission providers, regulators, and grid operators are tasked with deciding who will pay what percentage of the costs.[8] Traditionally, under a "participant funding" model, transmission costs are allocated to customers who agree in advance to bear the costs of the facility. However, under a "beneficiary pays" model, costs are allocated to transmission customers that proportionately benefit from the transmission facilities.

In an attempt to provide greater certainty and consistency to cost allocation practices, Order No. 1000 also included reforms in this area. FERC expressed concern that traditional "participant funding" models for cost allocation could delay or prevent the development of needed transmission lines, particularly those designed to connect renewable generation that is located far from where the electricity would be consumed. Thus, to encourage transmission development, FERC requires that all transmission planning regions adopt some form of regional cost allocation methodology. Order No. 1000 allows flexibility in the cost allocation method so long as the method satisfies several principles, including that costs must be roughly commensurate with benefits, and that customers who do not benefit from a project should not pay for its costs.

Non-Transmission Alternatives

One often overlooked provision in Order No. 1000 is the requirement that a regional transmission plan must consider whether "non-transmission alternatives" can more efficiently or cost-effectively meet the transmission needs of a region. These alternatives are represented by a wide array of resources and technologies, including energy efficiency, demand response, distributed energy resources, microgrids, and energy storage. Additionally, transmission line technologies such as advanced power control, dynamic line rating, and topology optimization can make better use of existing transmission line capacity or reroute power flows on overloaded transmission lines. Ultimately, these alternative resources and technologies have the ability to replace or delay the need to build transmission lines.

Advocates for such resources and technologies argue that the existing transmission planning processes do not adequately consider or promote the incorporation of non-transmission alternatives because Order No. 1000 requires nothing more than a mere consideration of alternatives. There is also some concern that utilities may be reluctant to make investments in non-transmission alternatives precisely because they are less expensive than building transmission infrastructure, which results in less capital costs to include in the utility's rate base, thus yielding a smaller return. Supporters of non-transmission alternatives cite potential savings to consumers by avoiding the expense of building new transmission lines and reducing congestion costs on existing lines. Additionally, non-transmission alternatives typically have either no or minimal environmental impacts when compared to building new transmission infrastructure.

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[8] Electricity Transmission Cost Allocation, by Richard J. Campbell and Adam Vann, CRS Report R41193 (2012).

ISSUES

The following issues may be examined at the hearing:

- Whether transmission planning processes are functioning, as intended, under Order No. 1000;
- The state of competition in transmission infrastructure development;
- Current impediments to developing inter-regional transmission lines;
- Barriers to the broader deployment and utilization of non-transmission alternatives;
- Concerns with existing transmission cost allocation methodologies;
- Whether sufficient transparency into transmission development costs exists.

STAFF CONTACTS

If you have any questions regarding this hearing, please contact Jason Stanek, Annelise Rickert, Wyatt Ellertson, and Mary Martin on the Majority Committee staff at (202) 225-2927, or Rick Kessler on the Minority Committee staff at (202) 225-3641.