

# **Competition for Electric Transmission Projects in the U.S.: FERC Order 1000**

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MARCH 2019

CEEPR WP 2019-004



February 20, 2019

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### ABSTRACT

Historically, high voltage electric transmission facilities in the U.S. have been owned and operated primarily by incumbent utilities subject to state and federal certification, siting, and cost of service regulation. Federal and state regulation of transmission as a natural geographic monopoly continued after vertical and horizontal restructuring, the creation of competitive wholesale electricity markets, and the formation of Independent System Operators (ISO/RTO)<sup>2</sup> to operate these markets and the associated transmission networks. The possibility of extending competition into the development, ownership, and operation of high voltage transmission projects has been a subject of interest to economists and other students of electricity sector restructuring for many years. A theoretical merchant transmission model where transmission investments is supported by tradeable transmission rights whose value reflects the difference in locational prices, attracted a lot of attention and excitement as restructured wholesale electricity markets matured in the 1990s. While this merchant transmission model is elegant, and in some ways, remarkable, when more realistic assumptions are introduced, the attractive attributes of the merchant model are seriously undermined. More importantly, this model has attracted very little interest in practice, especially in the U.S. An alternative competitive model relies on competition among potential incumbent and non-incumbent developers of transmission projects identified through an open solicitation process. Some form of this competitive procurement model has been used for years in Latin America, India and other countries. More recently it has been used selectively in the U.S. prior to Order 1000, in Canada, and in the UK. FERC Order 1000 issued in 2011 has stimulated increased interest in and use of competitive transmission procurement programs in the U.S. This paper discusses the provisions of Order 1000, its application by ISOs, and examines the evidence to date regarding the development and application of the competitive transmission procurement model in the U.S. The limited evidence to date is promising. However, while FERC Orders 890 and 1000 opened up transmission planning processes to non-incumbents and ended the incumbents' federal right of first refusal, diffusion of transparent head-to-head competitive procurement programs has been slow. Refinements can help to secure more of the potential benefits of competition in the future.

Key words: transmission, electricity, competitive procurement, regulation

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<sup>1</sup> Elizabeth and James Killian Professor of Economics, MIT and Research Associate, National Bureau of Economic Research. The views expressed here are my own and do not reflect the views of MIT, the National Bureau of Economic Research or any other entities with which I am affiliated. MIT provided support. A list of my affiliations can be found at <http://economics.mit.edu/files/15081>. I note in particular that I am on the board of directors of Exelon Corporation which has an interest in the issues discussed here. I want to thank Hannas Pfeifenberger and his team at the Brattle Group, Craig Glazer and Suzanne Glatz at PJM, and Mike Kormos formerly at PJM and now at Exelon for assistance with understanding the implementation of Order 1000 and with the data utilized here. I am grateful to Ingo Vogelsang and Mohammad Hesamzadeh for helpful comments on an earlier version of this paper.

<sup>2</sup> There is little difference between an RTO and an ISO. I will simply refer to both as an ISO in this paper. <https://www.ferc.gov/industries/electric/indus-act/rto.asp>.

## I. Introduction and Background

The electric power sector restructuring and competition reforms that have been realized over the last 25+ years in the U.S., Canada, Europe, Latin America, Australia, and elsewhere were built upon a number of institutional assumptions.<sup>3</sup> First, vertically integrated geographical monopolies subject to government regulation or public ownership, embodied a number of inefficiencies. The most serious inefficiencies were associated with the construction, operation, maintenance and retirement of generating facilities. Other inefficiencies arose from the limited array of price and service options available to end-use (retail) customers and inefficient retail rate designs mandated by many regulators.

Second, reformers accepted the view that vertical integration between the generation, distribution, transmission, and retail supply segments was not necessary to supply electricity economically and reliably. The generation segment was viewed as being potentially competitive. So too, the retail supply segment. Accordingly, restructuring involved the separation (structural or functional unbundling) of generation from transmission and distribution, de-concentration of the generation segment through divestiture in some cases, as well as the unbundling of the retail supply segment (financial agreements to support the supply of electricity to end-use customers) from the physical distribution (wires) segment. Competition and market incentives would replace central planning and regulation in the generation segment and the retail supply segment. The restructuring reforms focused on developing and implementing wholesale market designs for

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<sup>3</sup> The restructuring model that I will discuss has not been adopted everywhere in these countries and regions. For example, in the U.S. most of the South and West (except California) continue to rely on regulated vertically integrated firms, though they rely more on PPAs with independent power producers selected through a competitive process, rather than ownership, than was once the case.

energy and ancillary services that would support efficient scheduling and dispatch of generation to balance supply and demand continuously and efficiently, efficient spot market price formation, and efficient entry and exit decisions by owners of generating plants. The retail supply segment was then supported by a competitive wholesale market, unbundling of retail supply, and more recently, the diffusion of advanced metering infrastructure.

Third, it was generally assumed that the physical operation, ownership of, and investment in distribution and transmission networks would continue to be treated as geographic monopolies subject to cost of service regulation, perhaps enhanced with the application of incentive regulation reforms (Joskow, 2014). Finally, policymakers concluded that the operation of and planning for a regional transmission network could be separated from ownership, investment, and maintenance of the physical transmission facilities that compose the transmission network. In restructured regions an independent system operator (ISO) was needed both to perform these functions and to manage wholesale markets for energy and ancillary services in coordination with the reliable operation of the transmission network and the management and pricing of transmission congestion. It was expected that the ISOs would be responsible as well for transmission planning and the assignment of investment responsibility to incumbent transmission owners for designated regional facilities. The ISO itself would own no generation, transmission or distribution assets but rather would act like the conductor of a symphony, making sure that the “decentralized” instruments all played their parts in a way that led to a high-quality symphonic result. This vision has been realized in several regions of the U.S. but certainly not everywhere.

As competitive wholesale market designs and the retail supply industry matured, interest turned to the question of whether decentralized investment in new transmission facilities might be feasible and economical as a complement to or complete substitute for centralized transmission

planning, ownership, regulation of the charges for transmission service. Merchant transmission investment models that anticipated the free entry of developers to own and operate transmission facilities in return for payments reflecting time varying differences in locational prices mediated through the sale of tradeable financial or physical transmission (property) rights, first appeared in the academic literature in the 1990s as restructuring activity gained steam in the U.S. (Hogan 1992, Bushnell and Soft 1996, Chao and Peck 1996). These transmission rights and any revenue associated with their sale would accrue to the owner of the transmission assets and would be the sole source of revenue to compensate the owners for their capital and operating costs. Thus, merchant transmission owners would take on all risks associated with uncertainty over the future value of transmission rights, capital and operating costs, and the profitability of the investment. Traditional centralized transmission planning, investment in designated facilities by the incumbent transmission owners, and the reliance on traditional cost of service regulation, is replaced with decentralized investment decisions driven by market incentives --- locational price differences. The properties of this classical merchant model are indeed very elegant. In 2005, Jean Tirole and I wrote:

“Under a stringent set of assumptions, the merchant investment model has a remarkable set of attributes that appears to solve the natural monopoly problem and the associated [exclusive] need for regulated electric transmission companies,” (Joskow and Tirole 2005, page 233)

In short, if the merchant model could be relied on in practice “... it would lead to the remarkable conclusion that both the generation of electricity and the transmission of electricity could be largely deregulated.” (Joskow and Tirole 2005, page 235)

However, after examining this model under a large set of what we viewed as more realistic assumptions about the attributes of transmission investments, transmission network operating

practices, imperfections in wholesale energy markets, potential strategic behavior by transmission owners of various kinds, and other considerations, we concluded that:

“Unfortunately, these assumptions do not reflect the attributes of the transmission investment opportunities that are likely to be most conducive to merchant investment, the stochastic properties of real transmission networks or widely documented imperfections in wholesale electricity markets.” (Joskow and Tirole 2005, page 235)

“Clearly, policymakers cannot proceed under the assumption that they can avoid dealing with the difficult issues associated with stimulating efficient investment in electric transmission network simply by adopting the merchant transmission model. The merchant model ignores too many important attributes of transmission network and the behavior of transmission owners and system operators” (Joskow and Tirole 2005, page 262).

Policymakers too have been less than enthusiastic about adopting the classical merchant transmission model, despite the widespread reliance on locational marginal pricing (LMP), at the nodal (primarily in the U.S.) or Zonal levels (elsewhere), and the creation of tradeable financial or physical transmission rights assigned initially to transmission owners for sale. The only transmission projects of which I am aware that were developed entirely based on the classical merchant model are the MurrayLink and DirectLink projects in South Australia, and the Montana-Alberta tie-line in the U.S., though the Montana-Alberta line benefited from government financing managed through the Western Area Power Administration.<sup>4</sup> Both of the Australian projects<sup>5</sup> ran into financial difficulties after they were completed and were ultimately converted to regulated

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<sup>4</sup> <https://m-m.net/montana-alberta-tie-line/>; <https://ieeexplore.ieee.org/document/5589741>;  
<https://www.fool.com/investing/general/2013/11/18/montana-alberta-tie-line-merchant-transmission-inv.aspx>.

<sup>5</sup> Basslink is a third “merchant” link between Tasmania and Victoria that was completed in 2006. The link was originally developed by a subsidiary of National Grid PLC following a competitive process run by Hydro-Tasmania. The rights to the link are contracted to Hydro-Tasmania, the government owned electricity company in Tasmania, under a long-term contract with the owner of the link. Pursuant to the long-term contract Hydro-Tasmania pays an annual facility fee to have exclusive access to the link. While Hydro-Tasmania developed the link in anticipation of profitable energy price arbitrage between Tasmania and the South Australian market, the annual facility fee paid to the owner of the link is based on the project’s cost.

projects.<sup>6</sup> The Montana-Alberta line continues to operate though little is known about its behavior and performance.<sup>7</sup> There may be other merchant transmission links of this kind that rely on nodal price differences for revenues that I am not aware of, but it is clear that the classic merchant model has hardly taken the world by storm.<sup>8</sup>

I do not want to revisit or expand on the analysis in our 2005 paper. The theoretical research on the classic merchant model was elegant and useful. For good reasons, it just isn't being applied widely in practice. However, this does not mean that competition cannot be introduced into the development of new transmission projects. An alternative competitive transmission model is available that is more compatible with the technical and institutional attributes of transmission networks in the U.S. ISO regions, regional planning processes and with the regulatory institutions that govern compensation for transmission owners and the design of tariffs for transmission customers. I will call this model the "Competitive Transmission Procurement Model" as it is based on competitive bidding for ISO-designated transmission projects or identified reliability violations or opportunities economically to reduce congestion costs.

In the U.S. context, under this model the construction and operating costs incurred by the winning bidder are still recovered through traditional cost of service regulation, perhaps after performance incentive provisions as well as regional cost allocation and transmission tariff design protocols are applied. Accordingly, this model involves ex ante competition for transmission projects that are regulated ex post. The terms and conditions that the winning bidder agrees to then become a sort of (long term) regulatory contract that defines how compensation for these projects

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<sup>6</sup> <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/directlink-determination-2006-15>; <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/murraylink-determination-2018-23/proposal>.

<sup>7</sup>The owner of the line conducts auctions for transmission right. The line also appears to experience frequent outages. <http://www.oatioasis.com/matl/>

<sup>8</sup> I will discuss briefly below a couple of additional U.S. projects that have components that follow the classical merchant model.



will be determined over time by regulators. The “regulatory contract” here is defined by the selection criteria used by the ISO, performance commitments made by the winning bidder and Federal Energy Regulatory Commission (FERC) cost-of-service recovery rules. For example, the winning bidder could make a firm commitment for construction and maintenance costs of a proposed project, or cap cost recovery (revenues) for some period of time, or propose a sharing mechanisms if costs are lower or higher than specified, or simply agree to be compensated based on traditional cost-of-service regulatory principles (prudent capital costs and reasonable operating costs) without any special performance incentives --- the default --- once they are selected through competitive procurement . I will discuss in more detail how transmission owners are compensated through FERC cost of service regulation further below.

Variants of the competitive procurement model has been used in some countries outside North America for years (Mountain and Carstairs 2018). The model began to evolve slowly and idiosyncratically in the U.S. and in Canada in the early 21<sup>st</sup> century. More recently, the application of this model in the U.S. has now been stimulated by FERC Order 1000 issued in 2011 with compliance dates starting in 2014.<sup>9 10</sup>

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<sup>9</sup> <https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp>.

<sup>10</sup> There is another competitive transmission model that has never drawn much interest in the U.S. This is the “natural gas pipeline” model. In the U.S., new interstate natural gas pipelines and expansions of existing pipelines are developed in the following way. An interstate pipeline developer sees a market opportunity to transport additional natural gas from point A to point B. The developer then proposes a pipeline project to increase gas transportation capacity from point A to point B and seeks long term contractual commitments from shippers to ship their gas from one point to another served by the proposed pipeline. The bids are solicited through a competitive procurement process (open season). If enough shippers (“anchor shippers”) agree to make long term commitments to the project at negotiated prices and price adjustment provisions subject to regulated price caps determined by FERC using traditional cost-of-service principles to make the project financially viable then the developer may proceed. Pipeline capacity that is not sold under long term contracts can be marketed under short-term contracts by the owner at market prices. There is no collective regional planning or approval process for natural gas pipelines as there is for electric transmission facilities. This model has not attracted much interest in the electric power sector in the U.S., though there are a few project developers who have attempted or are attempting to develop projects using this model. See for example, “1,000-MW New York power transmission project signs up anchor customer,” *Megawatt Daily*, November 27, 2018, page 4. In the U.S. electric power sector, this model seems to me to be best suited for DC lines where the “point A to point B” model better reflects the attributes of electric transmission facilities and the transmission networks of which they are components

The paper proceeds as follows. The first section discusses the institutional context in which electric transmission planning, investment, and revenue/cost recovery takes place in the U.S. ISO regions. The next section discusses why competitive procurement can improve the information about costs available to regulators and supplement any performance incentives that are part of standard regulatory protocols. The fourth section discusses FERC Order 1000. The fifth section briefly discusses pre-Order 1000 experience with competitive procurement in the U.S. and other countries. The fifth and sixth sections discuss experience with the implementation of Order 1000 to date, including a discussion of the attributes of proposals submitted and evaluation metrics used in all of the competitive procurements undertaken in the U.S. between 2013 and 2018. The final substantive section discusses lessons learned and opportunities to enhance the value of competitive procurement for transmission in the U.S. There is a short concluding section.

## II. Transmission Planning, Project Selection, and Economic Regulation in the U.S.

Transmission facilities in an ISO region<sup>11</sup> are owned by multiple transmission utilities, primarily incumbents which have been in operation for a century or more. Transmission owners typically also own proximate regulated distribution utilities and may own generating facilities in their region. Transmission owners' facilities typically cover a geographic "footprint" around their distribution utilities and connecting generating facilities which they owned prior to restructuring or continue to own. There are also jointly owned transmission facilities and a few independent transmission utilities that do not own generating or transmission facilities in the region.

The ISO is responsible for managing energy and ancillary service markets, capacity markets where they exist, and the integrated operation of the transmission network in conjunction

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<sup>11</sup><https://www.ferc.gov/industries/electric/indus-act/rto.asp>.

with these markets and various reliability criteria. The ISO does not own any generating, transmission, or distribution facilities. The ISO is the region's transmission operator, operating transmission facilities owned by others.

FERC Order 888 requires that transmission must be at least be “functionally” unbundled from generation and distribution and that all transmitting entities must file Open Access Transmission Tariffs (OATT). All ISO's have filed Open Access Transmission Tariffs (OATT) that have been approved by FERC. The OATT for each ISO includes rules governing the scope and definition of transmission services, ancillary services, congestion management, congestion prices, congestion revenue rights, transmission cost allocation rules,<sup>12</sup> transmission planning procedures, regional transmission tariffs, and anything else related to the operation of, investment in, interconnection of, use of, and planning for the transmission facilities under the ISO's umbrella. The OATT for the New England ISO, for example, is 500 pages in length, including schedules and appendices; there are 45 pages of text just for cost allocation rules for incumbent and non-incumbent transmission owners. PJM's OATT is 3,500- pages and the companion PJM Operating Agreement is over 600 pages long.<sup>13</sup>

ISOs also manage a regional transmission planning process and coordinates their transmission planning with local utility transmission planning and investment in its region. The nature of the interaction between regional planning and local planning varies from ISO to ISO. Pursuant to FERC Order 890, both regional and local transmission planning processes are supposed to be open to all stakeholders, including non-incumbent transmission developers. The regional planning process specifies transmission expansion needs and designates which transmission developer/owner is responsible for building the facilities. Prior to Order 1000,

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<sup>12</sup> FERC Order 1000 requires that regional cost allocation follow a “beneficiary pays” principle.

<sup>13</sup> See FERC orders 888, 889, 890, 1000, [www.ferc.gov](http://www.ferc.gov).

incumbent transmission owners had a right of first refusal to build, own, and operate the designated transmission facilities. Order 1000 ended any (federal) right of first refusal, so non-incumbents may seek to develop projects selected by the ISO through the planning process.

Prior to Order 1000, there was nothing in principle that kept an independent transmission developer from proposing to an ISO to build a project and to recover its costs from the revenues it anticipates receiving from the sales of congestion revenue rights alone. That is, a classical merchant transmission project. Except for a few special cases noted below, the planning, regulatory, and economic environment have made classical merchant investments unattractive.

ISO's are not economic regulators; they do not determine the rules for compensating transmission owners for the use of its facilities or the tariffs that specify how different categories of transmission customers pay for the use of their facilities. This type of economic regulation is the responsibility of FERC.<sup>14</sup> FERC also regulates the ISOs. States retain the authority to review the siting of proposed transmission projects, including environmental impacts and the "need" for the facilities. State certification is required in order for at least a major transmission project to proceed. Certification procedures and requirements vary from state to state.

Transmission owners are compensated through the FERC regulatory process using fairly traditional rate-of-return/cost-of-service procedures. A transmission owner in an ISO (whether an incumbent with distribution and perhaps generating facilities or an independent) must file with FERC the information necessary to form a transmission "revenue requirement." The revenue requirement starts with the specification of a rate base. The rate base is equal to the depreciated original cost of the transmission owner's facilities. The capital cost related portion of the rate base is then the annual depreciation on the rate base plus carrying charges on the rate base. The carrying

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<sup>14</sup> Aside from implementing cost allocation and regional transmission tariff provisions in it OATT.

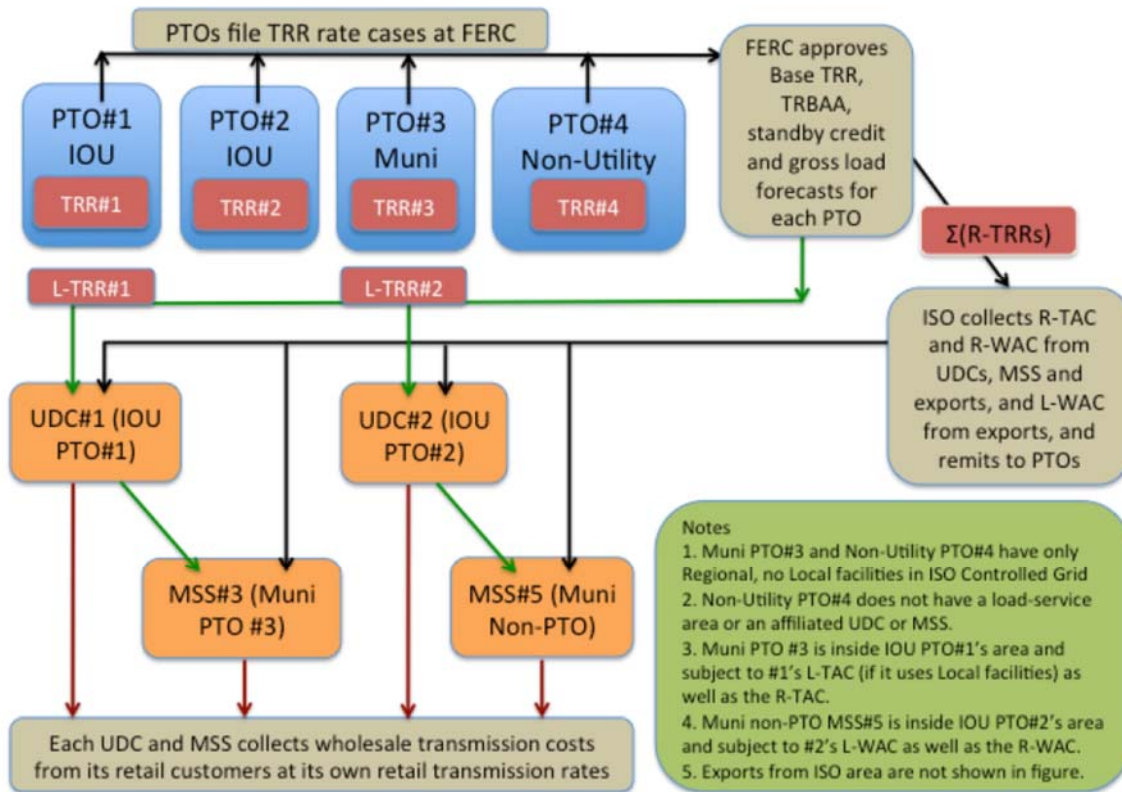
charges are derived by the regulator specifying an allowed rate of return which is multiplied by the rate base. To these two elements of capital cost recovery are added each transmission owner's operating and maintenance costs, fees, and adjustments for taxes. This yields the transmission owner's initial revenue requirement. However, since there are multiple transmission owners within the region and shared regional cost responsibility for some projects some portion of the initial transmission revenue requirement may be allocated to or from other transmission owners. FERC relies on a formula rate approach that adjusts the revenue requirement annually for changes in capital, operating and maintenance costs, allowed rate of return, etc.

The precise cost allocation and tariff structures that determine how transmission owners actually collecting their revenue requirement varies from ISO to ISO. The procedures are fairly complicated in practice, though the basic principles are similar. For example, in the CAISO, the transmission owner's total revenue requirement is divided between a Regional Revenue Requirement (R-TRR) for high voltage facilities and a Local Revenue Requirement (L-TRR) for lower voltage facilities that the transmission owner relies on to serve distribution customers in its area. The CAISO has a tariff to charge transmission customers, primary distribution utilities and exporters, a postage stamp rate based on their load ratios for use of the regional high voltage network. The revenues are then remitted to the transmission owners based on their Regional Revenue Requirements. The transmission owners each have their own FERC approved tariff for recovery of their Local Revenue Requirement from distributors designated to be in their transmission footprints.

I recognize that this cost allocation and cost recovery process is fairly complicated. It is depicted graphically in Figure 1. To complicate matters further there are a variety of grandfathered

transmission contracts and transmission cost allocation agreements that have been carried over from the pre-restructuring/ISO period.

Figure 1



Source: “How Transmission Cost Recovery Through the Transmission Access Charge Works Today,” CAISO, April 12, 2017.

This compensation, cost allocation, and revenue collection process was clearly developed initially with incumbent transmission owners whose facilities primarily serve their local distribution companies in mind. How does it work for a non-incumbent independent transmission developer/owner no distribution assets in the area? The process would be similar. The

transmission owner would still file with FERC for a transmission revenue requirement which would include any incentive arrangements it has agreed to through a competitive procurement process and would be adjusted by formula annually. The ISO would then apply its cost allocation rules to the transmission owner's facilities to determine how the costs would be recovered through a regional ISO tariff, the tariff of a transmission owner with local facilities, or directly from transmission customers. The revenues are then remitted back to the independent transmission owner.

As noted, FERC is the economic regulator for high voltage transmission facilities operated by the ISO. In principle it applies prudent investment and reasonable cost standards to the capital and operating costs presented to it by a transmission owner. Costs that are determined to be imprudent or unreasonable can be disallowed and excluded from the revenue requirement. However, at best, such exclusions are rare. Nor does FERC apply conventional incentive/performance based regulation mechanisms (Joskow 2014, Vogelsang 2001, 2018). For all intents and purposes the FERC regulatory process is a model of cost pass-through regulation with little scrutiny of costs. FERC does offer financial incentives for transmission investments meeting several specified goals, but these are different from traditional incentive/performance based regulatory mechanisms.

According to FERC, the following types of incentives are available:

“The Energy Policy Act of 2005 directed the Commission to develop incentive-based rate treatments for transmission of electric energy in interstate commerce, adding a new section 219 to the Federal Power Act. The rule implemented this new statutory directive through the following incentive-based rate treatments:

- a. Incentive rates of return on equity for new investment by public utilities (both traditional utilities and stand-alone transmission companies, or transcos);
- b. Full recovery of prudently incurred construction work in progress;
- c. Full recovery of prudently incurred pre-operations costs;

- d. Full recovery of prudently incurred costs of abandoned facilities;
- e. Use of hypothetical capital structures;
- f. Accumulated deferred income taxes for transcos;
- g. Adjustments to book value for transco sales/purchases;
- h. Accelerated depreciation;
- i. Deferred cost recovery for utilities with retail rate freezes; and
- j. A higher rate of return on equity for utilities that join and/or continue to be members of transmission organizations, such as (but not limited to) regional transmission organizations and independent system operators.

All rates approved under the rules are subject to Federal Power Act rate filing standards. The rule allows utilities on a case-by-case basis to select and justify the package of incentives needed to support new investment. Additionally, the rule provides expedited procedures for the approval of incentives to provide utilities greater regulatory certainty and facilitate the financing of projects. The rule became effective on September 29, 2006.”<sup>15</sup>

Aside perhaps from removing the disincentive a regulated utility might have to continue to operate a project which should be abandoned so as to avoid having the undepreciated costs stranded, most of these incentives are either incentives to invest in transmission generally or to join an RTO/ISO or to encourage the creation of independent transmission companies. They are not the kind of cost control and operating performance incentives that would normally be an important part of a performance-based incentive regulation tool kit. Rather, the incentive scheme is basically cost of service regulation with higher returns to take certain actions that advance FERC policies --- especially encouraging investing in transmission by offering higher returns than the standard pro-forma rate of return and higher cash flows by doing so and encouraging independent transmission companies. FERC has been uninterested in applying more traditional incentive regulation mechanisms.

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<sup>15</sup> <https://www.ferc.gov/industries/electric/indus-act/trans-invest.asp>



### III. FERC Order 1000

FERC Order 1000 was issued on July 21, 2011 and became effective on October 11, 2011. This Order (or technically “Rule”) establishes revised obligations regarding “Transmission Planning and Cost Allocation by Transmission Owning and Operating Utilities.” The Rule builds on earlier transmission reforms, especially Order 890, related to open transmission planning processes and cost allocation methods.

Regarding transmission planning reforms, the new Rule specifies that:<sup>16</sup>

- a. Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.
- b. Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.
- c. Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.
- d. The Rule specifies 15 regional transmission planning areas, with each RTO/ISO a separate planning area. Transmission utilities that are not members of an RTO/ISO were assigned to a regional planning area as well.

Regarding cost allocation reforms, the rule provides that:

- a. Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost allocation principles.
- b. Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective. The method must satisfy six similar interregional cost allocation principles.

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<sup>16</sup> This description is taken directly from <https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp?csrt=16071104753993213338> which also contain a map of the transmission planning regions.

- c. Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method.<sup>17</sup>

Order 1000 also contains reforms supporting the participation of non-incumbent transmission developers in regional transmission planning and the development of new transmission lines meeting certain (vague) criteria. These reforms are of most interest to me here.

In particular,

- a. Public utility transmission providers must remove from Commission-approved tariffs and agreements a federal right of first refusal for a transmission facility selected in a regional transmission plan for purposes of cost allocation, subject to four limitations:
  - o This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.
  - o *This allows, but does not require, public utility transmission providers in a transmission planning region to use competitive bidding to solicit transmission projects or project developers.*
  - o Nothing in this requirement affects state or local laws or regulations regarding the construction of transmission facilities, including but not limited to authority over siting or permitting of transmission facilities.
- b. The rule recognizes that incumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations. The rule requires each public utility transmission provider to amend its tariff to require reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility require evaluation of alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers can meet reliability needs or service obligations.

The affected transmission utilities were given 12 months to make a compliance filing (18 months for interregional cost allocation methods). With the back and forth between the regions, FERC and the courts, the completion of the compliance process took more time than this. Most regions completed the compliance process in 2014, 2015 and 2016.<sup>18</sup> Of most interest to me here are the reforms governing non-incumbent transmission developers and the use of the option of

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<sup>17</sup> Participant funding refers to merchant projects that are compensated with transmission congestion revenues, the sale of transmission congestion revenue right, or contracts with specific transmission users. The developers of participant funded projects bear the full market risk of these projects. See FERC Policy Statement on participant funded transmission projects. [www.ferc.gov/whats-new/comm-meet/2013/011713/E-2.pdf](http://www.ferc.gov/whats-new/comm-meet/2013/011713/E-2.pdf) .

<sup>18</sup> <https://www.ferc.gov/industries/electric/indus-act/trans-plan/regional.asp?csrt=319600170759416567>

adopting a competitive bidding process that includes both incumbent and non-incumbent transmission developers. With or without a formal competitive solicitation process, non-incumbent utilities can participate in and, in principle, be selected to develop a project through the open regional transmission planning process. FERC seems to place a lot of faith in this open competition with ideas planning process. As discussed below, there is little evidence to support this view. The cost allocation rules are important as well, since the cost allocation rules ultimately define how transmission developers are paid and who ultimately pays for the associated transmission costs over the life of the assets. Order 1000 requires that regional cost allocation rules follow “beneficiaries pay” principles.

#### IV. Why Competitive Procurement?

The reliance on traditional cost of service regulation, absent performance incentives, to determine the “revenue requirements” that a transmission owner may recover is subject to the reasonable criticism that it provides poor incentives for controlling costs. As already noted, FERC does not have a well-developed process to scrutinize the costs presented to it for inclusion in the transmission owners’ revenue requirements or a history of disallowing unreasonable costs. To a first approximation FERC cost of service regulation is cost pass through regulation with little scrutiny of costs. While third parties, including state public utility commissions, may challenge the costs incurred by a transmission owner or its operating performance pursuant to “prudence” or “just and reasonable” criteria, these criteria are rather vague and applied only in exceptional circumstances. In principle, a state regulator could file a complaint with FERC when the transmission owner seeks cost recovery from FERC if it believes that the costs incurred were excessive. However, I am not aware of any such cases. The ISO’s regional transmission planning process may provide some natural cost containment features since cost estimates are

one factor that will affect which projects are included in the regional transmission expansion plan. However, as noted by Pfeifenberger et. al (2018), roughly half of the costs of transmission investment incurred between 2013 and 2017 across ISOs, are not scrutinized in any detail by the ISO or the regional stakeholder planning process. And realized costs may differ significantly from cost estimates. While FERC has accepted, in principle, the value of performance based regulatory mechanisms and the associated rewards and penalties such as those discussed in Joskow (2014), as notes, FERC transmission incentives have focused on providing generous cost recovery rules for transmission owners to make adding transmission capacity financially attractive and for meeting certain criteria reflecting its policy goals (e.g. independent transmission company, merchant transmission, new technology).<sup>19</sup> FERC Order 679 expressed FERC's continued general interest in performance-based incentives and competitive bidding but required neither as part of its transmission incentive portfolio. Indeed, Order 679 reflects considerable skepticism about the importance of performance-based incentives and, perhaps more importantly, the ability to apply classic performance-based regulatory mechanisms to transmission in the U.S. given the structure of the transmission industry (e.g balkanized transmission ownership, ISOs with no assets, continued vertical integration and state regulation of bundled transmission costs in a large fraction of the country, private, public and municipal ownership with different regulatory regimes).

The structure of the high voltage transmission sector in the U.S. and the associated regulatory institutions are indeed a barrier to applying performance-based regulatory mechanisms

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<sup>19</sup> FERC's policies on incentives for transmission owners were first articulated in FERC Order No. 679 (July 20, 2006). The types of incentives FERC has focused on are described in paragraphs 84-263 of Order No. 679. Paragraphs 263-279 discuss performance-based ratemaking and competitive bidding with little enthusiasm and little more than "we will continue to think about it and support its development." <http://www.ferc.gov/whats-new/comm-meet/072006/E-3.pdf>. Little if anything progressed on this front prior to the competitive bidding provisions of Order 1000.

similar to those that have been applied in other countries. Joskow (2014, pp. 326-331) provides example of the application of incentive regulatory mechanisms in the UK. However, at that time there was a single monopoly integrated independent transmission grid owner and operator to which incentive regulation mechanisms could be applied by a single regulator. This is not the case in the U.S. In the U.S. there are many transmission owners that own pieces of the regional transmission system. An ISO owns no transmission assets and does not develop or maintain transmission projects. It is not clear how one would apply classical incentive regulation mechanism to multiple owners of assets that compose a single regional grid or to the ISO which has no assets and is not really owned by anyone. The ISO could file complaints with FERC about excessive costs or poor performance by transmission owners in its region, but I am not aware that this has ever happened. FERC also has no authority to review transmission siting and environmental impacts or issue certificates of need. FERC's jurisdiction also extends only to investor-owned transmission facilities.

Laffont and Tirole (1993) have derived a variety of (second-best) efficient “incentive regulatory mechanisms” aimed at solving two fundamental problems that regulators must confront: (a) prices/revenues that exceed what is necessary to induce the developer to invest result from imperfect and asymmetric information about the firm's true costs. and (b) excessive costs result from inefficiently low firm managerial effort, or moral hazard. Very simply, this is the case because regulators have imperfect knowledge about the firm's costs while the regulated firm knows its costs and can exploit this information asymmetry to its advantage. Regulators also cannot observe the firm's “effort” (managerial performance), and other things equal, managers would prefer exerting less effort to more effort. The Laffont-Tirole procurement and regulatory mechanisms can be applied both to regulation of legal monopolies, like U.S. utilities in the U.S.,

and to the design of procurement auctions and associated contracts for everything from firms to airplane to transmission links. More generally, “competition for the market” has long been viewed as a potential substitute for traditional commission regulation of legal monopolies (Demsetz 1968). The idea is that if there is a natural monopoly supply situation we can satisfy the constraint of having one firm in the market by putting the monopoly franchise out for competitive bids and then rely on a long-term commercial incentive contract to manage the relationship between the firm and consumers, rather than relying on commission regulation. However, the likely practical performance of competitive bidding as a governance arrangement for long-lived sunk assets with attributes like those of electricity, gas, cable TV, railroad infrastructure, etc. has been subject to a great deal of criticism (e.g. Williamson 1976, Goldberg 1976). The problem is that the long-term contracts needed to govern the relationship with the winning bidders and consumers involve long-lived sunk investments, must deal with a large number of contingencies, are inherently incomplete and subject to contractual breakdowns of various kinds. The argument is that over time, these contractual breakdowns become so severe that an administrative agency (i.e. a regulatory agency of some kind) must be created to manage “fairly” a dynamic contractual relationship as relevant contingencies emerge over time. After all, most of the electric, gas, telephone, street railway companies, etc., started out life through a competitive franchise bidding process. Their franchise contracts broke down and they became subject to commission regulation, effectively substituting a long-term regulatory contract for a long-term commercial contract.

From the perspective of Laffont and Tirole’s incentive mechanism paradigm, competitive auctions or competition for the market, can be viewed as a complement or substitute for optimal regulation (Laffont and Tirole 1993, Chapter 8). Auctioning contracts reduces the regulators uncertainty about the firm’s true costs, reducing the costs of asymmetric information (excessive

rents to the firms). An incentive contract is still needed to deal with moral hazard, but the terms and conditions of the contract can be specified by the regulator or made a component of the competitive bidding program. In the context of FERC regulation of transmission, I view competitive bidding as a partial substitute for the absence of performance-based regulatory mechanisms. Because FERC is ultimately the regulator of projects and associated compensation arrangements agreed to with the winning bidder, it already is in the position to adapt the terms and conditions of the attributes of the winning bid to deal with unanticipated contingencies, holdups, bankruptcies, or other potential contractual breakdowns over time.

The analogy to competition for the market or franchise bidding should not be taken too far. As we shall see, only small segments of large transmission networks are being put out for competitive bidding. Contractual breakdown would not be too costly in this situation anyway and a backstop process for designating incumbents to invest in needed facilities and for compensating them already exists. That is, FERC provides a default regulatory contract if the commercial contract fails, the firm performs poorly or goes bankrupt. As noted earlier in the paper, the two merchant links in Australia did go bankrupt and reverted to being regulated transmission links fairly smoothly.

According, competitive procurement of the type allowed by FERC Order 1000 can be viewed constructively as a complement to FERC regulation by providing ISOs and FERC with more information about the costs of building and operating new transmission facilities and potentially introducing performance incentives over the capital costs, operating costs, performance of new transmission facilities. This view is reflected very briefly in Order 679.<sup>20</sup>

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<sup>20</sup> Reference Paragraph in Order 697.

In this context, a competitive bidding program for new transmission links allows competing transmission developers effectively to propose alternative regulatory cost recovery formulas for determining annual revenue requirements. For example, bidders might agree to a cap on revenue requirements for some number of years after the transmission facility is completed, or agree to alternative annual adjustment formula like CPI-x used in the UK and Latin America, or agree to cap construction costs allowed in determining the facility's revenue requirements, or a sharing mechanism, etc. I will refer to these kinds of provisions effectively as "cost containment" provisions below. Of course, bidders could simply propose to receive traditional FERC cost of service recovery, expecting to win a competitive solicitation based on a project that has the lowest estimated costs, and this is how the vast majority of transmission costs are recovered. This might be the case for example where the lowest cost project requires enhancements to existing facilities (e.g. reconductoring) which can be accomplished most economically by the incumbent. Or it might be the case where there is a lot of uncertainty associated with a project due to permitting challenges.

Note, that in this discussion, I have assumed that the burden of evaluating cost estimates, trading off alternative cost commitments, risks, etc. on the ISO when it selects projects through competitive bidding. Since the ISO is choosing the projects and Order 1000 places the burden on it to choose the most efficient or cost-effective projects identified in the regional transmission plan at first blush this makes sense. However, ISO's are not economic regulators in the traditional sense and have neither the expertise nor authority to adopt transmission ratemaking procedures. FERC is the economic regulator of transmission costs, incentives and transmission rates and regulates the ISOs. There seems to be an institutional gap here that needs to be filled.



#### IV. Competitive Procurement for Transmission Projects Before Order 1000

##### a. Other Countries

Before proceeding to discuss the experience with competitive procurement in the U.S. following Order 1000 it is useful to recognize that competitive procurement for specific transmission projects is not a new idea. As noted, competitive procurement of transmission of projects has been used in other countries for years.

Argentina initiated a competitive procurement auction for the fourth Camahueto to Buenos Aires line (1700 Mw) in 1994 and a developer was selected in 1997. Much has been written about this competitive procurement process (Galetovic and Inostroza 2007, Littlechild and Skirk 2008a,b,c,d; Littlechild and Ponzano 2008). Argentina subsequently reformed its electricity law again and continues to rely on competitive procurement for transmission (J.P.H. Sijm 2015). Brazil (extensively), Peru, Chile, the UK, and India have also used competitive procurement (competitive tenders) for long term contracts to support investment in new transmission facilities meeting a variety of criteria (Mountain and Carstairs 2018).

Alberta began to consider a competitive solicitation process for major regional transmission projects in 2011 and approved the details of the process in 2012 and 2013.<sup>21</sup> The Fort McMurray West project (500 kV) was selected through this process, though final approvals took quite a bit of time. The project is expected to be completed in 2019. The project is supported with a 40-year contract negotiated between the developer and the Alberta ISO.<sup>22</sup>

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<sup>21</sup> <https://www.aeso.ca/grid/competitive-process/> .

<sup>22</sup> <https://www.aeso.ca/grid/competitive-process/fort-mcmurray-west-500-kv-transmission-project/>

b. The U.S.

The Long Island Power Authority (LIPA) has used a competitive procurement mechanism to select transmission interconnectors between Long Island and New England and between Long Island and PJM.<sup>23</sup> The New York Power Authority (NYPA) selected a transmission project (the Hudson Project completed in 2013) to connect New York City and PJM. These three projects are “participant funded” and are supported by long term contracts with either buyers (LIPA and NYPA) , or in the case of Hudson, a large fraction of, the line’s capacity. Neither the details of these contracts nor the details of the competitive procurement process and evaluation criteria are publicly available. The Hudson arrangement is interesting because a portion of the capacity was retained by the developer for “merchant” sales of point to point transmission capacity on the line.<sup>24</sup>

In 2009, Linden VFT, LLC, an affiliate of GE Energy Financial Services (“GE EFS”), installed a Variable Frequency Transformer facility (“VFT”) connected to the existing Linden, New Jersey, to Brooklyn, N.Y. line. This project created an additional 315 megawatts (“MWs”) of bi-directional electricity transfer capability between the control area of the PJM Interconnection, LLC (“PJM”) and the New York Independent System Operator Inc. (“NYISO”) Zone J, on an existing regulated transmission line between New Jersey and New York City. The additional capacity is participant funded and is a classic merchant project similar to the financing and contracting for new natural gas lines. Linden VFT holds open seasons where the Transmission Scheduling Rights (“TSRs”) for the project’s electric transfer capacity are auctioned to market participants, as anticipated by the Merchant model.<sup>25</sup> While Linden VFT is an expansion of an existing regulated

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<sup>23</sup> The Neptune (2007) interconnector between LIPA and PJM. The Cross-Sound interconnector between New England and Long Island (2005).

<sup>24</sup> Unfortunately, the Hudson line incurred a series of serious system faults beginning in 2016. The developer defaulted on its loans which led to renegotiation with the New York Power Authority, lenders, and insurers. The entire cable is being replaced and new contractual arrangements negotiated.

<sup>25</sup> In April and May of 2018, Linden VFT, LLC (an affiliate of General Electric Company) will conduct an open solicitation to sell 315 MWs of transmission scheduling rights (“TSRs”) pertaining to its Linden Variable Frequency

link and did not have to confront the licensing, cost and construction challenges associated with an entirely new underwater link, it does clearly embody the classic merchant model.

Interconnection between PJM and New York City/Long Island and between New England and New York/Long Island are particularly attractive for supporting a merchant model as energy and capacity prices in New York City/Long Island are on average much higher than in the surrounding areas due to transmission congestion and special reliability rules applicable to New York City.<sup>26</sup> If the classical merchant model can work anywhere it is here.

The Public Utility Commission of Texas approved a competitive procurement process in 2008 to select developers of about 2,400 miles of new transmission lines to relieve congestion between Competitive Renewable Energy Zones (CREZ) (wind) and load in ERCOT, increasing transfer capacity by about 18,500 Mw. <sup>27</sup> The selection criteria and selection rationale for the chosen projects are not available to me. However, these projects appear to be traditional cost-of-service regulated projects whose costs are ultimately recovered by retail consumers through their “wires” charges. Nine different transmission service providers, a mix of Texas utility incumbents and non-incumbents, were selected to build the CRZ facilities, at an estimated 2008 cost of \$4.93 billion and a target completion date 2013. The projects were completed in January 2014. The final cost of the projects was about \$7 billion.<sup>28</sup>

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Transformer Project (“Linden VFT”). The TSRs will be sold for a term beginning June 1, 2019. The term length of the TSR purchase agreements will be specified by the bidder, with a minimum term of one year. The Linden VFT TSRs allow for the withdrawal (or injection) of power at the Linden VFT switching station near Linden, NJ and the injection (or withdrawal) of power near the Goethals Substation in the Borough of Staten Island, New York City. As a result, the TSRs can be used to sell energy and capacity sourced in PJM into New York ISO (“NYISO”), as well as energy and capacity sourced in NYISO into PJM. This project is the closest to a classic merchant project that I have found in the U.S.

<sup>26</sup> On the other hand, all of these projects had to confront technical reliability issues associated with connecting ISO-New England and PJM with New York. The two LIPA projects are DC links. The Linden VHF facility represents an investment that allowed the existing link to operate at a higher capacity by resolving reliability issues.

<sup>27</sup> ERCOT, the ISO that covers most of Texas, is not subject to FERC jurisdiction.

<sup>28</sup> Warren Lasher, “The Competitive Renewable Energy Zones Process” (presentation), ERCOT, August 11, 2014. <https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=2ahUKewjgsr6VvJ3gAhXGnuAKHZpiAGgQFjAAegQICRAC&url=https%3A%2F%2Fwww.energy.gov%2Fsites%2Fprod%2Ffile>

California adopted a competitive procurement process for certain transmission project in 2010 and the process was then adjusted to conform to Order 1000. These projects will be discussed further below.

## V. Early Experience with Order 1000 Competitive Procurement Programs: Overview<sup>29</sup>

As of 2018, five of the six RTO/ISOs subject to FERC jurisdiction have adopted and implemented competitive solicitation programs of one kind or another (New York ISO (NYISO), California ISO (CAISO), PJM, SPP, and MISO). In principle, ISO-NE has agreed to implement competitive procurement for projects that meet certain criteria.<sup>30</sup> However, its 2017 Regional System Plan states no projects have met its criteria for competitive procurement:

“Since the effective date of the order, the ISO has completed several area needs assessments or has conducted an update to an already completed needs assessment. [footnote omitted] The results of all the needs assessments show that that time-sensitive and a few non-time-sensitive needs exist. [footnote omitted] Thus, the solutions study process has been used first to solve the time-sensitive needs, and the Competitive Solutions Process for the few non-time-sensitive needs has been placed on hold until the time-sensitive needs are addressed through the solutions study process. [footnote omitted] After the solutions have been identified for the time-sensitive needs, the ISO will begin a new needs assessment, which will include the preferred solutions for the time-sensitive needs and identify any remaining needs. [footnote omitted] The ISO will continue to review the implementation of the competitive process in New England and across the country.”<sup>31</sup>

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[s%2F2014%2F08%2Ff18%2Fc\\_lasher\\_qer\\_santafe\\_presentation.pdf&usg=AOvVaw1M34UYAK3OITjTvnQH1P](https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=2ahUKEwillaiTv53gAhWw11kKHT_5C9kQFjAAegQIChAC&url=https%3A%2F%2Fcleanenergysolutions.org%2Fsites%2Fdefault%2Ffiles%2Fdocuments%2Fjeff-billo_webinar-ercot-crez-process.pdf&usg=AOvVaw0iscL8rx-8fSIFt_OMT0T3)  
[MO](https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=2ahUKEwillaiTv53gAhWw11kKHT_5C9kQFjAAegQIChAC&url=https%3A%2F%2Fcleanenergysolutions.org%2Fsites%2Fdefault%2Ffiles%2Fdocuments%2Fjeff-billo_webinar-ercot-crez-process.pdf&usg=AOvVaw0iscL8rx-8fSIFt_OMT0T3). Public Utility Commission of Texas, “Scope of Competition in Electricity Markets,” January 2009. See also, Electric Transmission Texas, <http://www.ettexas.com/Projects/TexasCrez> and [https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=2ahUKEwillaiTv53gAhWw11kKHT\\_5C9kQFjAAegQIChAC&url=https%3A%2F%2Fcleanenergysolutions.org%2Fsites%2Fdefault%2Ffiles%2Fdocuments%2Fjeff-billo\\_webinar-ercot-crez-process.pdf&usg=AOvVaw0iscL8rx-8fSIFt\\_OMT0T3](https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=2ahUKEwillaiTv53gAhWw11kKHT_5C9kQFjAAegQIChAC&url=https%3A%2F%2Fcleanenergysolutions.org%2Fsites%2Fdefault%2Ffiles%2Fdocuments%2Fjeff-billo_webinar-ercot-crez-process.pdf&usg=AOvVaw0iscL8rx-8fSIFt_OMT0T3).

<sup>29</sup> See the Data Appendix for a description of the process that I used to collect information for each ISO.

<sup>30</sup>The New England ISO’s web site mentions a competitive procurement process and RFPs. However, according to its 2017 Regional System Plan, the ISO’s transmission planning process has not yet identified a project that meets its criteria for making it a competitive project and issuing an RFP: <https://www.iso-ne.com/system-planning/system-plans-studies/rsp/>, pages 68-70. . This is not because no transmission projects have been authorized by the New England ISO. In 2017, for example, ISO-NE authorized 23 transmission projects to be developed by incumbent utilities and subject to traditional FERC regulation. [https://www.iso-ne.com/static-assets/documents/2018/01/2017\\_prior\\_year\\_projects\\_section\\_4j\\_iii.pdf](https://www.iso-ne.com/static-assets/documents/2018/01/2017_prior_year_projects_section_4j_iii.pdf).

<sup>31</sup> ISO-NE 2017 Regional System Plan, page 69. [https://www.iso-ne.com/static-assets/documents/2017/11/rsp17\\_final.docx](https://www.iso-ne.com/static-assets/documents/2017/11/rsp17_final.docx)

At this relatively early stage it is important to recognize that the ISOs have adopted a variety of policies that significantly limit the projects that are solicited through a formal open competitive procurement. Factors that determine whether or not a project is open to competitive procurement include time until project is needed, subject to regional or local reliability criteria, type of project (reliability, public interest, market efficiency), upgrades of existing facilities, voltage, type of equipment (e.g. substations) and other considerations that are not particularly transparent.. As emphasized in a recent study by Pfeifenberger, *et. al.*, (2018), meaningful competitive solicitations account for a tiny fraction of transmission projects approved since Order 1000 went into effect. The ISOs have also adopted different approaches toward integrating the transmission planning process with the competitive solicitation process. CAISO, MISO, and SPP identify specific projects that they conclude are needed to meet reliability, market efficiency, and public policy needs through the regional transmission planning process. A competitive solicitation and associated RFP is then developed for a small set of these projects meeting ISO specified criteria. While specific projects are put out for competitive bidding, the details of the design of the project may vary significantly from one competitive proposal to another. FERC staff refer to this as a competitive bidding model (FERC 2017).

PJM and NYISO use the transmission planning process to identify specific reliability, market efficiency, and public policy “needs.” The competitive process then allows bidders to specify proposed transmission projects that meet these needs. FERC staff refer to this as a “sponsorship” model. Arguably, this gives the competitive procurement process an even greater opportunity to attract more innovative and cost-effective solutions to a transmission need that might not have been identified through a specific project first identified by the ISO and then subject to competitive

procurement. However, NYISO and PJM have applied the sponsorship model quite differently as well. In principle, the PJM Regional Transmission Expansion (RTEP) planning process and the associated competitive “windows” provides a much larger number of opportunities for incumbents and non-incumbents to compete for reliability and market efficiency projects. As discussed further in the next section, between 2013 and 2017 about 800 proposals were received in response to 16 competitive windows that were opened.<sup>32</sup> About 140 project selections have been made through this process. However, only three went to non-incumbents. The NYISO has designated only two large “public interest” needs for which competitive solicitations have been initiated. PJM also has implemented a competitive process for “market efficiency” projects while NYISO has not.<sup>33</sup>

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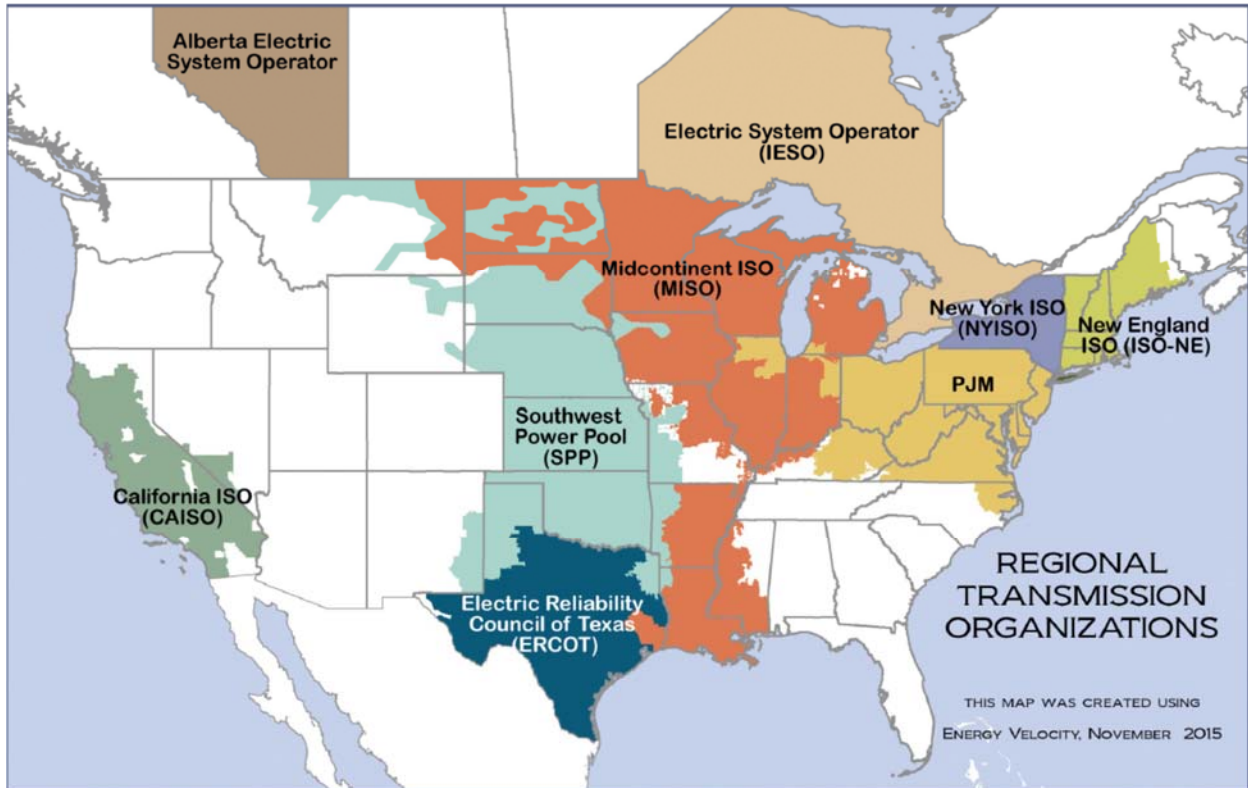
<sup>32</sup> Another 7 proposals were submitted in a short-term window opened in 2018 but selections have not been announced as this is written. A 2018/19 long-term window is still open as this is written.

<sup>33</sup> PJM is a multi-state RTO and apparently has left it to transmission companies to work with each state to identify public policy needs.

## V. Experience in Each ISO<sup>34 35</sup>

Figure 2 is a map of the U.S. ISOs

Figure 2



Source: FERC, <https://www.ferc.gov/industries/electric/indus-act/rto.asp>

### a. CAISO

I found ten projects selected through competitive procurement by the CAISO between 2013 and 2016.<sup>36 37</sup> FERC (2017, page 22) indicates that there have been 9 RFPs. The Brattle study

<sup>34</sup> ISO New England has filed with FERC for a competitive procurement program as part of its Order 1000 compliance but has issued no RFPs to date. <https://www.iso-ne.com/system-planning/transmission-planning/competitive-transmission-projects>. See text and footnotes *infra*.

<sup>35</sup> SPP issued an RFP for one project and went through a competitive solicitation and awarded the project to one of the proposed sponsors. However, the project was subsequently cancelled by the regional planning organization due to declining load.

<sup>36</sup> <http://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx> ; <http://www.caiso.com/planning/Pages/TransmissionPlanning/2013-2014TransmissionPlanningProcess.aspx>.

<sup>37</sup> One project had only one applicant

identified 10 competitive projects (Pfeifenberger 2018). The 10 CAISO projects that I found match those in the Brattle study.

I was able to find no additional competitive solicitations by CAISO beyond those initiated based on CAISO's 2013-2014 resource planning process. While the 2014-2015 regional planning process did authorize 8 new projects, none qualified for competitive procurement. The inclusion criteria are described as follows:

“Where the ISO selects a regional transmission solution to meet an identified need in one of the three aforementioned categories that constitutes an upgrade to or addition on an existing participating transmission owner facility, the construction or ownership of facilities on a participating transmission owner's right-of-way, or the construction or ownership of facilities within an existing participating transmission owner's substation, construction and ownership responsibility for the applicable upgrade or addition lies with the applicable participating transmission owner.”<sup>38</sup>

The same result appears to have emerged from subsequent transmission plan updates. The 2015-2016 CAISO regional plan identified 14 new regional. None qualified for competitive solicitation. The 2016-2017 CAISO regional transmission plan authorized two new projects neither of which met the criteria for competitive solicitation. The 2017-2018 regional transmission plan identified 17 new projects, none of which qualified for competitive procurement based on these criteria. It is unclear to me whether the CAISO continues to be interested in competitive procurement for transmission. Accordingly, we examine the 10 projects authorized for competitive solicitation in the 2013-2014 transmission plan to better understand the attributes of the procurement and evaluation process.

The CAISO competitive procurement process is quite transparent and well-documented, from the identification of the project to the evaluation criteria and ultimately to the evaluation and selection of the winning proposal. A common set of evaluation criteria and a common evaluation

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<sup>38</sup> [www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf](http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf).



template was applied to all ten project solicitations. This makes the solicitation and evaluation process relatively straightforward to review. The projects that are selected to be included in its competitive procurement process are developed through an annual open transmission planning process. Potential developers responding to the RFP must submit a long list of technical information, economic information, including binding cost containment commitment information, about the project, and information about the experience, financial and technical capabilities of the sponsor. The CAISO has specified about 20 evaluation criteria and posts an evaluation document that discusses CAISO's evaluation of each proposal and the rationale for the project selected.

In addition to meeting the technical criteria for the project and demonstrating experience successfully developing transmission projects on budget and with good operating performance, CAISO's evaluation process has given significant weight to meaningful binding cost containment commitments. Meaningful cost containment commitments offered by some developers include construction cost caps (subject to escalation for changes in scope and other contingences), O&M cost caps for a few years, and/or future revenue requirements caps (amortization of the construction cost plus operating and maintenance expenses), subject to various contingencies. Other sponsors of proposals provide only cost estimates without firm cost containment commitments and rely on their experience and proposed construction and operating plans to convince evaluators of their merit. In this case, the default is FERC cost of service regulation with no performance incentives.

Table 1 provides information on all ten transmission projects that were put up for competitive solicitation by CAISO. Note the wide range of ISO cost estimates for some of these projects. Incumbents were awarded six projects and non-incumbents four projects.<sup>39</sup> The incumbents typically do not offer binding cost commitments in their proposals, relying on their

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<sup>39</sup> The Imperial Valley project winner might be reasonably classified as a non-incumbent, however.

**TABLE 1**  
**CALIFORNIA ISO COMPETITIVE TRANSMISSION PROJECTS<sup>1</sup>**

| <u>Project Name</u>                 | <u>Date Approved</u> | <u>ISO Planning Cost Estimate</u> | <u>Number of Bidders</u> | <u>Winning Bidder</u>  | <u>Cost Containment</u> |
|-------------------------------------|----------------------|-----------------------------------|--------------------------|------------------------|-------------------------|
| Imperial Valley Policy Element      | July 11, 2013        | \$25 million                      | 2                        | Incumbent <sup>2</sup> | Yes                     |
| Gates-Greg                          | November 6, 2013     | \$115-\$145 million               | 5                        | Incumbent              | No <sup>3</sup>         |
| Sycamore-Penasquitos                | March 4, 2014        | \$111-\$221 million               | 4                        | Incumbent              | No                      |
| Miguel 500KV                        | May 1, 2014          | \$30-\$40 million                 | 1                        | Incumbent              | No                      |
| Suncrest                            | January 6, 2015      | \$50-\$75 million                 | 2                        | Non-incumbent          | Yes                     |
| Estrella                            | March 11, 2015       | \$35-\$45 million                 | 4                        | Non-incumbent          | Yes                     |
| Wheeler Ridge Junction              | March 11, 2015       | \$90-\$140 million                | 4                        | Incumbent              | No                      |
| Spring                              | March 11, 2015       | \$35-\$45 million                 | 3                        | Incumbent              | No                      |
| Delaney-Colorado River <sup>4</sup> | July 10, 2015        | \$300 million                     | 5                        | Non-incumbent          | Yes                     |
| Henry-Allen To Eldorado             | January 11, 2016     | \$144 million                     | 3                        | Non-incumbent          | Yes                     |

<sup>1</sup> Developed from project solicitation evaluation reports. <http://www.aiso.com/planning/Pages/TransmissionPlanning/2013-2014TransmissionPlanningProcess.aspx>

<sup>2</sup> Project adjacent to selected proposer's territory but this territory is outside CAISO.

<sup>3</sup> Agreed only not to apply for FERC incentive rate of return on equity

<sup>4</sup> First "economic" or "market efficiency" project

track records and natural advantages they may have as incumbents. When an incumbent proposal without cost containment commitments is selected the costs of the project are recovered through standard FERC regulatory cost of service principles. The non-incumbents selected typically offer cost containment commitments --- construction cost caps subject to escalation for changes in scope and other contingencies, O&M cost caps, rate of return caps, etc. Once selected and completed these projects become regulated projects subject to cost of service regulation, constrained by any cost commitments that they have made.

Note that while the CAISO looks favorably on cost containment commitments, this alone will not lead to a favorable conclusion about the economics of the project favorably. In one project evaluation (Spring in Table 1), the ISO compared a proposal with a relatively high estimated cost but with a cost cap to a project having a much lower estimated cost without a cost cap but subject to FERC cost-of-service regulation procedures. The ISO chose the second proposal. The ISO also has developed its own planning cost estimates which serve as a kind of benchmark that bidders must beat. With one exception where there was only a single bidder, all of the projects received multiple proposals; between two and five proposals with 4 being the median number of competing proposals in each RFP.

#### b. MISO

The MISO has selected only two projects eligible for competitive solicitation since Order 1000. In both cases they are market efficiency projects (“reduce congestion costs”). In January 2016, the MISO issued its first RFP for a 345 KV transmission line between the Duff and Coleman substations, estimated to cost ~ \$60 million. Eleven proposals were received, of which several

were from non-incumbents.<sup>40</sup> Bids ranged \$24-\$55.7 million for construction costs, a range below the ISO's pre-bid estimate. The MISO issued a selection report in December 2016.<sup>41</sup> The sponsors all had previous transmission construction and operating experience. The evaluation report contains a short list of technical and economic evaluation criteria. The MISO evaluation process gives weights (points) to each of the evaluation criteria: Cost and Design – 30%; Project Implementation – 35%; operations and maintenance –30%; transmission planning participation — 5%. The proposals are evaluated against each criterion and then given an aggregate score. The MISO found all of the proposers to be highly qualified but noted significant differences in the attributes of the proposals, including wide differences in estimated costs. However, one proposal was a clear winner based on total points received. The MISO noted in particular that many of the proposals had innovative cost caps and cost containment provisions, including the sponsor awarded the project. The winner received the highest score for cost and design as well as the highest score overall. The winner was also a non-incumbent.<sup>42</sup>

The MISO issued an RFP for a second competitively bid proposal in July 2018 for a 500 kV line known as the Hartburg-Sabine project. The project had an estimated cost of \$129 million. As noted, this too is a market efficiency project (“reduce congestion costs” by 25% more than enough to pay for the project over time in expectation). The RFP received 12 responsive proposals, including proposals from non-incumbents. The bids ranged from \$95.4 million to \$133.9 million,

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<sup>40</sup> It is tricky to figure out whether a proposal is from an incumbent or a non-incumbent as the incumbents often use a subsidiary with a different name.

<sup>41</sup> <https://cdn.misoenergy.org/Duff-Coleman%20EHV%20345kv%20Selection%20Report82339.pdf>

<sup>42</sup> FERC 2017 considers the winner to be an incumbent. I would call it non-incumbent.. Republic Transmission LLC, a subsidiary of LS Power Associated, a private company very active in the independent transmission space, is the primary sponsor and appears to be a private company unaffiliated with a utility. Its partner is Big Rivers Cooperative which is a G&T coop that does not have a retail service territory, though Big Rivers may be owned by retail coops. In addition, press reports indicate that Hoosier, a rural electric coop, is supporting Republic in various ways and may take an interest in Republic Transmission, but it did not have an interest when the project was awarded. <https://www.elp.com/articles/2017/03/republic-transmission-wants-to-operate>. It's a matter of judgement.

with the ISO's ex ante estimate near the top of the range. An evaluation report was issued on November 27, 2018.<sup>43</sup> The evaluation criteria used for this second competitive MISO project are the same as for the first project. The evaluation criteria are clearly laid out, points are assigned to each project for the evaluation of its performance in each of the four evaluation "buckets." It is fairly clear from the discussion in the evaluation report that the MISO expects to see proposals that have cost caps and other cost containment commitments. The project was awarded to a non-incumbent with the highest total score (by far) as well as the highest score on cost/design and project implementation. The winning proposal capped several elements of the standard regulated annual revenue requirements as determined by FERC over the life of the project, subject to various contingencies.

It is interesting to note that market efficiency or economic projects must be justified primarily by the estimated savings in congestion costs over 15 or more years into the future. That is, the expected present discounted value of the congestion cost savings from the project must be greater (typically 25% greater) than the cost (present discounted value of revenue requirements) of the project. This is of course the situation that, in theory, would trigger a merchant investment under the classical merchant model. However, while these projects could be supported by expected congestion cost savings, the invisible hand did not lead to the development of the project. Rather they were selected through a regional planning process and the owner is compensated through FERC regulated cost recovery rule adjusted for the winning proposal's cost containment provisions. None of the proposals offered to be compensated based solely by the sale of congestion revenue rights.

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<sup>43</sup> <https://cdn.misoenergy.org/Hartburg-Sabine%20Junction%20500%20kV%20Selection%20Report296754.pdf>

c. SPP

The Southwest Power Pool (SPP) has held one competitive solicitation for the North Liberal to Walkemeyer 115Kv line with an estimated cost of \$16.8 million. The substations at either end of the line also would need upgrading, but the substation components of the projects were reserved for the incumbents.<sup>44</sup> The project's origin was SPP's 2015 10-Year integrated transmission plan prepared in 2014. An RFP was issued on May 5, 2015.<sup>45</sup> The SPP Board appointed an outside expert panel to review the proposals.<sup>46</sup> The evaluation process allocated points in five scoring categories. The scoring categories were engineering, project management, operations, rates (costs, including cost containment commitments), and financing. Incentive points could also be earned. The results of the RFP and the evaluation process were announced on April 1, 2016. Eleven (11) proposals were submitted. However, the engineering design review determined that five of the proposals did not meet minimum engineering standards. The proposals exhibited a wide range of cost estimates --- from \$9.5 million to \$30 million --- 40 year NPV of revenue requirements. The process yielded a recommended proposal and an alternate proposal based on total points earned in the five evaluation categories. Both proposals has estimated construction costs of about 50% of the ISO's pre-bid estimate. The recommended proposal had the second lowest estimated cost and the alternate the third lowest. Cost containment commitments in the form of cost caps of some type were considered in the rate analysis but the estimated costs of the proposals that made such commitments were much higher than the proposals that were selected as first and alternate. The details of the cost containment commitments were unfortunately

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<sup>44</sup> The CAISO competitive bid project that yielded one bidder was also a substation project owned by the sole bidder. Upgrades to substations owned and operated by an incumbent and that will continue to be owned and operated by the incumbent are probably not a good opportunity for competitive bidding.

<sup>45</sup> [https://www.spp.org/documents/28843/spp-rfp-000001\\_website%20watermarked%20posting%20version\\_regdateupdate080315.pdf](https://www.spp.org/documents/28843/spp-rfp-000001_website%20watermarked%20posting%20version_regdateupdate080315.pdf)

<sup>46</sup> [https://www.spp.org/documents/37708/iep%20recommendation%20report%20with%20process%20and%20appendix%20public%20redacted%20041216\\_redacted.pdf](https://www.spp.org/documents/37708/iep%20recommendation%20report%20with%20process%20and%20appendix%20public%20redacted%20041216_redacted.pdf).

redacted from the public report and the evaluation report did not identify the names of the companies submitting the proposals, though the winner was an incumbent. The project was ultimately cancelled by SPP in July 2016 when an update to the long-term transmission plan found that the project was no longer needed.<sup>47</sup> It does not appear that SPP has issued this type of RFP since then. Note that 86 other transmission projects were approved by the SPP board at the same time as the winner of the one competitive procurement that SPP has initiated was announced,<sup>48</sup>

d. NYISO

The NYISO manages and integrates a local transmission owner planning process, a regional reliability transmission planning process, an economic transmission planning process (“market efficiency” projects), and a public policy transmission planning process.<sup>49</sup> NYISO is a single state ISO and the New York Public Service Commission (NYPSC), the electric utility regulator in New York, is heavily involved in the process. The NYPSC must approve the need for transmission projects recommended by the NYISO, the RFP used by the NYISO, the evaluation criteria, and appears to be at least informally involved in the selection made by the NYISO after it runs the RFP and recommends a winner. Effectively the NYISO and the NYPSC work cooperatively in tandem to define needs, the RFP process and selection criteria and the ultimate selection.

While CAISO, MISO and SPP propose specific projects for competitive procurement --- e.g. a line from point A to point B with a certain voltage and transfer capacity, etc., the NYISO

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<sup>47</sup> [https://www.spp.org/documents/28843/spp-rfp-000001\\_website%20watermarked%20posting%20version\\_regdateupdate080315.pdf](https://www.spp.org/documents/28843/spp-rfp-000001_website%20watermarked%20posting%20version_regdateupdate080315.pdf) .

<sup>48</sup> <https://www.spp.org/newsroom/press-releases/spp-board-votes-to-lower-planning-reserve-margins-award-first-competitively-bid-project-approve-363m-in-transmission-upgrades/>

<sup>49</sup> <https://www.nyiso.com/csppf>

has adopted a “sponsorship” model for projects that are put out for competitive procurement. Under this model, the ISO specifies a transmission “need” and invites proposals for projects to satisfy this need. The NYISO has only issued RFPs for two “public policy” transmission needs since Order 1000 became effective. All of the other transmission projects selected for development come out of the NYISO’s regional planning process which relies heavily on local transmission plans submitted by the incumbent transmission owners. Qualified transmission developers can and do participate in this planning process and may, in theory anyway, put forward their own projects to be selected for development.

The NYISO initiated the first public policy competitive procurement in August 2014.<sup>50</sup> The public policy “need” is referred to as the “Western New York Public Policy Transmission Need.” The NYISO identified the overloaded transmission lines in Western New York in a baseline case (later updated) as needing additional transfer capacity. On November 1, 2015 the NYISO issued an RFP soliciting proposals for the identified public policy need. The NYISO received 12 project proposals by December 31, 2015 submitted by seven unique bidders (3 bidders submitted two or more proposals).<sup>51</sup> Several different configurations were proposed to meet the specified need to increase transfer capacity in this part of the New York transmission network. The estimated construction costs of these proposal varied from \$157 million to \$487 million, though the NYISO takes many other factors into account in addition to construction costs. The winning bidder had an estimated construction cost of \$181 million. In May 2016 the NYISO issued a “technical

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<sup>50</sup>The public policy transmission need was identified as improved access to hydroelectric energy from the Niagara project in Western New York State and increased imports of renewable energy from Ontario, involving a 3,700 Mw increase in transfer capacity. This is a big project with multiple transmission facilities.[https://www.nyiso.com/public/webdocs/markets\\_operations/committees/bic\\_espwg/meeting\\_materials/2016-06-07/PPTPP\\_Update.pdf](https://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2016-06-07/PPTPP_Update.pdf).  
[http://www.nyiso.com/public/webdocs/markets\\_operations/services/planning/Planning\\_Studies/Public\\_Policy\\_Documents/Western\\_NY/NYISO\\_WesternNY\\_PPTN\\_VSA\\_2016-05-31.pdf](http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Public_Policy_Documents/Western_NY/NYISO_WesternNY_PPTN_VSA_2016-05-31.pdf).

<sup>51</sup> The sponsorship model as implemented by the NYISO and PJM allow developers to submit multiple project proposals to satisfy an identified need.



sufficiency” report designating ten of these proposals as meeting the need from a technical perspective. This report was then sent back to the NYPSC to determine whether it continued to believe that this public policy need still existed and, if so, to provide guidance to allow the NYISO to proceed with a more complete evaluation of these projects.<sup>52</sup> On October 13, 2016 the NYPSC confirmed the need for the Western New York Transmission expansion and sent it back to the NYISO for a more complete analysis. The NYISO then proceeded to evaluate the competing projects based on a set of quantitative and qualitative metrics. These included the technical attributes of the proposed project, whether it satisfied the identified need, total project cost, cost per MW, expandability, access to rights of way, routing, production cost savings, congestion costs savings, cost of carbon impacts, and other considerations. The review involved a lot of technical detail.

The NYISO staff recommended a winning proposal and the recommendation was approved by the NYISO Board in October 2017.<sup>53</sup> The proposal selected had one of the lowest cost estimates and the shortest construction schedules of those proposals submitted (\$181 million). It is sponsored by a non-incumbent. While some of the proposals had cost containment commitments, the NYISO did not take them into account, noting that Order 1000 did not require that it do so. It did suggest that it would do so in future RFPs if FERC approved necessary changes to the ISO’s OATT. The NYISO also indicated that it would proceed with a “lessons learned” process to improve future competitive procurements. The project is expected to go into service in June 2022.

The second competitive procurement process for public policy transmission needs grew out of the public policy needs transmission process initiated in August 2014. In an order dated

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<sup>52</sup> FERC has now accepted a change in the ISO’s tariff that eliminates this NYPSC sign-off step. *Megawatt Daily* and Platt’s Market Center, February 11, 2019.

<sup>53</sup> New York ISO, Western New York Public Policy Planning Report, October 17, 2017.

December 17, 2015 the NYPSC designated a group of transmission needs in the Central East and Southeast portions of the New York State transmission network as public policy transmission needs collectively referred to as the “AC Public Policy Transmission Needs.” This NYPSC order is interesting because it addresses the issue of cost containment incentives directly:<sup>54</sup>

“In the absence of a cost-containment incentive mechanism, FERC practice is to generally allow full recovery through the NYISO Open Access Transmission Tariff of any prudently incurred costs that exceed the developer's original estimate. The Commission already ruled in these proceedings on what incentive would be appropriate to ensure accurate cost estimates.

If actual costs come in above a bid, the developer should bear 20% of the cost over-runs, while ratepayers should bear 80% of those costs. If actual costs come in below a bid, then the developer should retain 20% of the savings. Furthermore, if the developer seeks incentives from FERC above the base return-on-equity otherwise approved by FERC, then the developer should not receive any incentives above the base return-on-equity on any cost overruns over the bid price. The bid price would therefore cap the costs that may be proposed to FERC for incentives.

The Commission cannot predict at this time whether FERC will accept the Commission's preference for a cost-containment incentive mechanism. The Commission also is not privy to the bidding strategies of the potential developers. Those facts raise a concern that it may be very difficult to fairly compare bids if the bids are based on different models of risk. For example, if two competing projects appear to offer equivalent value, but one offers a lower bid subject to the recovery of all actual costs, and the other offers a higher bid, but the costs are firm, it may be difficult to choose a winner.

The Commission is dedicated to a process that will ensure equity and a fair comparison. Bids should be sought from all developers in the alternative assuming both the FERC ordinary full recovery regime and the Commission's cost-overrun-sharing incentive regime. The Commission believes that this additional information as to risk assumption will be of assistance and may be crucial to discerning between close bids.”<sup>55</sup>

In February 2016, the NYISO issued a request for proposals that included technical information and baseline analysis to meet these needs. This RFP has much more specific transmission need/project specifications, divided into two segments, than did the Western need RFP. Fifteen proposals were submitted in response to the RFP from five unique sponsors. Seven

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<sup>54</sup> State of New York Public Service Commission, Case 12-T-0502, Case 13-E-0488, and related cases, December 17, 2015.

<sup>55</sup> *Ibid.*, pages 48-49.

proposals were for segment A, six for segment B, and two for both segments (the segments appear to be quite independent geographically but perhaps not electrically) required to meet the specified public policy needs. An additional proposal for a distributed generation option was also submitted but failed to qualify on technical sufficiency grounds. The estimated construction costs (without contingencies) for segment A varied from \$375 million to \$659 million and for segment B from \$275 million to \$380 million. In October 2017, the NYISO issued its technical sufficiency assessment report for the proposals submitted in response to the RFP. Thirteen of the proposals met the NYISO's technical sufficiency criteria.<sup>56</sup> The NYISO's assessment then went to the NYPSC for confirmation that the AC public policy transmission need continued to exist, as it confirmed in an order dated January 4, 2017.<sup>57</sup> In March 2018, the NYISO issued a technical review report. A proposal ranking analysis was issued by the NYISO staff in June 2018. The same development consortium, a non-incumbent and the New York Power Authority, which I suppose can be considered to be an incumbent though it is not FERC or NYPSC regulated, was initially selected to build and operate both segment A and Segment B specified in the RFP. The Board of the NYISO requested additional analyses to address a number of issues. The NYISO issued a report "addendum" in response on December 27, 2018.<sup>58</sup> This led to a change in the proposal selected for segment B of the project, and this segment of the project will now be built by a consortium led by an incumbent. The Board of the NYISO subsequently approved the proposal selected initially for segment A and the revised selection for segment B.<sup>59</sup> The estimated

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<sup>56</sup> NYISO, "AC Public Policy Transmission Need: Viability and Sufficiency Assessment," October 27, 2016.

<sup>57</sup> State of New York Public Service Commission, Case 12-T-0502, Case 13-E-0488, and related cases, January 24, 2017. I understand that the NYISO has filed tariff revisions with FERC which, among other things, eliminate this intermediate step because it takes too much time. *Megawatt Daily*, December 12, 2018.

<sup>58</sup> <https://www.nyiso.com/documents/20142/1390750/AC-Transmission-PPTN-Draft-Report-Addendum.pdf/898f1cb0-3f98-a26b-3866-0118dedafaae>

<sup>59</sup> <https://www.nyiso.com/documents/20142/1390750/Board-Memo-on-AC-Transmission-FINAL-c.pdf/8eba9661-6ab3-0311-de12-5d54d255f11e>

construction cost for the winning bidder for segment A was \$556 million and for segment B \$341 million. The winners did not bid the lowest construction costs, but other economic impacts (e.g. congestion costs, capacity deferral values), technical, and social (e.g. effects on CO2 emissions) gave them the highest rankings.

The NYISO has subsequently issued two requests for suggestions for additional public policy transmission needs but these requests have not yet led to the commencement of an RFP process.<sup>60</sup>

e. PJM

PJM is by far the largest RTO/ISO in the country. Its origin can be traced back to a multi-state power pool created in 1927. PJM now covers generating and transmission facilities in 13 states plus the District of Columbia with about 180,000 Mw of generating capacity and 85,000 miles of transmission lines. About \$30 billion of investment in transmission capacity has been selected in PJM's Regional Transmission Expansion Planning process (RTEP) since 2000.<sup>61</sup> PJM manages a set of wholesale markets for energy, ancillary services, and capacity in the PJM region, relying on for the energy and ancillary services markets security-constrained bid-based market models with nodal prices.

PJM had a comprehensive regional transmission planning process and associated procedures prior to Order 1000 the Regional Transmission Expansion Plan or RTEP. Process

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<sup>60</sup> [https://www.nyiso.com/documents/20142/1406936/Public\\_Policy\\_Needs\\_Solicitation\\_2016-08-01.pdf/c110897d-e37b-1611-d935-826124b41ab4](https://www.nyiso.com/documents/20142/1406936/Public_Policy_Needs_Solicitation_2016-08-01.pdf/c110897d-e37b-1611-d935-826124b41ab4) ; <https://www.nyiso.com/documents/20142/1406936/2018-19-PPTPP-Needs-Solicitation-Letter.pdf/83907505-4012-3813-f3b3-f0eda17fa0dd> .

<sup>61</sup> This excludes the costs of Supplemental projects and Network projects. 2017 PJM RTEP Book 1 page 4; <https://www.pjm.com/planning.aspx>. Accessed January 12, 2019. "Project Statistics," January 10, 2019. <https://www.pjm.com/-/media/committees-groups/committees/teac/20190110/20190110-project-statistics-2018.ashx>

changes to comply with Order 1000 took effect on January 1, 2014, though these are properly viewed as enhancements to existing processes. PJM began to implement a competitive planning process consistent with Order 1000 in 2013 when it opened two competitive “windows.”<sup>62</sup> The PJM staff works with the stakeholder Transmission Expansion Advisory Committee (TEAC) and ultimately the independent PJM Board to approve changes to the regional plan, new projects falling into certain categories, and project cancellations. PJM publishes extensive information about these processes on its web site.

As noted earlier, PJM has adopted what it calls a “sponsorship” model. Rather than specifying a particular project (e.g. build a 220Kv line from A to B to increase transfer capacity by X Mw), PJM publishes a set of reliability violations (reliability projects) or a set of highly congested interfaces (market efficiency projects) and solicits proposals from incumbent and non-incumbent transmission developers to resolve the violations or to reduce forecast congestion cost sufficient to justify the investment. Market efficiency projects must have a benefit/cost ratio great than 1.25. In order to solicit projects PJM opens various competitive “windows.” Projects that are five years out or more are solicited in a “long-term window.” Projects that are three to five years out are solicited in a “short-term” window. Projects that are less than three years out are classified as “immediate need” projects. If there is insufficient time to open a 30-day window and evaluate proposals for immediate need projects, PJM identifies a solution and designates an incumbent to implement the solution. There are other exclusions from PJM’s RTEP competitive planning projects. These include “Supplemental Projects,” which are projects designated by transmission owners to meet local planning criteria and to replace aging infrastructure, and “Network Projects” which are projects associated with the interconnection of generators to meet

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<sup>62</sup> 2013 PJM Regional Expansion Plan, Book 1 page 13 and page 14, 2016. <https://www.pjm.com/library/reports-notices/rtep-documents/2013-rtep.aspx>

power delivery requirements. They are reviewed by sub-regional committees established by PJM and the TEAC but do not go through the same level of PJM review as projects designated to meet NERC and regional reliability criteria and market efficiency projects.<sup>63</sup> Nor are they included in PJM's competitive procurement windows.<sup>64</sup> These exclusions from the competitive RTEP process are not trivial. Between 2013 and 2018 the estimated cost of new baseline RTEP projects was about \$12 billion and the estimated costs of new Supplemental projects was about \$19 billion.<sup>65</sup> Over a longer period of time, including the period before the first competitive window in 2013, about \$29 billion has been or is estimated to be spent on RTEP Baseline projects and \$26 billion on Supplemental projects. Another \$7 billion was spent on Network projects.<sup>66</sup> FERC has recently approved additional exclusions from the RTEP competitive window process for projects under 200 kV and for transmission substation equipment.<sup>67</sup> Nevertheless, many more transmission projects (both for reliability violations and market efficiency opportunities) have been mediated through PJM's formal competitive transmission planning process than is the case for the other ISOs. PJM has also implemented an interregional planning process and identified potential interregional projects with MISO to reduce congestion between the two ISOs.<sup>68</sup>

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<sup>63</sup> In 2016 FERC initiated an investigation of the "openness" of these regional planning processes. It found that they were not sufficiently open and violated the open planning rules established by Order 870 (enhanced by Order 1000). PJM subsequently made a compliance filing and it was accepted by FERC. 116 FERC ¶ 61,217, September 26, 2018. It is pretty clear from the record in this proceeding that FERC is much more interested in ensuring that planning processes are "open" to all stakeholders, including potential non-incumbent transmission developers, than it is in more structured competitive procurement processes.

<sup>64</sup> FERC issued an Order on February 15, 2018 which found that the local transmission owners and subregional planning processes associated with Supplemental projects violated the transparency and openness requirements in Order 890. 162 FERC ¶ 61,129 February 15, 2018. FERC accepted PJM and transmission owner compliance filings on September 16, 2018. 164 FERC ¶ 61,217 September 26, 2018.

<sup>65</sup> "Project Statistics, PJM Transmission Expansion Advisory Committee, page 6, January 10, 2019.

<https://www.pjm.com/-/media/committees-groups/committees/teac/20190110/20190110-project-statistics-2018.ashx>

<sup>66</sup> Ibid. page 10.

<sup>67</sup> 2017 PJM RTEP Book 1 page 9.

<sup>68</sup> 2017 PJM Regional Transmission Expansion Plan Book 3 page 240.

**TABLE 2  
PJM RTEP Windows 2013-2018**

|  | Window Objective   | Proposals | Proposal From Incumbents | Proposal From Non-Incumbent | Entities | Proposals approved by PJM Board | Approved Greenfield Projects | Approved Upgrade Projects | Approved Incumbent | Approved Non-Incumbent |
|--|--|-----------|--------------------------|-----------------------------|----------|---------------------------------|------------------------------|---------------------------|--------------------|------------------------|
| <b>2018 RTEP Proposal Window 1</b>               | 2023 Summer, Winter and Light Load: N-1, Gen Deliv, Load Deliv N-1-1   | 7         | 7                        | 0                           | 2        | N/A                             | N/A                          | N/A                       | N/A                | N/A                    |
| <b>2017 RTEP Proposal Window 1</b>               | 2022 Summer, Winter and Light Load: N-1, Gen Deliv, Load Deliv N-1-1   | 51        | 36                       | 15                          | 10       | 10                              | 0                            | 10                        | 10                 | 0                      |
| <b>2016/17 RTEP Long Term Proposal Window 1A</b> | Market Efficiency  | 3         | 2                        | 1                           | 2        | 1                               | 0                            | 1                         | 1                  | 0                      |
| <b>2016/17 RTEP Long Term Proposal Window</b>    | Market Efficiency Congestion, 15 Year Reliability Analysis   | 96        | 51                       | 45                          | 19       | 4                               | 0                            | 4                         | 4                  | 0                      |
| <b>2016 RTEP Proposal Window 3 Addendum 1</b>    | Winter Reliability   | 6         | 3                        | 3                           | 3        | 3                               | 0                            | 3                         | 3                  | 0                      |
| <b>2016 RTEP Proposal Window 3</b>               | Winter Reliability, Light Load Reliability, Short Circuit  | 30        | 15                       | 15                          | 7        | 6                               | 0                            | 6                         | 6                  | 0                      |
| <b>2016 RTEP Proposal Window 2</b>               | N-1 Thermal and Voltage; Gen Deliv and Common Mode Outage, Load Deliv Thermal and Voltage; N-1-1 Thermal and Voltage   | 87        | 53                       | 34                          | 13       | 14                              | 0                            | 14                        | 14                 | 0                      |
| <b>2016 RTEP Proposal Window 1</b>               | Deliverability and Common Mode Outage Violations related to Carson-Rogers Rd 500 kV and Chesterfield-Messer Rd-Charles City Rd 230 kV and Dominion Local TO Criterion for End of Life Facilities | 25        | 7                        | 18                          | 7        | 2                               | 0                            | 2                         | 2                  | 0                      |
| <b>2015 RTEP Proposal Window 2</b>               | TO Thermal Criteria, TO Voltage Criteria; Light Load Thermal and Voltage   | 23        | 14                       | 9                           | 4        | 6                               | 1                            | 5                         | 6                  | 0                      |
| <b>2015 RTEP Proposal Window 1</b>               | N-1 Thermal and Voltage; Gen Deliv and Common Mode Outage, Load Deliv Thermal and Voltage; N-1-1 Thermal and Voltage   | 91        | 34                       | 57                          | 9        | 20                              | 1                            | 19                        | 20                 | 0                      |
| <b>2014/15 RTEP Long Term Proposal Window</b>    | Long Term Reliability Criteria; Long Term TO Criteria; Market Efficiency   | 119       | 67                       | 52                          | 22       | 14                              | 1                            | 13                        | 13                 | 1                      |
| <b>2014 RTEP Proposal Window 2 Addendum 2</b>    | N-1-1 Voltage Drop   | 10        | 2                        | 8                           | 4        | 1                               | 0                            | 1                         | 1                  | 0                      |
| <b>2014 RTEP Proposal Window 2 Addendum 1</b>    | N-1-1 Voltage Drop   | 4         | 1                        | 3                           | 3        | 0                               | 0                            | 0                         | 0                  | 0                      |

|                                    |   |            |            |            |            |            |          |            |            |          |
|------------------------------------|---|------------|------------|------------|------------|------------|----------|------------|------------|----------|
| <b>2014 RTEP Proposal Window 2</b> | Reliability Criteria Thermal and Voltage; TO Criteria | 79         | 58         | 21         | 14         | 35         | 4        | 31         | 34         | 1        |
| <b>2014 RTEP Proposal Window 1</b> | Reliability Criteria - Thermal                        | 109        | 62         | 47         | 15         | 22         | 0        | 22         | 22         | 0        |
| <b>Market Efficiency</b>           | Market Efficiency                                     | 38         | 11         | 27         | 6          | 1          | 0        | 1          | 1          | 0        |
| <b>Artificial Island</b>           | Operational Performance                               | 26         | 14         | 12         | 7          | 3          | 1        | 2          | 2          | 1        |
| <b>2013-2017</b>                   |   | <b>804</b> | <b>437</b> | <b>367</b> | <b>147</b> | <b>142</b> | <b>8</b> | <b>134</b> | <b>139</b> | <b>3</b> |

2018 not completed as of 2/16/19

Sources: See Data Appendix



Table 2 contains summary information about the proposals to develop projects submitted and selected in all of the RTEP and efficiency windows opened between 2013 and 2017. (Selections have not yet been made for the 2018 window at the top of the table.) There were 16 windows opened and completed during the 2013-2017 time period.<sup>69</sup> The typical windows is opened with a fairly large set of reliability (“flowgate”) violations on the PJM network or a fairly small set of potential market efficiency projects. Note that each reliability window “targets” related types of flowgate violations as indicated in the first column of Table 2. Depending on whether it is a short term or long-term window, pre-qualified developers have either 60 or 120 days to submit proposals.<sup>70</sup> Once the window is closed the PJM staff evaluates the proposals and makes recommendations to the Transmission Expansion Advisory Committee (TEAC). The TEAC determines whether to accept these recommendations and then forwards the proposals selected to the PJM Board for final approval.

Table 2 indicates that there are 803 proposals made in response to 16 RTEP competitive windows during the 2013-17 period and 142 projects were awarded to developers based on these proposals. Opening competitive windows has certainly created a lot of interest by developers. It is evident that transmission developers (“entities”) submit an average of about five proposals in a typical window, but multiple proposals may respond to different flowgate violations or market efficiency opportunities. About 45% of the proposals came from non-incumbents. However, only 3 of these projects were awarded to non-incumbents.<sup>71</sup> About 95% of the awards were for upgrades

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<sup>69</sup> Two additional windows were opened in 2018. As this is written one window closed in 2018 and the other closes in 2019. No information about the proposals selected had been posted as of January 12, 2019.

<sup>70</sup> A 30-day window may be opened for immediate need projects.

<sup>71</sup> The three projects are: (1) one portion of the segments awarded in the Artificial Island Solicitation awarded to a subsidiary of LS Power, (2) a market efficiency project referred to as AP-South awarded to Transource, a subsidiary of American Electric Power (AEP), in connection with the 2014/2015 RTEP, and (c) the Thorofare project in West Virginia also awarded to Transource in connection to the 2014 RTEP Window 2. It is not clear to me that the Thorofare project meets the PJM staff’s criteria for non-incumbent as the project seems to run through the territory of an AEP subsidiary and the history of the project indicates AEP involvement with the development of the project.

to existing facilities, which under PJM rules are designated to the incumbent utility. This may help to explain why so few non-incumbents were selected. There were only seven greenfield projects awarded so non-incumbents were awarded three of the seven greenfield projects.

With a few exceptions, the details of the evaluations performed by the PJM staff and how the evaluations led to the project awards is not particularly transparent. The nature of PJM's sponsorship model makes head to head comparisons between proposals quite difficult since they are not "bidding" to develop a specific project but rather submit proposals for different sets of solutions to one or more flowgate violations or designated mitigation of congestion costs opportunities. While a typical PJM staff report to the TEAC for reliability projects describes in some detail the recommended solution to the flowgate violation, it does not discuss whether other equivalent proposals to solve the same violations were submitted or why they were rejected. The evaluation of market efficiency proposals is more transparent.

PJM opened the first RTEP window on August 29, 2013. In this window, PJM solicited proposals to improve operational performance of the transmission system in the Artificial Island area of Southern New Jersey. Artificial Island is the location of three nuclear generating plants owned by PSE&G. The publicly available evaluation of the proposals in response to the Artificial Island Window is more transparent than is typically the case for PJM. PJM received 26 proposals with initial cost estimates ranging from \$100 million to \$1.55 billion. The proposals put forward represent a technologically diverse set of partial and complete solutions to the reliability issues identified by PJM in the RFP.<sup>72</sup> The projects are not directly comparable because they include both

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The Transource AP-South project was last re-evaluated by the TEAC in September 2018 and continued to show a benefit/cost ratio greater than 1.25. <https://www.pjm.com/-/media/committees-groups/committees/teac/20180913/20180913-ap-south-9a-project-reevaluation-sept-2018.ashx>

<sup>72</sup> Artificial Island Project Recommendation White Paper, PJM, July 29, 2015. <https://www.pjm.com/-/media/committees-groups/committees/teac/postings/artificial-island-project-recommendation.ashx?la=en>.

partial and complete solutions to the Artificial Island reliability issues, though correcting for differences it appears that the incumbent made by far the most-costly proposals and did not offer to agree to cost-containment commitments.<sup>73</sup>

This window was opened a few months before PJM's Order 1000 compliance date and PJM characterized this solicitation as a trial run.<sup>74</sup> Competing projects are specified, compared to one another and the rationale for the proposals selected are specified fairly clearly. However, this solicitation is different from the subsequent reliability windows opened by PJM as it focused on a single set of reliability challenges in one area of the bulk transmission network around Artificial Island. In this sense, the application of the sponsorship model in this case is more like the two solicitations conducted by the New York ISO which also claims to have a sponsorship model. The Artificial Island White Paper discusses the evaluation process in some detail.<sup>75</sup> The awards went to three projects that together comprise a complete solution to the Artificial Island reliability issues, one to be developed by a non-incumbent, one to be developed by the incumbent (static var compensator, substation expansion, new transformer), and one involving the installation of high-speed optical grounding wire communications on existing transmission lines owned by multiple incumbents.

The complete project configuration selected had an initial cost estimate of about \$275 million.<sup>76</sup> The non-incumbent awardee's proposal for its segment of the project made capital cost commitments in the form of a cost cap subject to various contingencies. The contingencies included, changes in scope, financing, inflation, and other factors. Capital cost commitments were

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<sup>73</sup> Ibid. pages 12-13.

<sup>74</sup> Ibid. page 1.

<sup>75</sup> <https://www.pjm.com/-/media/committees-groups/committees/teac/postings/artificial-island-project-recommendation.ashx?la=en>

<sup>76</sup> Ibid. pages 39-40.

a new idea for PJM and such commitments had not been, and are not now, required. Since cost commitments were a new idea to PJM (and I suspect for FERC), PJM gave the other four finalists a chance to resubmit bids with cost commitments. Three of the four submitted bids with a variety of capital cost commitment structures.<sup>77</sup> PJM staff adjusted the proposals to include estimates of the costs of segments not included in each proposal to make them more or less technically equivalent.

The adjusted cost estimates of the four finalists ranged from \$263 million to \$380 million in then current dollars.<sup>78</sup> The adjusted cost estimates for two of the proposals were very close, but PJM found that the proposal submitted by the non-incumbent had fewer contingencies and exclusions and the lowest expected cost (but similar to the next lowest cost estimate) It was awarded the 230kV portion of the project from Delaware to Artificial Island (about 50% of the estimated cost of the entire project). The incumbent was awarded the portion of the project for a static var compensation, substation upgrades and a new transformer.

The saga surrounding this project did not stop there. In 2016 PJM suspended the project for further reconsideration and then reinstated the project in 2017. The Delaware Public Service Commission granted a certificate of public need and necessity for the Delaware portion of the project in December 2018 subject to FERC approval of cost allocations to Delaware for the project meeting conditions specified by the Commission. As this is written, the ball is now in FERC's court, where cost allocation and the implementation of cost commitments are likely to be issues. Note that the solicitation, evaluation, and regulatory process started in 2013 and had not been completed by the end of 2018.

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<sup>77</sup> Ibid. pages 32-35.

<sup>78</sup> Ibid. page 33.

I found no indication that the two projects awarded to non-incumbents in two other windows contained cost-containment commitments.<sup>79</sup>

## VI. Discussion

It is difficult to draw strong conclusions about the performance attributes of the experience to date in the U.S. with competitive procurement for transmission projects. Putting PJM aside for the moment, there are only 15 projects in the U.S. that have been selected by the ISOs through a formal open competitive procurement process since 2014. We can add PJM's first competitive window for the Artificial Island window to this total to get to 16. Many of these projects have not yet been completed, complete realized construction cost data are not readily available for those projects that have been completed, and there is no record of how the cost commitments and the associated contingency provisions contained in the winning proposals, have been applied. Turning to PJM, in principle, all of the potential projects to respond to reliability violations and potential net reductions in expected congestion costs are open for competitive bidding. Clearly, participation in the PJM competitive windows has been quite robust. There were five times more proposals submitted than projects selected through the RTEP between 2013 and 2017. Many proposals have been submitted by non-incumbents. However, 95% of the projects selected have been upgrades to existing facilities and designated to the incumbent. Supplemental projects selected through sub-regional planning processes are not approved by the PJM board. In February 2018, FERC also found that the sub-regional planning processes had not met Order 890's open planning requirements and ordered that changes be implemented.<sup>80</sup> Given the small number of

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<sup>79</sup> I would also classify one of these projects as an incumbent rather than a non-incumbent project but I have accepted PJM's categorization for counting purposes here.

<sup>80</sup> 162 FERC ¶ 61,129, February 15, 2018

projects that actually turn out to represent competitive opportunities for non-incumbents and for competitive offers to adopt various cost containment provisions, there may be opportunities to simplify the current process to save unnecessary time and effort. I will return to this question below.

Yet, there is quite a bit to learn from the 16 projects selected through an organized competitive procurement process by ISOs since Order 1000 went into effect. As noted earlier, one of the challenges for regulators is uncertainty about what the cost of an efficiently designed and built project should be. This is an especially important question for the U.S., because FERC presently does little regulation of the reasonableness of the costs presented for inclusion in transmission operators' revenue requirement and does not apply performance-based mechanisms as have been used in other countries and other industries. It is clear from the data on ISO cost estimates and the range of cost estimates and cost commitments contained in competing proposals that there is a wide range of potential cost realizations. Indeed, perhaps the most striking thing about the proposals submitted in response to these RFPs is the wide range of estimated costs observed between the various proposals for essentially the same project or to meet the same transmission expansion need. Cost containment mechanisms aside, the wide range of cost estimates convinces me that there is substantial potential benefit in competitive procurement per se beyond non-incumbent participation in open regional planning processes unburdened by incumbent rights of first refusal. ISO evaluators and regulators can now see variations in cost estimates that they never saw when the projects were proposed and developed by a single incumbent utility. When non-incumbents have been selected their projects often have significantly lower cost estimates than the incumbent's, often combined with cost containment commitments. Competitive procurement may also induce incumbents and non-incumbents to sharpen their

pencils, Artificial Island being a good example. This kind of competitive information is also necessary for an ISO to choose the most efficient or cost-effective projects as required by Order 1000. This information can also provide benchmarks for FERC if it decides to get more engaged in regulating transmission costs. While the jury is necessarily still out on whether competitive procurement leads to lower costs to meet specific transmission needs, I think that there are good reasons to believe that it likely does. The evidence from other countries, especially Argentina, is consistent with this view.

It is sometimes argued that formal competitive procurement that allows incumbents and non-incumbents to compete is not necessary because incumbent transmission owners seek competitive bids for equipment and contracts and primarily provide management oversight. This is not a compelling argument. The competitive procurements demonstrate that competing transmission developers can reduce expected costs by coming up with innovative designs to resolve transmission needs identified through the ISO regional planning process, taking on more performance risk, foregoing certain FERC revenue requirements “incentives” for which they would otherwise be eligible, etc. The cost containment commitments and related incentives (and contingencies) can be a substitute for more direct performance-based regulation of costs and could even help FERC to design and apply incentive regulation mechanisms more broadly to transmission costs. It is important to better understand how these cost containment mechanisms work in practice over time and interact with FERC’s cost of service/revenue requirement recovery policies.

The costs and construction times for any developer of transmission projects, especially greenfield projects, can be very uncertain and, as a result, are not well adapted to high powered incentive schemes (e.g., a firm construction cost commitment) that do not leave a lot of expected

rent on the table for the developer. Those proposals that do offer cost containment commitments also include many contingencies that would relax these cost commitments. Will the contingencies overwhelm the commitments? Time and data availability will be necessary to answer this question. On the other hand, incumbent projects regulated under traditional regulatory arrangements also can and do incur significant cost overruns. Over the period 2014-2017, the PJM RTEP reported over \$1.3 billion of escalation in *estimated* construction costs.<sup>81</sup> The CREZ program in Texas experienced an 40% increase in realized costs from the initial estimates. Only some of the gap can be explained by input cost inflation. Pfeifenberger et.al. (2018) offer additional evidence on both cost overruns and the range of costs observed in the competitive procurements that have taken place.

While the competitive procurement process may weed out projects that are not technically feasible and/or have higher projected costs than equivalent alternatives, in the end when a project is completed it becomes a FERC cost of service regulated project, subject to any cost containment commitments and contingencies agreed to with the ISO. These costs ultimately end up in the charges paid by transmission customers, primarily distribution utilities, and in this case passed along to retail customers in wires charges.

It would be desirable for ISOs to place more weight on cost control and performance incentives in their evaluations of proposals to lead FERC in this direction. However, it is quite clear that the ISOs do not want to become, and are not supposed to be, economic regulators in this sense and this is not where their experience lies. Order 1000 gives the ISOs the responsibility to select the least cost or most cost-efficient projects but the ISOs do not have the regulatory authority to monitor and enforce cost commitments or to evaluate whether transmission costs incurred are

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<sup>81</sup> PJM annual RTEP reports, various years; <https://www.pjm.com/library/reports-notices/rtep-documents.aspx>



“just and reasonable.” These regulatory responsibilities are ultimately FERC’s responsibilities and, as discussed further below, FERC should take a more active role in facilitating the consideration of voluntary cost containment and performance incentives offered by developers in the project selection process. The implementation of cost containment provisions through the FERC revenue requirements process needs to be clarified as well.

It is also clear that participation in the competitive procurement process and the evaluation of competing proposals is complex, expensive, and time consuming. Transmission developers must submit a great deal of technical, financial, past development experience, detailed development and right acquisition plans and other information to respond effectively to an RFP. The evaluation process is also quite complex, taking a wide variety of factors into consideration in evaluating competing projects. The process of developing and issuing a good RFP, proposal creation by developers, and ISO evaluation is a time-consuming process. However, some ISOs appear to be able to complete a full cycle in less than a year. Others can take five or more years. It would be helpful if the ISOs could share best practices and adopt them to streamline the process.

Participating in regional transmission planning processes and competitive transmission procurement processes is not for small inexperienced organizations. These activities require substantial financial resources, technical human resources, and technical analytical resources. In some cases, the competitive procurement processes are very burdensome and take too long (e.g. NYISO). Moreover, in evaluating proposals ISOs place a lot of weight on engineering, operating, siting, and environmental permitting *experience*. However, we should remember that the U.S. has a large number of utilities with a century of transmission construction and operating experience. They can form subsidiaries and participate in planning and competitive procurement processes outside of the areas where they have retail footprints to satisfy Order 1000’s criteria for being a

non-incumbent. Indeed, most of the non-incumbents participating in competitive procurement processes are subsidiaries of large experience utilities, existing independent transmission companies, or independent power companies. Accordingly, there is no shortage of actual and potential non-incumbent transmission development competitors. It is clear from the competitive procurement examples that I discussed above that there are typically several competing developers that submit proposals for the same project --- as many as 12.

Incumbents may have inherent advantages in some situations. They are already invested in a regional planning process, especially in the ISOs, have years of experience with it, and have no real choice but to devote resources to it. Incumbents also may have eminent domain rights, rights of way, and other soft assets that are difficult for a non-incumbent to obtain. Finally, building new transmission projects may confront community opposition of various forms. Long historical experience dealing with state and local governments and regional interest groups may convey a natural advantage. Finally, there are some types of transmission projects which may simply be easier for an incumbent to design, build and operate. An example is the upgrade of a substation to accommodate expansion of connected transmission lines. Both New York and SPP reserved substation upgrades to the incumbent in designing a competitive procurement process for new line construction. A substation project in California that was put up for competitive procurement received one bid and it came from the incumbent.

FERC has placed great weight on open transmission planning processes, the end of any federal right of first refusal, and the participation on non-incumbents and other stakeholders in the planning process through orders 890 and 1000. But, has opening up the transmission planning process to non-incumbents and other stakeholders changed how project choices are made and expanded opportunities for non-incumbents? This is, of course, very hard to know, since there is

no natural experiment or controlled trial, and associated comparative benchmark data, to rely upon. We can ask the qualitative question of whether or not these changes have opened up additional opportunities, beyond those created by formal open competitive bidding structures.

One way to get a sense for the answer to this question is to examine whether transmission companies that pursue projects through open competitive bidding are also designated as non-incumbent developers through the regional planning process when there is not a formal open competitive procurement process. NextEra Energy Transmission, a subsidiary of NextEra Energy, which is the largest electric power company in the country by market value, has been active as a competitive transmission developer. It is typically a non-incumbent. Its website notes projects won in California, New York, Texas, and Ontario where development rights were secured through competitive procurement (in the California and New York projects are in the RFPs discussed above). NextEra Energy Transmission's web site lists the transmission projects it is developing in the U.S. The only new development projects listed are those it secured through competitive procurement. The other projects are existing projects that it acquired from another owner. LS Power is also a major player in the competitive transmission procurement arena.<sup>82</sup> It is typically a non-incumbent in competitive transmission procurement processes. It was selected to develop four projects through competitive procurement processes in CAISO, PJM, MISO, and ERCOT. The fifth project is in Nevada. The Nevada project was not selected through a formal open competitive procurement process. It is being developed with a Department of Energy Loan Guarantee and the incumbent owns 25% of the project. Transource, a subsidiary of American Electric Power, also submitted bids in open competitive procurement programs. Its website lists two projects in PJM (two of the non-incumbent projects discussed above) and two additional projects in Missouri. One

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<sup>82</sup> <https://www.lspower.com/project-map/>

is pre-order 1000. The second was developed with a partner which owns an incumbent which appears to have been the initial developer of the project.<sup>83</sup> While this is hardly an exhaustive survey, it does not appear that merely opening up the transmission planning process to non-incumbents and removing the right of first refusal has yet led to a lot of business for non-incumbents.

## VI. Conclusions

What I have called the “competitive transmission procurement model” is a framework that expands the role of competition in the development and potentially operation of transmission projects. FERC Order 1000 gave new life to this model. Competitive procurement for incumbents and non-incumbents and opportunities for non-incumbents to participate in regional transmission planning and project selection have increased. The progress has been slow but promising. There is still much to be done.

It is evident from the limited evidence that we have that competitive procurement can help to resolve the adverse selection and moral hazard problems faced by regulators, in this case FERC. If we view the evidence to date as a kind of experiment, it suggests that there are potential efficiency gains from expanding open competitive solicitation opportunities meeting certain criteria. Yes, only a tiny fraction of transmission projects authorized in the U.S. are being selected through formal competitive procurement solicitations with transparent evaluation criteria. ISOs have adopted a wide variety of criteria to exclude and include projects from competitive procurement. PJM’s more open process mostly led to projects being awarded to incumbents. It seems like a lot of time and effort for three projects out of 142 awarded to go to non-incumbents.

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<sup>83</sup> <https://www.cfra.org/nebraska-city-maryville-sibley>; [https://journalstar.com/business/local/new--mile-power-line-from-nebraska-city-to-missouri/article\\_7413e390-d12c-5660-bf93-86d4586326c1.html](https://journalstar.com/business/local/new--mile-power-line-from-nebraska-city-to-missouri/article_7413e390-d12c-5660-bf93-86d4586326c1.html)

Given the lack of experience with competitive procurement in the U.S. it may have been prudent for FERC to make competitive procurement by ISOs voluntary in Order 1000 and for ISOs to limit the kinds and number of projects selected in this way. However, the experience to date is sufficiently promising to consider expanding the use of open competitive procurement solicitations for transmission projects.

How might this be accomplished? FERC can do more to encourage competitive procurement than has been the case today. It could add an incentive to the existing list of incentives to reward projects selected through an open competitive procurement process, providing both incumbents and non-incumbents with incentives to support expansions of competitive procurement by the ISOs. FERC could also take a more favorable and supporting posture toward including cost containment and other performance incentives in projects selected through competitive procurement, provide guidance to ISOs regarding evaluation of performance commitments, amend OATTs to clearly allow ISOs to take cost containment commitments into account, and provide more transparent guidance for how cost containment provisions will be included in the revenue requirements calculation process.

FERC could also play a more active role in providing guidance to the ISOs for specifying criteria for transmission projects that are likely to be good candidates for competitive procurement. At this stage, excluding projects that are highly likely to be upgrades to existing facilities,<sup>84</sup> below a certain voltage, subject to local rather than regional planning criteria, below an estimated cost threshold, etc., would make sense if it is combined with stronger FERC support for expanding

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<sup>84</sup> This would require changes to the PJM process. The PJM staff and the TEAC would have to identify projects up-front where the most cost effective solution is likely to be an upgrade to existing facilities. Competitive procurement would then apply when greenfield projects are identified as having a high probability of being the most cost-effective solution or where the staff is uncertain about whether a greenfield or an upgrade is likely to be the best solution.

competitive procurement for the remaining types of projects. This would lead to more projects being authorized through a competitive procurement process.

Finally, as this experiment with competitive procurement evolves, it would make sense to design an evaluation program that accompanies the experiment. This would require the publication of more transparent evaluation criteria, publication of more transparent information about how these criteria were applied to support the selections, standardization of public information requirements, and information tracking of performance of projects selected through competitive procurement. With the right information in hand both FERC staff and stakeholders would be in a position to evaluate the performance of competitive procurement and help to lead to a set of best practices.

## DATA APPENDIX

Collecting the information for this paper was not an easy task. Aside from data on the number of competitive solicitations, the numbers of bidders, and a breakdown of incumbent vs. non-incumbent winners for the 2013-2016 period contained in FERC (2017) and collected from ISO web sites there is no organized repository and no standard presentations of information for ISO competitive transmission solicitations. Neither FERC nor state regulators have evaluated the competitive procurement programs. Accordingly, I started with FERC (2017) and then searched the web sites of all of the ISOs for relevant information on transmission planning, competitive procurement, and compliance with orders 890 and 1000. This information was supplemented by searches of contemporaneous reports in the trade press and local media. Johannes Pfeifenberger and his colleagues at the Brattle Group were kind enough to share their experience, study presentations, and information with me. This enabled me to compare the information that I found with what they found regarding competitive transmission procurement. Craig Glazer and Suzanne Glatz of PJM were kind enough to arrange for the data that I had collected for each PJM RTEP window to be checked. I went back to the source information to check the small number of differences that were identified and the results from this process appear in Table 2. I am confident that I have found all of the competitive procurements initiated by the ISOs and the associated available information for the period 2013-2018. Most of the primary source documents can be found in footnotes in this paper. Any remaining errors are entirely my responsibility.

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