February 6, 2023

SB 68 - Providing incumbent electric transmission owners a right of first refusal for the construction of certain electric transmission lines.

Oral In-Person

Proponent

FROM:
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TO:
Senate Utilities Committee

Testimony of ITC Great Plains, LLC In SUPPORT of Senate Bill No. 68 Before Senate Committee on Utilities February 6, 2023

Brett Leopold

Chairman Olson & Committee members, my name is Brett Leopold, President of ITC Great Plains, and I want to express my appreciation for the opportunity to speak to you about Senate Bill 68.

ITC Great Plains is a state-certificated independent transmission company that owns and operates approximately 450 miles of high voltage transmission lines in Kansas. At the time we received our Kansas certificate in 2007, the Kansas Corporation Chairman announced that we were probably the first new Kansas public utility in 100 years. ITC Great Plains is a subsidiary of ITC Holdings, which owns, operates, and maintains electric transmission systems and assets across 7 states in the Midwest and Great Plains region, serving over 25,000 MW of connected load, and operating over 16,000 miles of electric transmission lines. ITC Great Plains is headquartered in Topeka, and has offices in Wichita and Dodge City. Our company is a deeply committed and engaged corporate citizen in the towns and counties where we work and do business. In 2015, we were nominated by Ford County Economic Development for the Kansas Governor's Award of Excellence, which is the highest award given to a business by the state, and ITC Great Plains was chosen by the Department of Commerce and received the Governor's Award of Excellence as business of the year.

It is important to understand that SB 68 is very limited in scope and applies only to the first right to build a specific category of high-voltage regional SPP transmission projects. It does not prevent new companies from acquiring, operating and maintaining existing transmission from utilities in the state, subject to applicable existing regulation and laws. And it does not preclude developers from partnering with Kansas utilities to build, own and operate new transmission in the state. ITC's founding CEO, Joe Welch, a native of Arma and graduate of KU, came to

Kansas to collaborate with local utilities on transmission development and construction with the encouragement of the Kansas Electric Transmission Authority under the leadership of Chairman Carl Holmes in 2006. For several years, ITC Great Plains did not build or own any transmission in the state, but rather, collaboratively engaged with Kansas utilities serving the retail customers, state and local government officials, the Southwest Power Pool, the KCC and other stakeholders to identify transmission solutions that could best serve these entities and their customers. Ultimately, ITC partnered with Sunflower and Midwest Energy to build SPP-planned and approved transmission projects with great value to the state and the region, but only because Kansas entities saw value in serving their customers through a partnership with ITC. This is very different than a federally-administered process that selects and dictates an entity to build transmission where that entity may have no connection or relationship with Kansas utilities and the customers that they serve. While Order 1000 has been in effect, ITC and other non-incumbent transmission owners have successfully negotiated transmission acquisition agreements, development agreements and partnerships with utilities in Kansas and elsewhere in the SPP region. In that manner, there is already very meaningful competition for transmission development, construction and ownership in Kansas under pre-existing state and federal law. That is already happening today and can continue if SB 68 is adopted.

The legislation before this committee is critical to address the failed and harmful federal regulation known as Order 1000, and specifically the transmission developer solicitation process that the Federal Energy Regulatory Commission (FERC) mandated in that order. Adopted in 2011, FERC's Order 1000 removed the Right of First Refusal for transmission owners to develop new transmission facilities that connected to their existing transmission systems. This right of first refusal had long been utilized by Regional Transmission Organizations (or "RTOs"), like the Southwest Power Pool ("SPP) to expeditiously direct transmission owners to construct critically necessary transmission facilities, and recognized that established transmission owners are best positioned to efficiently expand and reliably maintain additions to their existing transmission systems. Instead of continuing this long-standing successful practice, Order 1000 mandated that RTOs administer a federally-mandated and controlled solicitation process to choose the developers that would construct these new facilities in the states. This substantially disrupted the transmission planning processes of SPP, which had long fostered efficient transmission development to the benefit of Kansas electric customers, and lead to similar negative outcomes in other RTOs.

After nearly 12 years of experience with this federal regulatory experiment in the states, the available evidence conclusively demonstrates that the Order 1000 solicitation approach has failed, and is doing far more harm than good to customers. Not only does it substantially delay the planning and construction of transmission at a time when transmission is absolutely critical to delivering reliable low-cost generation to customers, but it also has failed to achieve the projected cost savings that it was predicted to create and upon which its issuance was based. Although Order 1000 is a federally mandated policy, we want to be clear that contrary to what you might have heard or will hear, states can resolve this issue and retake control of utility infrastructure planning within their own borders. Recognizing from its inception that this federal mandate would be controversial and unacceptable to many states, Order 1000 included an express provision to reject federal regulation and opt out by implementing state Right of First Refusal legislation, allowing states to return to the status quo.

When Order 1000 was first adopted, it presented an intriguing concept to much of the industry. I want to emphasize that ITC and other transmission owners have given FERC's approach a fair chance – in fact, ITC even went as far as to oppose legislation like this back in 2014 as Order 1000 had not yet been fully implemented and tested in most planning regions. But as time has passed, ITC has recognized that this policy is actually detrimental to building transmission, due, in part, to the uncertainty and delays it causes. The Southwest Power Pool did not even issue its first RFP for a project until May 2015. That first Order 1000 project was in southwest Kansas. For nearly a year, developers and the Southwest Power Pool spent extraordinary amounts of money and time to prepare RFP responses and to participate in and administer a bureaucratic process to determine who would build and own that transmission line. In April 2016, the project was awarded by the Southwest Power Pool, and thereafter, it was restudied and determined that the project was not needed. It was never built. This ineffectual, lengthy process was the first indicator of the dysfunction that federal regulation would bring to the planning and construction of transmission in Kansas and the SPP. Under the best of circumstances, it is a lengthy process to plan, approve and build these important transmission projects. In recent years, the first set of Order 1000 projects around the country have finally been completed and placed into service. Evidence from the full implementation of Order 1000 demonstrates the federal process is not delivering the promised benefits to the states.

Most notably, Order 1000's federally mandated solicitation processes have failed in the following areas:

- Studies of transmission projects, which were subject to Order 1000 and have been placed in-service, show a pattern of cost overruns and/or delays which are borne by transmission customers, resulting in an inability for out-of-state developers to deliver the project costs and implementation timelines they claim they can achieve. Even projects which achieve their nominal in-service dates are still necessarily delayed in development by the additional time required to conduct the solicitation. It is important to recognize that delay in the planning, approval and construction of beneficial transmission projects delays the delivery of benefits to customers and costs them money.
- The Order 1000 process puts constraints on collaboration and partnership amongst SPP transmission owners during the project planning, developing, and construction process. It drives more short-term solution and drives more transmission investment on a just-in-time, incremental basis, rather than on a more efficient, comprehensive, and regional basis. There are significant benefits for Kansas customers produced by the construction of high voltage regional projects that are cost allocated to the entire SPP region. A properly identified and planned 345kV line that is regionally cost allocated can eliminate the need for numerous low voltage lines that are only a short-term solution, with between 66 and 100% of the costs being allocated to Kansas customers.
- Even if Day One construction costs are low for a new transmission line, the line must be maintained and operated for decades at continuing expense that is charged to Kansas

customers. Bidders are incentivized to be aggressive in their designs and material choices to maximize the chance to win a project. While that may seem positive, a less robust choice of design and materials can cost the customers much more over the life of the project to maintain, rebuild and operate. In some instances, bidders have chosen to commit to artificial caps on operations and maintenance expenditures for the life of the project, irrespective of what may eventually be needed to maintain the facility in a reliable and resilient manner. If future maintenance needs outstrip the artificial limits set in the bid, the developer has two choices – either it can forgo or reduce the necessary maintenance work to avoid losing money, or it can include in its bid an exception to the cap, which, given the increasing frequency of extreme weather events, renders the promised cap essentially meaningless. Indeed, many aspects of nominally firm cost caps which have been selected in Order 1000 processes contain extensive exceptions which permit cost increases for relatively common occurrences in project development, such as a state regulator's routing decisions or storm damage rebuilds. Some Order 1000 projects which have been placed in-service at a final cost more than the promised bid amount have done so because these cost cap exceptions have been triggered, meaning that transmission customers have borne the cost.

- Projects have the potential to be awarded to transmission developers with little, if any, local presence in Kansas, and no connection or relationship to the retail customers. These developers may have inferior ability to dispatch crews to resolve outages and to otherwise maintain transmission lines at the same level that well-established Kansas transmission owners do. Out-of-state developers may have financial backers who push for transmission facilities to be sold to unknown third parties if profits, changes in business priorities, or other financial considerations dictate.

These types of problems are distressingly common across many planning regions, and even now FERC's current commissioners have begun to publicly recognize and comment on these failures. Fortunately, Kansas does not need to wait indefinitely for the federal government to reinstate the ROFR and fix all these problems, and instead can join numerous other states in rejecting Order 1000's federal mandates by adopting Senate Bill 68.

By adopting this bill, Kansas can stand up against federal overreach and stand up for the needs of Kansas electricity customers.

I thank the committee for its time and am happy to answer any questions you may have.

Benefits of Right of First Refusal Legislation
(Kansas Senate Bill 68)

Brett Leopold, President
ITC Great Plains

A FORTIS COMPANY

FOR THE GREATER GRID

ITC GREAT PLAINS

ITC Great Plains

- Established 2006
- ~470 miles of line serving Kansas and Oklahoma
- 138kV - 345kV range
- Capital investments: ~$568M to date

ITC A FORTIS COMPANY | FOR THE GREATER GRID.

ITC GREAT PLAINS: Key Projects

KETA Project
- 174 circuit miles, 345 kV
- Completed 2012

Elm Creek-Summit
- 30 circuit miles, 345 kV
- Completed 2016

Kansas V-Plan
- 244 circuit miles, 345 kV
- Completed 2014

Hugo-Valliant
- 18 circuit miles, 345 kV
- Completed 2012

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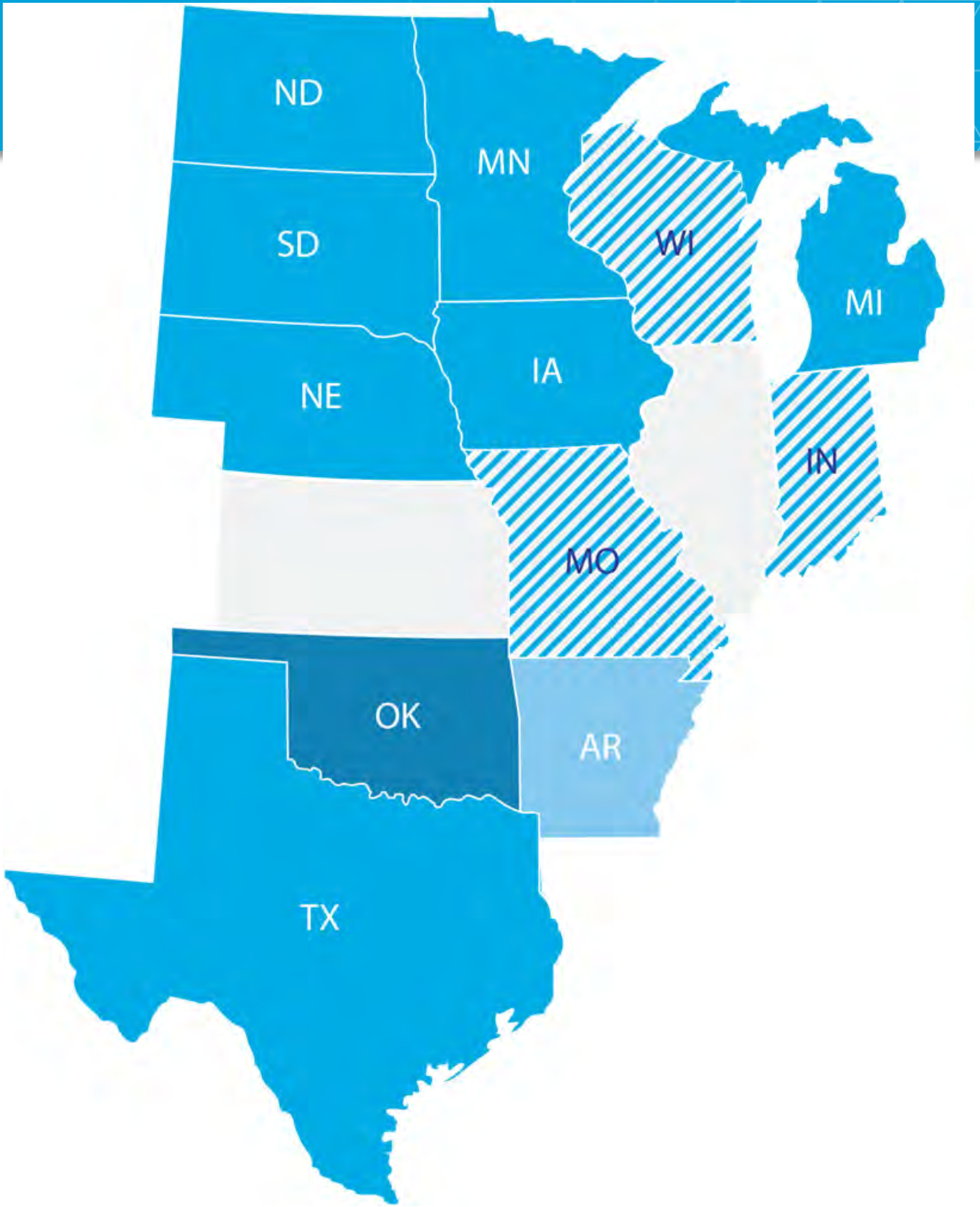
ROFR LEGISLATION IN PLACE IN MULTIPLE STATES



STATES WITH ROFR LEGISLATION

- sub-300kV
- blanket ROFR
- introduced within last 2 years

Study Shows Order No. 1000 Transmission Solicitations Have Not Yielded Customer Savings or Improved Transmission Development Timelines

NEWS PROVIDED BY
ITC Holdings Corp. →
Aug 16, 2022, 13:26 ET

Concentric Energy Advisors report reveals significant shortcomings accompany 'competitive' solicitations for regional transmission projects

NOVI, Mich., Aug. 16, 2022 /PRNewswire/ -- ITC Holdings Corp. (ITC) and other members of the Developers Advocating Transmission Advancements (DATA) Coalition are calling attention to a new study showing that unintended consequences of the Federal Energy Regulatory Commission's (FERC) Order No. 1000 include project cost increases and schedule delays.

The study titled "Competitive Transmission: Experience to Date Shows Order 1000 Solicitations Fail to Show Benefits" prepared by Concentric Energy Advisors, reveals that completed and active competitive transmission projects awarded to non-incumbent developers experienced an average of 12 months in schedule delays and 27% in cost increases, contrary to promises made by competitive developers in winning bids.

Ten years ago, FERC issued Order No. 1000 in response to the growing challenge of planning and constructing new transmission to keep pace with national and state energy policy priorities. The order allows for public utility transmission providers to use competitive bidding to solicit transmission projects or project developers. Now a decade later, new emerging data of so-called "competitive projects" now in service, or in advanced stages of development, show significant shortcomings.

Using six projects awarded to developers through competitive solicitations, the study investigated claims that Order No. 1000 solicitations contribute to cost savings and the timely development of transmission infrastructure.

- One project from New York Independent System Operator's service territory experienced a 67% cost increase above the developer's promised cost cap, which is now attempting to be recovered from customers. This calls to question whether competitive processes create incentives for outside developers to submit overly aggressive bids to win projects.
- Another example from the Midcontinent Independent System Operator (MISO) region found that the final cost for a competitive project was approximately equal to MISO's planning-level cost estimate and the average of all the submitted bids, indicating no benefit from the solicitation.

For the first time, these case studies provide policymakers the most accurate assessment of the Order No. 1000 competitive process.

"These results add to the growing case that it is time to move in a new direction," said Nina Plaushin, Vice President of Regulatory and Federal Affairs at ITC and DATA Coalition member. "As FERC considers new reforms to regional transmission planning processes, it is clear we must return to a collaborative planning model that has been proven to result in cost effective transmission infrastructure. At a time when transmission investment is sorely needed to power our transition to a clean energy economy and achieve the nation's climate goals, there is no time to waste."

The study was prepared on behalf of the DATA Coalition, a group of transmission-owning utilities consisting of Ameren, Eversource Energy, Exelon Corporation, ITC Holdings Corp., National Grid USA, Public Service Electric and Gas Company and Xcel Energy.

ABOUT ITC HOLDINGS CORP.

ITC Holdings Corp. is the largest independent electricity transmission company in the United States. ITC provides transmission grid solutions to improve reliability, expand access to markets, allow new generating resources to interconnect to its systems and lower the overall cost of delivered energy. Through its regulated operating subsidiaries ITC*Transmission*, Michigan Electric Transmission Company, ITC Midwest and ITC Great Plains, ITC owns and operates high-voltage transmission infrastructure in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma, and in development in Wisconsin. These systems serve a combined peak load exceeding 26,000 megawatts along 16,000 circuit miles of transmission line, supported by 700 employees and 1,000 contractors. ITC is based in Novi, Michigan. For further information visit **WWW.ITC-HOLDINGS.COM**. ITC is a subsidiary of Fortis Inc., a leader in the North American regulated electric and gas utility industry. For further information visit **WWW.FORTISINC.COM**.

About Concentric Energy Advisors

Concentric Energy Advisors specializes in management consulting and financial advisory services focusing on the North American energy and water industries. Through its subsidiaries, CE Capital Advisors and Concentric Advisors ULC, Concentric provides capital market advisory support and consulting services in Canada.

SOURCE ITC Holdings Corp.

COMPETITIVE TRANSMISSION

Experience To-Date Shows Order No. 1000 Solicitations Fail to Show Benefits

Prepared on Behalf of the DATA Coalition: Ameren Services, Eversource Energy, Exelon Corp., ITC Holdings Corp., National Grid USA, Public Service Electric and Gas Company, Xcel Energy

August 2022

CEADVISORS.COM

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I. INTRODUCTION & EXECUTIVE SUMMARY

The value of electric transmission is significant and well documented. Transmission infrastructure provides an essential link between the sources that generate electricity and the customers who expect a reliable and resilient source of power at a reasonable cost. Transmission enables production cost savings and emissions reductions, reduces losses, and increases access to lower cost generation resources for the benefit of customers.

As the power grid continues to transition to one that is increasingly reliant on intermittent resources to meet demand for clean power, the role of transmission in delivering the output from these renewable resources has never been more critical. Over a decade ago, the Federal Energy Regulatory Commission ("FERC" or "Commission") sought to spur transmission investment by promulgating Order No. 1000. Among other things, Order No. 1000 sought to open the transmission space to competitive bidding processes, under the assumption that these processes would encourage innovation and cost savings. Since that time, proponents of transmission competition have argued that significant cost savings can be achieved through competitive bidding processes; however, there has been very little real-world data on completed projects to validate these assertions.[1] Now, ten years later, this data is beginning to become available for analysis. As policymakers consider how to promote the development of needed transmission and all its associated benefits to customers, it is critical that the real-world experience with competitive transmission be brought to light.

As shown below, a review of competitive projects that are now in service or in advanced stages of development clearly demonstrates that Order No. 1000 competitive solicitations have not been successful in driving cost savings and have added delays to the development of transmission infrastructure. Competitive solicitations added as many as 1000 days to the development of transmission projects, and many experienced cost escalations, further questioning the value of competitive solicitations.

1 Concentric's report, "Building New Transmission" dated June 2019, showed that incumbent transmission owners have successfully controlled costs for transmission projects that they have undertaken.

TABLE 1: CASE STUDY COST SUMMARY

NAME	REGION	REGION'S COST ESTIMATE ($M)	WINNING BID COST ESTIMATE ($M)	FINAL COST OR CURRENT ESTIMATE ($M)
Empire State	NYISO	NA	181	249
Artificial Island	PJM	NA	146	149.5
Duff Coleman	MISO	58.9	49.8	54.2
Delaney to Colorado	CAISO	325	300	389
Suncrest	CAISO	50-75	42.3	53
Harry Allen to Eldorado	CAISO	120[2]	144	202.4

On the critical question of whether transmission competition saves customers money, the results from key projects are now clear: in some cases, competitive project costs have escalated significantly against initial estimates provided in the selected proposals, as developers utilize exceptions to cost caps and guarantees to recover higher than expected costs. In other cases, final project costs for competitive projects appear in line with cost proposals from other submitted bids and initial planning estimates, raising questions about whether the competitive bidding process resulted in lower costs, particularly if the costs of administering the competitive processes and the costs of preparing the bids are factored in. Whereas, incumbent TOs have demonstrated the ability manage project costs effectively even without imposed price caps.[3] The conclusions drawn here are based on publicly available information and the public reporting of final or projected-final project costs. In many cases, transparency on this data is limited.

The competitively bid projects examined here have experienced a range of challenges, including:

- Schedule adherence - several projects experienced significant scoping and schedule adherence challenges, due to route changes and other construction delays. Other projects experienced planning issues, significantly delaying in-service dates and far exceeding project deadlines, which carries a real cost in delayed benefits to customers. On average, the examined projects were delayed approximately a year beyond the required in-service date, as demonstrated below in Table 2. Three of the six case studies experienced delays to service of over a year, and two projects have run more than two years behind schedule.

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2 CAISO, 2013-2014 Transmission Plan, July 16, 2014, p. 252.

3 Building New Transmission, Concentric Energy Advisors, inc., June 2019.

Table 2: CASE STUDY DELAYS TO SCHEDULE

NAME	REGION	REQUIRED IN-SERVICE DATE	IN-SERVICE DATE	DELAY TO SCHEDULE
Empire State	NYISO	June 2022	July 2022	1 Month
Artificial Island	PJM	April 2019	May 2020	1 Year 1 Month[4]
Duff Coleman	MISO	January 2021	June 2020	NA
Delaney to Colorado	CAISO	May 2020	NA	2+ Years[5]
Suncrest	CAISO	June 2017	February 2020	2 Years 8 Months
Harry Allen to Eldorado	CAISO	May 2020	August 2020	3 Months

- Significant cost overruns - Several projects have experienced significant cost overruns due to factors which may have been foreseen (and potentially avoided) by experienced incumbent TOs, such as: regulatory delays, re-routing, and other environmental challenges. In some instances, cost containment provisions have offered little protection against cost increases due to the use of exclusions that allow developers to recover the costs of major cost escalations.
- New entry - While Order No. 1000's objectives include encouraging new developer market entry, the number of discrete developers competing in each ISO/RTO's competitive solicitations examined appears to have remained relatively constant even in recent solicitations. This suggests that FERC's desire to open the development of transmission infrastructure to a broader set of participants has not been fulfilled.
- Administrative costs - The costs associated with preparing bids submitted in the competitive solicitations are significant, as are the costs incurred by the ISOs/RTOs in administering these competitive processes.
- Operational performance issues – One project experienced a sustained derate since entering commercial operation, effectively limiting the transmission benefits that would have inured to the benefit of ratepayers had these derates been avoided. The Artificial Island reliability derate raises questions about project design and potential adverse incentives created by the solicitation process; however, the reasons for the derate have not been made public.

4 PJM's initial in-service date was April 2019. Due to challenges throughout the process that are discussed in Section V, the project was suspended and rescoped. PJM's updated in-service date was June 2020.

5 The Delaney to Colorado River Project is expected to enter service in 2023, indicating an overall delay close to three years.

Reliability performance is a function of many factors and is not specific to non-incumbent developer status.

Given that the timely development of transmission is critical for meeting clean energy goals and improving system resilience, these case studies offer a clear indication that the competitive bidding of transmission development under Order No. 1000 has not provided the expected benefits.[6]

The remainder of this report is organized as follows: this section includes an executive summary describing our findings from a review of competitive solicitations conducted to-date. Section II provides a background on federal policy related to transmission development. Section III provides a brief overview of competitive transmission solicitations to date. Section IV provides a brief discussion of how case studies were selected, and Section V provides detailed information on those six competitive transmission case studies. Section VI provides our findings and conclusions.

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6 Americans for a Clean Energy Grid (ACEG), Planning for the Future, FERC's Opportunity to Spur More Cost-Effective Transmission. January 2021. https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf

II. Background on FERC Order 1000

A. History

In 2011, the FERC issued Order No. 1000 in response to the growing challenge in the United States of planning for and constructing new transmission to keep pace with national and state energy policy priorities. Order No. 1000 addressed three fundamental reforms affecting transmission planning: regional transmission planning reforms, cost allocation reforms, and non-incumbent developer reforms related to the right of first refusal ("ROFR"). Regional transmission planning reforms involved designing regional planning processes that considered public policy, economic and reliability needs. Cost allocation reforms required each of the FERC-approved planning regions, including the six FERC-jurisdictional independent system operators ("ISOs") and regional transmission organizations ("RTOs"), to develop methodologies to comply with certain principles by which costs for the projects identified in their transmission plans would be allocated to entities in the region based on a "beneficiary pays" approach. Finally, and importantly, Order No. 1000 removed incumbent transmission providers' ROFR for a transmission facility selected in a regional transmission plan for purposes of cost allocation, subject to certain limitations. Under a ROFR system, incumbent utilities have the exclusive right to build, maintain and own transmission lines located within their service territory. The Order No. 1000 ROFR reforms applied only to regionally cost-allocated projects—local projects, for example, were exempted.

B. Objectives

Federal and state lawmakers and regulators have passed a host of laws and regulations in recent years with significant impacts on generation mix and future transmission needs. These policies have included the promotion of renewable energy, energy efficiency, and demand response. With the increasing role of renewables and customer-focused technologies, FERC acknowledged that existing orders regarding transmission did not provide regional planners adequate direction as to how to consider these new technologies. As a result, new transmission development was lagging behind need in many areas. Order No. 1000 attempted to update transmission planning to cope with these ongoing changes to the power industry and the energy regulatory landscape by setting forth several major new requirements. The objectives of Order No. 1000 are detailed on the FERC's website:

Order No. 1000 is a Final Rule that reforms the Commission's electric transmission planning and cost allocation requirements for public utility transmission providers. The rule builds on the reforms of Order No. 890 and corrects remaining deficiencies with respect to transmission planning processes and cost allocation methods. In addition to planning and cost allocation reforms, Order No. 1000 contained important reforms involving non-incumbent transmission developers as detailed below:

- 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: This does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation. 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.
- 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.
- 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.[7]

On April 21, 2022, the FERC issued a Notice of Proposed Rulemaking ("NOPR") that reiterated the objectives it sought to achieve under Order No. 1000:

> *Accordingly, we preliminarily find that, while Order No. 1000's nonincumbent transmission developer reforms have a sound theoretical basis in requiring the elimination of all federal rights of first refusal for entirely new transmission facilities selected in a regional transmission plan for purposes of cost allocation, the remedy prescribed by Order No. 1000 failed to recognize that at least some of the most notable expected benefits from competitive transmission development processes (e.g., new transmission developer market entry, greater innovation in and potentially lower costs of transmission development) could be achieved or at least reasonably approximated through other means.*[8]

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7 "Order No. 1000 – Transmission Planning and Cost Allocation," FERC, accessed June 30, 2022. https://www.ferc.gov/electric-transmission/order-no-1000-transmission-planning-and-cost-allocation

8 FERC NOPR April 2022 RM21-17-000, para. 353.

As FERC considers potential revisions to the Order No. 1000 framework outlined in the April 21 NOPR, it is worthwhile to consider whether the "expected benefits from competitive transmission development processes" cited above have actually materialized. This, in turn, can help to guide the Commission's efforts to implement a policy framework that results in the development of needed transmission infrastructure and associated benefits to customers. As described in detail below, the available case study data represents that competitive bidding for transmission has not delivered benefits to customers, and the costs and risks far outweigh any perceived benefit from this process.

III. EXPERIENCE WITH COMPETITIVE TRANSMISSION

A. US EXPERIENCE WITH COMPETITIVE TRANSMISSION PROJECTS

In implementing Order No. 1000, planning regions have adopted varying approaches to integrating the transmission planning process with the mandated competitive solicitation process. The design of the competitive solicitation process used by the California Independent System Operator ("CAISO"), the Midcontinent Independent System Operator ("MISO"), and the Southwest Power Pool ("SPP") involves identifying 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 request for proposals ("RFP") is then developed for projects meeting the specified criteria. Economic projects that were delayed due to Order No. 1000 competition represent a lost benefit to ratepayers due to that delay. The specific projects are put out for competitive bidding, with competition being largely limited to the construction and ownership of the project. The FERC refers to this model as a "competitive bidding" model.

Alternatively, the PJM Interconnection ("PJM"), ISO New England Inc. ("ISO-NE") and the New York Independent System Operator ("NYISO") use the transmission planning process to identify specific reliability, market efficiency, and public policy "needs."[9] The competitive process then allows bidders to specify proposed transmission projects that meet these needs. The FERC refers to this as a "sponsorship" model. Arguably, this model gives the competitive procurement process a 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/RTO and then subject to competitive procurement. However, NYISO and PJM have applied the sponsorship model quite differently. In principle, the PJM Regional Transmission Expansion ("RTEP") planning process and the associated competitive "windows" provide a greater number of opportunities for incumbents and non-incumbents to compete for reliability and market efficiency projects as compared to the NYISO, which has designated only three large "public interest" needs for which competitive solicitations have been initiated.

9 ISO-NE has had only one competitive solicitation to-date, which was held in 2020. This project has not yet begun construction.

In practice, the number of competitive solicitations that have been initiated has been relatively modest. Over the past decade, 25 competitive transmission projects have been carried out with approximately 75 discrete developers submitting over 800 proposals.[10]

- CAISO has had ten competitive transmission projects awarded since 2017, with nonincumbent developers making up over 65% of discrete entities involved in both cases.
- NYISO received proposals from a higher percentage of incumbent developers for its 2020 NY AC Docket Project, while observing a majority of nonincumbents submit bids for its other two competitive solicitations in the past five years.
- MISO has conducted two competitive transmission projects since 2016, and the majority of proposals were submitted by nonincumbent transmission developers.[11,12]

It is important when reviewing the competitive solicitations that have been conducted to-date to assess the number of non-incumbent transmission developers that have engaged in these processes. Since 2013, the number of discrete transmission developers in a given transmission planning region in any year has typically ranged from 3 to 6 entities. In 2016, the majority of the "incumbent proposals" received by NYISO were actually joint proposals between incumbent and non-incumbent developers.[13] This statistic is not surprising, since developing and constructing electric transmission infrastructure is not for small or inexperienced organizations. These activities require substantial financial resources, technical human resources, and technical analytical resources. In addition, the competitive procurement processes are burdensome and time consuming. The technical capability of developers, as well as their financial resources, are critical to their success in the competitive solicitations and ultimately completing the development of transmission.

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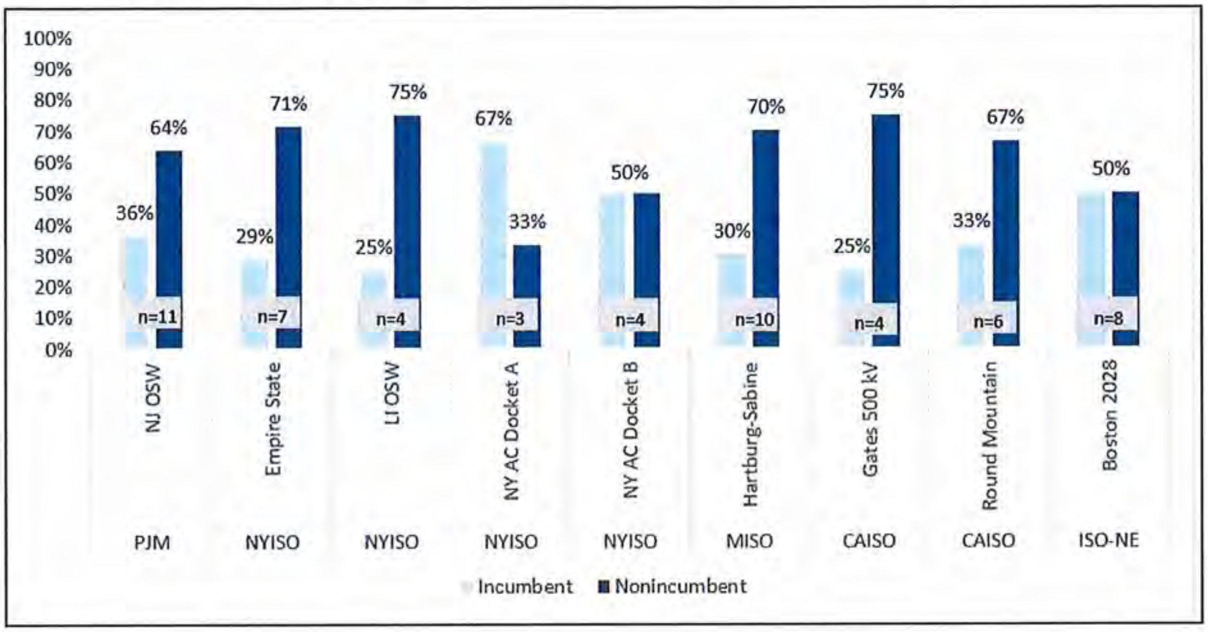
10 SPP Transmission Provider Public Reports, PJM Transmission Expansion Advisory Committee, NYISO Transmission Planning Need Reports, MISO Competitive Transmission Administration, CAISO Transmission Project Sponsor Selection Reports.

11 Department of Energy 2018 Transmission Data Review, p. 75.

12 MISO, Hartburg-Sabine Junction 500 kV Competitive Transmission Project Selection Report, November 27, 2018, p. 2.

13 Department of Energy 2018 Transmission Data Review, p. 75.

Figure 1: SUMMARY OF COMPETITIVE TRANSMISSION DEVELOPERS SINCE 2017[14,15]



B. SUMMARY TABLE OF COMPETITIVE SOLICITATIONS BY U.S. REGION

Competitive solicitations have been conducted in every ISO/RTO across the United States. Below is a summary of competitive solicitations conducted to-date.

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14 Figure 1 Sources: PJM Transmission Expansion Advisory Committee, NYISO Transmission Planning Need Reports, MISO Competitive Transmission Administration, CAISO Transmission Project Sponsor Selection Reports.

15 SPP only identifies bidder information at board meetings and does not provide data in reports, so SPP has been excluded from Figure 1.

Table 3: Competitive Solicitations by U.S. Region[16,17,18,19]

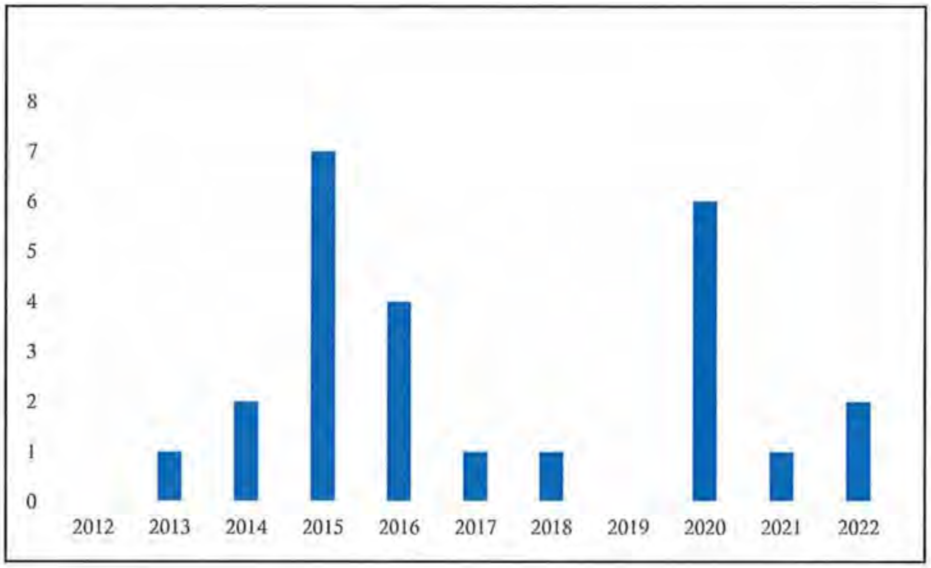
#	Project	Region	Winner	Year Awarded
1	Sycamore to Penasquitos	CAISO	SDG&E & Citizens	2014
2	Greg to Gates	CAISO	PG&E & BHE & Citizens	2013*
3	Suncrest Reactive Power	CAISO	NextEra	2015
4	Estrella Substation	CAISO	NextEra	2015
5	Miguel Reactive Power	CAISO	SDG&E	2014
6	Spring (Morgan Hill) Substation	CAISO	PG&E	2015
7	Wheeler Ridge Junction Sub.	CAISO	PG&E	2015*
8	Delaney to Colorado River	CAISO	Abengoa & Starwood	2015
9	Harry Allen to Eldorado	CAISO	LS Power	2016
10	Round Mountain	CAISO	LS Power	2020
11	Gates 500kV	CAISO	LS Power	2020
12	Duff to Rockport to Coleman	MISO	Republic Transmission (LS Power)	2016
13	Hartburg-Sabine Junction	MISO	NextEra	2018
14	Boston 2028 RFP (Mystic)	ISO-NE	Eversource & National Grid	2020
15	Thorofare Project	PJM	Transource WV	2015
16	Artificial Island	PJM	LS Power	2015
17	AP South	PJM	AEP/Transource	2016
18	PJM 2021 SAA NJ OSW	PJM	TBD	2022
19	North Liberal to Walkemeyer	SPP	Mid Kansas Electric Co	2016*
20	Wolf Creek to Blackberry	SPP	NextEra	2021
21	Sooner-Wekiwa 345kV	SPP	Transource MO	2020
22	Minco-Pleasant Valley-Draper	SPP	NextEra	2022
23	Western NY (Empire State)	NYISO	NextEra	2017
24	NY AC Docket Segment A	NYISO	LS Power & NYPA	2020
25	NY AC Docket Segment B	NYISO	National Grid & Transco	2020

As can be seen in Table 3 above, the CAISO accounted for almost half of the total competitive solicitations conducted to-date. On the other hand, only one competitive solicitation process has been conducted in ISO-NE since Order No. 1000 was implemented in 2011. In addition, almost half of the competitive solicitations to-date were performed in 2016 or earlier. Importantly, none of these

16 Includes PJM open window projects that resulted in a non-incumbent winner.
17 SPP's Butler-Tioga project has been excluded due to the withdrawal of the project prior to submission of proposals.
18 * Indicates projects that have been withdrawn or put on hold since selection.
19 This list does not include the numerous PJM open window solicitations.

competitive solicitations involved interregional transmission projects, which Order No. 1000 explicitly targeted to facilitate the future expansion of the transmission grid.

Figure 2: COMPETITIVE SOLICITATIONS AWARDED SINCE 2012[20]



[20] Includes projects that have been withdrawn or put on hold since selection. See * noted projects in Table 3.

IV. APPROACH TO CASE STUDIES

In assessing whether the goals of Order No. 1000, as discussed in II, have been realized through the competitive solicitation process, it is important to conduct a thorough analysis of these processes to examine some real-world examples of competitive solicitations in practice. Below we describe the screening criteria applied to the complete list of competitive solicitations conducted to-date, and the competitive solicitations that passed the screening criteria and warranted an in-depth analysis.

A. SELECTION METHODOLOGY

In order to select a final list of competitive transmission projects on which to conduct an in-depth examination, Concentric began with a complete list of Order No. 1000 competitive solicitations and applied the following three screening requirements:

1. Projects awarded to non-incumbent transmission developers;
2. Projects that are in-service or under construction;
3. Projects with an estimated total capex greater than $50 M.

The first criteria screened for projects awarded to non-incumbent transmission developers. Proponents of the ROFR elimination under Order No. 1000 have argued that cost savings will be realized as a result of the entry of non-incumbent developers into the transmission space. For these claims to be accurately assessed, it is important to review competitive projects that have been awarded to non-incumbent developers who were responsible for developing the project. We assume that whether or not a project developed by an incumbent TO was awarded as part of a competitive solicitation, it would experience the same outcome related to cost and schedule adherence as compared to had it been constructed pursuant to a ROFR. For these reasons we first screened based on non-incumbent transmission developer status.

Secondly, it is important to examine only projects for which there is enough data to make informed determinations about the results of the competitive process. Much of the debate around Order No. 1000 competition has centered around claims and commitments made by winning developers before projects are actually developed and constructed. However, early-stage projects do not reveal any information about how much the project will ultimately cost, as further examined in the report. Examining projects that are in service or in advanced development provides the best opportunity at identifying the success or failure of competitive solicitations in achieving cost savings and filters out projects that are too early in development to accurately draw conclusions about the benefits realized for customers.

Finally, we examined projects with an estimated cost of at least $50 million. We believe that the results of competition are more transparent and easier to observe across projects of a certain size, scope, and length of construction, and that these size determinants would be broadly represented through an initial cost threshold.

B. Selected Case Studies

The screening criteria discussed above yielded the six projects in the table below for which an in-depth analysis was conducted:

Table 4: Selected Competitive Solicitations by U.S. Region

Name	ISO/RTO	Responsible Developer	Estimated Cost > $50M	In Service Date
Empire State	NYISO	NextEra	Y	2022
Artificial Island	PJM	LS Power	Y	2020
Suncrest	CAISO	NextEra	Y	2020
Delaney to Colorado	CAISO	Abengoa & Starwood	Y	NA
Duff Coleman	MISO	Republic Transmission (LS Power)	Y	2020
Harry Allen to Eldorado	CAISO	LS Power	Y	2020

It is important to note that the in-depth analysis conducted involved the review of numerous documents and data points. Because the transparency and reporting requirements differ significant across regions, it is challenging to compare and analyze costs. Nevertheless, we have used best efforts to report on data reviewed and document the sources of this data.

V. CASE STUDY REVIEW

A. EMPIRE STATE LINE

i. Project Overview

In 2015, NYISO recognized a public policy need for enhanced transmission in Western New York.[21] Grid congestion had previously limited power flow in the region, preventing clean energy generation sites in Niagara and Ontario from delivering maximum output to the grid. The NYISO recognized the need for a transmission solution that would allow for increased deliveries from a major New York Power Authority ("NYPA") hydroelectric project and allow for increased renewable imports from Canada. Through the Public Policy Process in New York, the NYISO addresses transmission needs that are driven by public policy requirements identified by the New York Public Service Commission ("NYPSC"). In a July 2015 order, the NYPSC identified the relief of congestion in Western New York, including access to 2,700 MW from the Niagara hydroelectric facility and additional imports of renewable energy from Ontario, as a Public Policy Transmission Need.

ii. Competitive Solicitation

On November 1, 2015, NYISO issued a 60-day solicitation window to examine potential solutions for the identified Western New York transmission need. The NYISO received a total of 12 proposals from seven different developers.[22] The twelve proposals represented costs ranging from $157 – $487M, as shown in Table 5 below.

[21] NYPSC, Order Addressing Public Policy Requirements for Transmission Planning Purposes Case 14-E-0454, July 20, 2015, p. 9.

[22] NYISO, Western New York Public Policy Transmission Planning Final Report, October 17, 2017, p. 15.

Table 5: INDEPENDENT THIRD-PARTY COST ESTIMATES FOR WESTERN NY PROPOSALS[23]

Project ID	Independent Cost Estimate ($2017)
T006	$ 157
T007	$ 278
T008	$ 356
T009	$ 487
T011	$ 177
T012	$ 433
T013	$ 232
T014	$ 181
T014_Alt	$ 219
T015	$ 159
T015_Alt	$ 197
T017	$ 299

NYISO Staff developed a draft Western NY Report detailing the results of its analysis. The draft report was reviewed with stakeholders in five Electric System Planning Working Group ("ESPWG") and Transmission Planning Advisory Subcommittee ("TPAS") meetings and was revised and clarified based on stakeholder and developer feedback.

Pursuant to the NYISO Open Access Transmission Tariff ("OATT"), NYISO Staff then submitted the Western NY Report to the NYISO Board of Directors for its review and action. Based on its review, the Board selected NEETNY Project T014 to address the Western NY Need, finding that NextEra's Project T014 was both the more efficient and more cost-effective transmission solution to address the Western NY Need based on its total performance across the selection metrics and scenarios. As the selected developer, NextEra is eligible to allocate and recover the costs associated with its Project T014 to the extent permitted under the NYISO OATT.

As outlined in the 2017 NYISO Selection Report, NEETNY proposed to construct two new 345kV substations, located in Elma and Royalton NY. The proposed Dysinger substation in Royalton was designed to become a transmission hub for Western NY, connecting seven separate 345 kV transmission lines and effectively reducing grid congestion. Additionally, NEETNY included the

23 NYISO, Western New York Public Policy Transmission Planning Final Report, October 17, 2017, p. 38.

development of a new 20-mile transmission line connecting the two new substations in their project proposal.

iii. Project Cost & Timeline

According to the Western New York Public Policy Transmission Planning Report, the cost of the Empire State Line was estimated at $181M.[24] Throughout the course of the Western New York solicitation process, there was discussion regarding cost containment provisions and how they would be evaluated/considered by NYISO. According to a response by the NYISO (as reported in NEETNY's comments), "[NYISO] will not consider cost containment in selection of more efficient or cost-effective Public Policy Transmission Project because such consideration is not provided for in its tariffs. OATT Attachment Y Section 31.4.8.2 states that 'Actual project cost recovery, including any issues related to cost recovery and project cost overruns, will be submitted to, and decided by [FERC]. Cost containment mechanisms can provide benefits to customers, but the key here is what the NYISO has repeatedly made clear: that for this solicitation, it will not consider cost containment in its evaluation process. However, there is nothing to stop any developer from proposing a cost containment mechanism in its FERC formula rate filing.' "[25]

In its formula rate proceeding, NEETNY committed to cap certain costs at $110.4M[26] as part of a Settlement Proceeding, defined as the sum of the following: (A) the Capital Cost Bid, defined as the amount submitted by NEETNY in response to the NYISO's solicitation on the Western New York Public Policy Transmission Need, but excluding Empire Third Party Costs; (B) contingency of 18% will be applied to the Capital Cost Bid; (C) the sum of the Capital Cost Bid and the contingency of 18%, multiplied by an inflation factor of 2.0% per year for the period of time from the submission in response to the NYISO's Solicitation to the date that is one year prior to the Commercial Operation Date; and (D) Allowance for Funds Used During Construction ("AFUDC").

Project construction began in March of 2021, and NEETNY adhered to all scheduling requirements as required by the NYISO. The line entered service on July 12, 2022, against an estimated in-service date of June 2022.[27] Despite remaining largely on schedule, NextEra encountered significant cost

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24 Western New York Public Policy Transmission Planning Report, October 17, 2017, p. 38.

25 NEETNY Comments on NYISO's Draft Western New York Public Policy Transmission Planning Report, July 25, 2017, p. 4.

26 FERC Settlement Agreement, ER16-2719-000, and NextEra Energy Transmission New York, Inc., "2021 & 2022 Formula Rate Annual Projection Response to the New York Transmission Owners' Questions Provided on 12/1/2021" January 10, 2022, p. 3. Empire Third Party Costs are not detailed in the NYISO Selection Report, therefore Concentric assumes the cost cap as reported by NEETNY in its response to the New York Transmission Owners.

27 https://www.nyiso.com/documents/20142/1410651/WNY Presentation.pdf/19586e89-93a8-eb79-5008-b1ae758ae993

overruns, describing "unforeseeable costs" of approximately $74M above the cost cap which NEETNY claims were excluded from the project cost containment mechanism.[28] When all costs are considered, including those that were not part of the cost cap, NEETNY forecasts its 2022 end of year transmission plant in service as $219M. Including intangible plant and general plant, NEETNY's 2022 end of year plant in service is forecasted as $249M.[29]

iv. Challenges

According to documentation regarding the construction of the Empire State Line, NEETNY encountered cost overruns in the categories of regulatory delays, transmission line re-routing and tree clearing, wetland mitigation, and other environmental challenges.[30] This led to cost escalations of approximately $74M above the cost cap, for which NEETNY is seeking full recovery for this cost due to exceptions in its cost cap. This represents a 67% cost increase above NEETNY's project cost cap of $110.4M. The total projected EOY plant in service estimates of $249M represents a 38% increase above the solicitation cost estimate of $181M.[31]

This cost increase offers a striking real-world counterexample to claims of cost savings from proponents of Order No. 1000 competition. Given the scale of this cost increase, policymakers should consider whether competitive processes result in realistic bids, or whether non-incumbent entities may simply seek to underbid the competition while relying on cost cap exceptions to ensure full recovery of actual costs down the road. Further, this example raises legitimate questions about whether these cost escalation factors would have been reasonably foreseeable by an entity with local knowledge and experience with the challenges to transmission development in this jurisdiction.

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28 NextEra Energy Transmission New York, Inc., "2021 & 2022 Formula Rate Annual Projection Response to the New York Transmission Owners' Questions Provided on 12/1/2021" January 10, 2022, p. 1.

29 NEET New York's 2021 and 2022 formula rate revenue requirement projections, March 21, 2022.

30 NextEra Energy Transmission New York, Inc., "2021 & 2022 Formula Rate Annual Projection Response to the New York Transmission Owners' Questions Provided on 12/1/2021" January 10, 2022, p. 1.

31 In general, publicly available information about final costs is not always readily available or transparent, and is often released on a delayed-basis. These figures are derived from public information that was available at the time of this report.

EMPIRE STATE LINE

Final Cost: $249 million

Increase over Initial Cost Cap: 67%

Total increase over Initial Bid Estimate: 38%

Though relatively on schedule, Next Era encountered significant cost overruns, describing "unforeseeable costs" of approximately $74M, which were excluded from the cost containment mechanism and contributed to 38% increase in total project costs.[1]

B. ARTIFICIAL ISLAND

i. Project Overview

PJM identified system performance and voltage issues in the "Artificial Island" area surrounding the Hope Creek and Salem nuclear units in New Jersey during its 2012 and 2013 transmission planning cycle. The transmission stability issue recognized in 2012 led PJM to open a two-month competitive solicitation window on April 29, 2013. After major scoping changes and schedule delays discussed below, LS Power was ultimately selected to construct a 3-mile-long transmission line beneath the surface of the Delaware River to a new substation in Delaware (responsible for construction of both line and substation).

ii. Competitive Solicitation & Schedule

On April 29, 2013, PJM issued a problem statement and opened a 60-day proposal window to address the Artificial Island issues. Seven discrete developers submitted 26 separate proposals with cost estimates ranging from approximately $100M to $1.55 billion for a wide array of projects including, but not limited to, greenfield transmission lines, new substations, system reconfigurations, and dynamic reactive devices.[32] PJM conducted a solicitation and awarded a winner. However, PJM underestimated the cost of integration work at the terminus PSE&G substation. PJM's revised estimates raised the estimated total cost,[33] and this cost increase, in part, led the PJM Board to

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32 PJM Interconnection, Artificial Island White Paper, July 29, 2015, p. 11.

33 PJM, Transmission Expansion Advisory Committee Artificial Island Recommendations to the PJM Board, PJM Staff White Paper, April 5, 2017, p. 4.

suspend the project in August 2016 and direct PJM staff to conduct a more comprehensive analysis. During the reevaluation, PJM staff eliminated certain project elements (including the construction of a Static VAR Compensation device) to lower costs, amended its RFP to reflect the elimination of these project elements and changed the terminus point of the new line from the Salem Substation to the Hope Creek Substation.[34] On April 6, 2017 the PJM Board lifted the suspension on the Artificial Island project and approved PJM staff's recommendation to retain LS Power as the developer of the revised Artificial Island 230 kV transmission line under the revised project scope and route.[35] The LS Power project that was ultimately awarded was substantially different from both the PSE&G project that was initially recommended by PJM Staff in 2014 and the PJM Board-approved project in 2015 that was awarded to LS Power.

iii. Cost

The major components of the Artificial Island project, including LS Power's 230 kV submarine transmission line across the Delaware River entered service in 2020 ("Silver Run"), while final upgrades on the Hope Creek Substation were completed in the spring of 2021.[36] LS Power reported total project costs of $149.5M. This total reflects an end of year transmission rate base total of $156.1M for its portion of Artificial Island, less exclusions and other costs. It also reported an adjusted construction cost cap of $166.3M according to the terms of its Designated Entity Agreement, with approximately $20M of escalation allowed above the $146M baseline cost cap estimate.[37,38]

iv. Challenges

The Artificial Island competitive solicitation process exemplifies many of the ways that competitive solicitations can slow down and otherwise complicate the development of transmission infrastructure. Nearly eight years elapsed between the time that PJM identified the need (2013) and the Silver Run Line entered service (2020). The competitive process itself was extremely lengthy (four years, 2013-2017), with PJM changing the scope and the award of the RFP in the process.

Perhaps more importantly, Silver Run has had performance issues since entering service in 2020. On June 10, 2021, the line tripped due to a submarine cable failure. The line was returned to service on

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34 PJM Press Release, PJM Board Lifts Suspension of Artificial Island, April 6, 2017.
35 PJM Board letter to PJM Stakeholders, April 6, 2017. This letter also noted the cost allocation issues associated with the project.
36 PJM Inside Lines, Artificial Island Project Nears Completion, April 2, 2021.
37 Silver Run Electric LLC, 2021 Annual Updated True-Up, Attachment 4 Rate Base; WP4 – Cost Commitment, July 1, 2022.
38 Silver Run Electric LLC Designated Entity Agreement, Schedule E, Section 1.2(b) & 1.2(d).

June 18, 2021 with reduced ratings, with PJM noting that LS Power plans to repair the damaged cable during a scheduled outage in the fall of 2022. On April 27, 2022, the line was rerated to near-original, though somewhat reduced, capacities. PJM again noted that LS Power still plans to repair the damaged cable during a scheduled outage in the fall of 2022, after which it is projected to return to its original ratings.[39]

ARTIFICIAL ISLAND – SILVER RUN

Final Cost: $149.5M

Increase over Cost Cap: $0

Cost cap escalation provisions allow for nearly $20M of escalation above original cost cap estimate

The Artificial Island competitive solicitation process was arduous, highlighting shortcomings with PJM's competitive bidding process. The Silver Run line entered service in 2020 but soon thereafter tripped offline and has undergone significant derates for much of 2021 and 2022.

C. Duff Coleman

i. Project Overview

The Duff-Coleman Project is a new single circuit 345 kV transmission line between the existing Duff substation, located in southern Indiana, and the existing Coleman substation located in northern Kentucky. The project is expected to span between 30 and 35 miles within Dubois County, Indiana, Spencer County Indiana, and Hancock County, Kentucky.

The Duff-Coleman Project was approved by the MISO Board of Directors in December 2015 as a Market Efficiency Project ("MEP") in its 2015 MISO Transmission Expansion Plan ("MTEP"). MISO determined that the project was needed to strengthen the 345 kV backbone in the MISO Central Region and would provide more than $1 billion in estimated benefits to the region. As part of MISO's

39 PJM Special Notes, April 27, 2022, and January 11, 2022. https://www.pjm.com/markets-and-operations/etools/oasis/special-notices

planning process, MISO performs an extensive congestion study that identifies areas with need for congestion relief and projects that can best provide relief. A project providing congestion relief is approved as a MEP if it: a) has a benefit to cost ratio of at least 1.25; b) has an estimated cost of greater than $5M; and c) has a voltage of 345 kV or higher for more than 50% of the estimated project on a cost basis. MISO estimated that the Duff-Coleman Project would have a total cost of $67M, consisting of $59 M for the competitive portion of the 345 kV transmission line, $5M for upgrades at the Coleman EHV substation, and $3M for upgrades at the Duff substation.[40] The analysis completed in MTEP 15 found that the project would provide significant economic benefits with a benefit to cost ratio of 16.1 to 1, far exceeding the 1.25 to 1 benefit to cost ratio required for designation of a 345 kV transmission project as a Market Efficiency Project.[41]

ii. Competitive Solicitation

In January 2016, MISO initiated its first competitive solicitation process, issuing an RFP for the 345 kV transmission line spanning 31 miles across two states. A total of 11 proposals for the Duff Coleman Project were submitted to MISO from 11 discrete developers. Project proposals were subject to MISO's four evaluation criteria, including: i) cost and design; ii) project implementation; iii) operation and maintenance; and iv) transmission planning participation. Following an extensive review of all applications, MISO ultimately selected Republic Transmission, LLC ("Republic Transmission"), a joint venture between LS Power and Hoosier Energy, and Big Rivers Electric Corporation ("Big Rivers") to construct and own the project.

iii. Costs & Timeline

Republic Transmission was chosen by MISO to build the Duff Coleman transmission line with a bid of $49.8M against a MISO estimated project cost of $58.9M.[42] As noted in the MISO Selection Report, Republic Transmission included a number of rate concessions in its proposal. Among those concessions were: (i) a Total Rate Base Cap of $58.1M; (ii) a Return on Equity ("ROE") cap at the lesser of 9.80% inclusive of incentives or the MISO region-wide base ROE plus an RTO participation adder; (iii) a Schedule Guarantee under which the ROE would be reduced if the Schedule Guarantee was not met; and (iv) an Equity Percentage Cap of 45%.[43,44] On June 28, 2017, MISO and Republic

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40 The substation work was non-competitive and assigned to the incumbent TOs.
41 MISO, Duff-Coleman EHV 345 kV Competitive Transmission Project Selection Report, December 20, 2016, p. 12.
42 MISO Duff-Coleman Selection Report, December 20, 2016, p. 38.
43 MISO Duff-Coleman Selection Report, December 20, 2016, p. 3.
44 MISO, Duff-Coleman Selection Report, December 20, 2016, p. 5.

executed the Amended and Restated Selected Developer Agreement ("SDA") incorporating the rate concessions. Republic Transmission placed the project into service on June 11, 2020, approximately six months before MISO's deadline of January 1, 2021.

iv. Challenges

The Duff-Coleman project faced no significant construction challenges. It is important to note that there is no requirement in either Indiana or Kentucky, the states through which this project was constructed to obtain a Certificate of Need or Route Permit before beginning construction. This drastically simplifies the construction process and reduces the risk of project delays. In addition, according to the MISO records, there were changes to the contractors used for land acquisition services and construction services. Further, the point of interconnection at both the Duff and Coleman substations changed.[45] Neither of these changes resulted in a delay in schedule.

Regarding project cost, Republic provided an updated cost estimate of $54.2M when the project was placed in service in 2020,[46] with the final costs coming in close to the highest project bid of $55.7M.[47] While the final cost estimate did not exceed Republic's rate base cap, this updated cost is closer to MISO's initial planning level estimate. Republic's final cost of $54.2M is also notably greater than the $48.8M median cost estimate value among all bidders before accounting for inflation. This raises questions about whether any benefit was derived from the competitive solicitation, or whether Republic simply delivered a final project cost comparable to what would have been delivered by an incumbent transmission owner.

45 MISO Change Order Log and Current Appendix A, p. 1.

46 MISO, Duff-Coleman Quarterly Status Report, June 11, 2020 expenditures to-date.

47 Big Rivers Electric Corporation acquired the portion of the Duff-Coleman project located in Kentucky and will recover any incremental additional costs from ratepayers.

Table 6: DUFF-COLEMAN PROPOSED COST ESTIMATES[48]

Proposal ID	Cost Estimate
Median	48.8
101	48.8
102	55.7
103	48.0
104	35.2
105	34.0
106	40.0
107	53.7
108	43.3
109	53.8
110	49.8
111	49.6

DUFF COLEMAN

Final Cost: $54.2M

Percentage Above the Median Bid: 11%

There is no requirement in either Indiana or Kentucky, the states through which this project was constructed, to obtain a Certificate of Need or Route Permit before beginning construction. This drastically simplifies the construction process, reduces the risk of project delays, and mitigates the risk of cost overruns. Republic's final cost estimate was above the median bid estimate (before accounting for inflation), indicating little benefit from the solicitation.

D. DELANEY TO COLORADO RIVER– "TEN WEST LINK PROJECT"

i. Project Overview

During the 2013-14 Transmission Planning cycle, CAISO determined an "economically-driven" need for the Delaney-Colorado River Transmission Project to complement reinforcements needed to address the retirement of the SONGS nuclear plant. The Delaney-Colorado River Transmission

48 MISO, Duff-Coleman EHV 345 kV Competitive Transmission Project Selection Report, December 20, 2016.

Project entailed building an approximate 125-mile 500kV line between the Delaney substation and the existing Colorado River substation and would complete a second contiguous circuit from the Palo Verde to Devers substations. The project offered immediate economic and capacity benefits, as well as incremental import capacity benefits of 200 to 300 MW from Arizona, which would be used to support area deliverability issues and ultimately complement more significant transmission reinforcements being considered at the time to support higher levels of renewable generation in development.

ii. Competitive Solicitation

To find a cost-efficient and high-quality solution for the Delaney-Colorado River Transmission Project, the CAISO began a competitive solicitation process in 2014. The bid solicitation period ran for 90 days, from August 19, 2014, to November 19, 2014.[49] Upon closing the three-month-long application window on November 19, 2014, CAISO had received five proposals from five discrete developers in the region. DCR Transmission, LLC ("DCR Transmission"), a joint venture between Starwood Energy Group Global, Inc. and Atlantica Yield PLC, was ultimately chosen by CAISO to lead the Ten West Link Project along with partner Abengoa Transmission and Infrastructure ("ATI").

iii. Costs & Timeline

The Ten West Link Project was estimated to cost $300M.[50] According to the Certificate of Public Convenience and Necessity ("CPCN") filing Order by the California Public Utilities Commission ("CPUC") for Ten West Link Project, the Approved Project Sponsor Agreement ("APSA") between DCR Transmission and CAISO established a cost cap of $241,805,391.[51] Updated project cost estimates from 2016 were $279,560,483, representing overruns of the cost cap previously agreed upon in the 2015 APSA. [52,53]

Due to several challenges, including a route change and a change in in-serve date, the November 2021 CPCN noted a $389M estimate for the Ten West Link Project, over $148M above the cost cap and previous project cost estimates.[54] According documentation in the CPCN proceeding, the Bureau of

49 CAISO, Delaney to Colorado River Project Sponsor Selection Report, July 10, 2015, p. 2.
50 Delaney Colorado River Transmission Line Project, Project Sponsor Selection Report, July 10, 2015, pg. 2.
51 CPUC, Decision Granting DCR Transmission, LLC a CPCN for the Ten West Link Project, November 4, 2021, at p. 64.
52 CAISO, Delaney to Colorado River 500 kV Transmission Line Project Description, Key Selection Factors, and Functional Specifications for Competitive Solicitation, July 2014, p. 2.
53 DCR Transmission, Application for a Certificate of Public Convenience and Necessity for Ten West Link Project, Application A.1610-012, October 12, 2016, p. 12.
54 CPUC, Decision Granting DCR Transmission, LLC a CPCN for the Ten West Link Project, November 4, 2021, at p. 65.

Land Management ("BLM") routinely extended the anticipated dates for completion of the draft Environmental Impact Statement ("EIS") and final EIS for a variety of reasons including a federal furlough and the need for additional information from the applicant. The cost cap was increased to reflect the updated cost estimate, subject to review by the CPUC of actual costs incurred to ensure reasonableness and prudency and to challenge them as appropriate at the FERC proceedings.

iv. Challenges

When CAISO began the competitive solicitation process for the Ten West Link project, the new transmission line spanning from California to Arizona was expected to be in-service no later than May 1, 2020. Yet, through a route change and delays to construction caused by regulatory delays and investigation of alternative line routes, the Ten West Link Project has still not entered commercial operation, although it recently received approval to begin construction.[55] According to DCR Transmission in an Application for a Certificate of Environmental Compatibility, the project underwent a total of four years assessing community outreach, environmental impact, and engineering design when examining an alternative route proposed by the BLM.[56] Updated in-service estimates show that the Ten West Link Project is expected to be in-service by 2023.[57] With detailed knowledge of local regulatory processes and challenges, an incumbent TO might have been positioned to anticipate regulatory challenges and other complications that led to delays.

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55 CPUC, Decision Granting DCR Transmission, LLC a CPCN for the Ten West Link Project, November 4, 2021.

56 DCR Transmission, Application for a Certificate of Environmental Compatibility for the Ten West Link Project, December 9, 2019, p. 4.

57 Starwood Energy Group, Ten West Link Transmission Line receives CPUC Approval, November 8, 2021.

DELANEY TO COLORADO RIVER - TEN WEST LINK

Final Estimated Cost: $389M

Original Cost Cap Exceedance to-date: 61%

This project was expected to be in-service no later than May 1, 2020. Through a route change and delays to construction caused by regulatory delays and investigation of alternative line routes, the Ten West Link Project has not yet entered commercial operation and has exceeded its original cost cap.

E. SUNCREST

i. Project Overview

In 2014, the CAISO recognized a policy-based need for dynamic reactive power support linked to the Suncrest 230 kV bus to support the state's Renewable Portfolio Standard. The CAISO determined that the retirement of the SONGS nuclear facility and projected increases in renewable generating capacity in the Imperial Valley would cause loading and voltage stability issues in the transmission system in the area of the existing Suncrest Substation.

The proposed project included two primary components: (1) an SVC facility, to be located approximately one mile east of the existing Suncrest Substation, and (2) a 230kV transmission line from the proposed SVC facility to the existing substation. The proposed SVC facility would produce and consume reactive power and would interconnect with Suncrest Substation via the approximately one-mile-long 230kV transmission line. The 230kV transmission line would be installed primarily underground, beneath an existing private road, with the last approximately 300 feet of the transmission line transitioning above-ground via a riser pole and an intermediate pole to connect with the existing substation. The proposed SVC facility would be approximately 6 acres in total size and would be located on an area previously used as a construction staging and materials storage area during construction of Suncrest Substation (completed in 2012).

ii. Competitive Solicitation

A project bid solicitation window was opened for two months in the spring of 2014. The CAISO received two proposals for the Suncrest project, one from Horizon West Transmission, LLC ("Horizon West"[58]) and one from San Diego Gas & Electric ("SDG&E"), the incumbent substation owner.[59] Horizon West was formerly known as NextEra Energy Transmission West, LLC ("NEET West"), as seen in documentation from earlier stages of the project.

The CAISO described both entities as highly qualified with viable solutions, leading to a lengthy comparative analysis to determine selection. SDG&E did not require a CPCN for the Suncrest Project, whereas Horizon West did. The CAISO evaluated the bids and selected Horizon West as the winning project sponsor, primarily due to Horizon West's cost proposal, which included a binding construction cap and robust cost containment measures limiting the amount for which Horizon West would seek cost recovery. Horizon West, still under the name of NEET West at the time, signed an Approved Project Sponsor Agreement with CAISO on May 7, 2015.[60]

iii. Cost & Timeline

The Suncrest Project began construction in early 2019. The construction process was estimated to take approximately a year. The Suncrest Project entered service in 2020. Assuming 2% per annum inflation escalation on the 2015 cost cap, 2021 net transmission plant costs exceeded the inflation-adjusted cost cap by approximately 14%.

Horizon West offered a project construction cost cap of $42,288,000, with operation and maintenance costs for the first five years of operation capped at $360,000 per year.

CAISO provided an initial cost estimate range of $50-75M for the Suncrest Project, as stated in the 2014 Sponsor Selection Report.[61] Once Suncrest entered service in 2020, final transmission plant in service for the project were determined to be roughly $48M per its 2020 formula rate filing, falling slightly below the initial CAISO-estimated range.[62] Horizon West's 2021 FERC formula rate filing showed a transmission plant in service of $53M, within CAISO's initial estimated cost estimate

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58 NextEra Energy Transmission West, LLC, , or NEET West, changed its name to Horizon West Transmission, LLC.

59 CAISO, Key Selection Factors in Selection of Successful Project Sponsors Relating to the 2013-2014 Transmission Plan, May 1, 2014, p. 2.

60 NEET West Certificate of Public Convenience and Necessity for the Suncrest Dynamic Reactive Power Support Project, Application A.15-08-027, Exhibit NEET West-10, filed August 31, 2015, Approved Project Sponsor Agreement-Appendix E, p. 43.

61 CAISO, Suncrest 230 kV 300 MVAr Dynamic Reactive Power Support Description and Functional Specifications for Competitive Solicitation, April 15, 2014, p. 2.

62 Horizon West Transmission, Annual Actual 2020, Attachment 2, Line 5.

range.[63] The 2021 formula rate filing also recorded an unamortized regulatory asset of $14M in rate base.[64]

iv. Challenges

CAISO awarded the Suncrest Project to Horizon West in January of 2015 and established a required in-service date for Suncrest to be no later than June 1, 2017. However, the CPUC did not issue a CPCN until October 2018, after citing numerous deficiencies in the initial Horizon West application and issuing a Deficiency Letter.[65] Thus, the project did not begin construction until early 2019, and entered service in 2020, three years later than CAISO's deadline.

SUNCREST

Final Cost: $53M

Cost Cap Exceedance: 14%

This project was awarded in January of 2015 with a required in-service date of June 2017. The project did not enter service until 2020 and exceeded its cost cap by 14%.

F. Harry Allen to Eldorado

i. Project Overview

During 2013-14 transmission planning, CAISO identified an "economically-driven" need for a new 500 kV transmission line between Southern California Edison's ("SCE") 500 kV Harry Allen and NV Energy's Eldorado Substations and opened a three-month bid solicitation window on January 30, 2015, running through April 15, 2015. The 60-mile-long transmission line begins just south of Las Vegas, crossing through eastern suburbs and ending in the desert terrain to the north of the city.[66]

ii. Competitive Solicitation

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63 Horizon West Transmission, Annual Actual 2021, Attachment 2, Line 15.

64 Horizon West Transmission, Annual Actual 2021, Appendix III, p. 1.

65 CPUC, Completeness Review of NextEra Energy Transmission West, LLC (NextEra) Application (A.15-08-027) and Proponent's Environmental Assessment (PEA) for the Suncrest Dynamic Reactive Power Support Project (Proposed Project), letter dated October 1, 2015.

66 CAISO, Harry Allen-Eldorado 500 kV Transmission Line Project Sponsor Selection Report, January 11, 2016, pp. 2, 10.

During the solicitation window, CAISO received proposals from a total of three discrete developers. Following an extensive review of each sponsor's application, CAISO selected Desert Link, a subsidiary of LS Power, over Exelon Transmission and NextEra.

iii. Cost & Timeline

CAISO estimated final project costs for the Harry Allen to Eldorado transmission line of approximately $144M in the Project Sponsor Selection Report.[67] According to an October 2017 formula rate filing with FERC (Docket No. ER17-135-000, et al.), DesertLink and CAISO executed an APSA on June 20, 2016. DesertLink agreed in the APSA with CAISO to limit recovery of capital costs to $147M for the project, subject to certain conditions and exceptions. Pursuant to a settlement FERC certified in May 2018,[68] DesertLink maintained a plan from their 2016 project proposal to limit equity as a percentage of its capital structure to 50% and to limit the return on equity ("ROE") included in its annual transmission revenue requirement ("ATRR") to 9.8% inclusive of a 50 basis point adder for CAISO membership.[69,70] Desert Link also agreed in the settlement that the transmission line would be in service by May 1, 2020, and that the transmission revenue requirement cost cap used in winning the competitive bid ($147M) would be adhered to.

Despite the application of a cost cap for the Harry Allen to Eldorado transmission line, DesertLink indicated a final cost of $202.4M for the project. Cost exclusions of $57.7M are behind this overrun in spending; Desert Link explained costs related to "Gross Plant in Service" and "Unamortized Regulatory Asset" were responsible for the developer exceeding estimates.[71] These costs are allowed to be recovered by DesertLink in their revenue requirement.

iv. Challenges

DesertLink remained on schedule for the majority of the project, yet CAISO's in-service deadline of May 1, 2020, was not met; the line entered service on August 12, 2020. The project cost, not including excluded costs, was $144.7M as compared to a cost cap of $147M. However, excluded costs were quite significant, as has been seen across a number of the competitive solicitations. In this case,

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67 CAISO, Harry Allen-Eldorado Project Sponsor Selection Report, January 11, 2016, p. 2.
68 *Desert Link, LLC*, Certification of Uncontested Settlement, 163 FERC ¶ 63,014 (May 24, 2018).
69 CAISO, Harry Allen-Eldorado 500 kV Transmission Line Project Sponsor Selection Report, January 11, 2016, pp. 2, 73, 74.
70 *Desert Link, LLC*, Certification of Uncontested Settlement, 163 FERC ¶ 63,014 (May 24, 2018), p. 5.
71 DesertLink, DesertLink Rate Year 2020 Annual Update, July 1, 2021.

excluded costs totaled $57.6M, or 39% of the binding cost cap. DesertLink is seeking cost recovery of and on the total project cost of $202.4M.

HARRY ALLEN TO ELDORADO

Final Cost: $202.4M

Cost Cap Exceedance: 39%

The excluded costs for this project were significant, totaling $58M or 39% above the binding cost cap.

VI. FINDINGS & CONCLUSIONS

Our review of individual Order 1000 projects reveals that the competitive process has not delivered the benefits to customers that were expected. As the FERC has noted, "the remedy prescribed by Order No. 1000 failed to recognize that at least some of the most notable expected benefits from competitive transmission development processes (e.g., new transmission developer market entry, greater innovation in and potentially lower costs of transmission development) could be achieved or at least reasonably approximated through other means."[72] It is not evident that lower costs and greater innovation have been realized on a broad scale through the implementation of Order 1000. In fact, project selection criteria that emphasize low costs may run counter to the goals of innovation via new solutions.

As noted previously, competitively bid projects have seen a range of successes and challenges in terms of schedule adherence. The Delaney to Colorado River Project has experienced significant schedule adherence challenges via a major route change and other construction delays. Related challenges arose for Suncrest; despite the need having been identified in 2014, the CPUC did not approve the decision for the project until October 2018, and the project did not enter service until 2020, three years later than CAISO's deadline. Additionally, one of the most significant expenditures was time. Time is an important consideration because delayed project development denies customers the benefits of transmission investments, such as reduced congestion costs or increased reliability. The time, money and resources these solicitations require should not be overlooked because delays in awarding projects and ISO/RTO costs and resource burdens lessen any benefits otherwise realized by customers. For each solicitation examined, Table 7 shows the time between the date the project need was first identified, final ISO/RTO Board approval of the winning bidder, and the year the project entered or is expected to enter service. The time between identification and award date is significant, with the shortest timeframe being approximately 9.5 months (Suncrest). The shortest time frame between when a need was identified and a project's in-service date was approximately four and a half years (Duff Coleman). Incumbents and non-incumbents alike can be subject to project delays for various reasons, however the time added by the Order No. 1000 competitive process is a cost to customers in either case.

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72 FERC ANOPR, Docket No. RM21-17-000, April 21, 2022, p. 277-78.

Table 7: CASE STUDY SOLICITATION TIMELINES

NAME	ISO/RTO	NEED IDENTIFIED DATE	SOLICITATION AWARDED DATE	DAYS BETWEEN NEED IDENTIFICATION AND SELECTION	IN SERVICE DATE	ISO REQUIRED IN-SERVICE DATE
Empire State	NYISO	7/20/2015	10/17/2017	820	July 2022	June 2022
Artificial Island	PJM	Fall 2012	7/29/2015	950+	May 2020	April 2019 [73]
Suncrest	CAISO	3/25/2014	1/6/2015	287	Feb. 2020	June 2017
Delaney to Colorado	CAISO	7/15/2014	7/10/2015	360	2023	May 2020
Duff Coleman	MISO	12/1/2015	12/20/2016	385	June 2020	Jan. 2021
Harry Allen to Eldorado	CAISO	7/16/2014	1/11/2016	544	Aug. 2020	May 2020

In terms of the efficiency of the Order 1000 solicitation process and removing the ROFR to make way for non-incumbent developers, there remain a limited number of developers active in the competitive transmission space. This is likely due to the fact that owners and operators of transmission infrastructure must possess important and specific levels of expertise, be able to attract capital, manage risk, and make long-term operating commitments. Bidders incur significant costs to prepare bids and participate in competitive solicitations, as do RTO/ISOs to manage those solicitations. New entrants must also be able to stay the course to ensure the long-term reliability of the infrastructure being developed. The stated objective of encouraging new developer market entry does not appear to have been achieved. The number of developers participating in each of the solicitations examined have remained relatively constant, and the number of discrete winning bidders has been limited.

73 PJM's initial in-service date was April 2019. Due to challenges throughout the process that are discussed in Section V, the project was suspended and rescoped. PJM's updated in-service date was June 2020. Silver Run Electric entered commercial operation on-time. We note the delays associated with the Artificial Island process overall.

Table 8: CASE STUDY SOLICITATION SUMMARY

NAME	ISO/RTO	SOLICITATION AWARDED DATE	#BIDDERS	AVERAGE BID ($M)
Empire State	NYISO	10/17/2017	7	265
Artificial Island	PJM	7/29/2015	11	780
Suncrest	CAISO	1/6/2015	2	NA
Delaney to Colorado	CAISO	7/10/2015	5	NA
Duff Coleman	MISO	12/20/2016	11	53
Harry Allen to Eldorado	CAISO	1/11/2016	3	NA

Building transmission infrastructure, particularly large greenfield projects, involves a dynamic set of technical, economic, and regulatory assumptions that affect schedule and cost. Transmission developers review and report cost estimates throughout the project development cycle and the precision of these cost estimates differs by stage and increases as the project progresses from the conceptual stage to the design, engineering, and construction stages. Cost uncertainties are typically beyond the developer's control – regardless of whether or not the developer is a non-incumbent. Given these uncertainties, transmission project developers frequently include contingencies or exclusions in their capped costs or cost guarantees. Proponents of competition have tended to ignore this aspect of bids by highlighting the initial bid estimates for selected projects. However, there is now concrete evidence that exceptions to cost caps have been used to pass through cost increases to customers, while allowing the bidder to claim a "low" cost in order to win the project.

The projects examined do in fact reveal cost overruns in the categories of regulatory delays, transmission line re-routing, wetland mitigation, and other environmental challenges. Harry Allen to El Dorado (DesertLink) and Empire State lines are two that experienced the most significant cost overruns of approximately 38%.

Not all projects will exceed their cost caps, as evidenced by the Duff Coleman example. However, the Duff-Coleman project costs are roughly equal to the average of other submitted bids. This raises questions about whether the competitive process, even when it does not result in cost escalations above caps, results in any actual cost savings for customers. This question should also be considered in the context of the broader direct and indirect costs of competition, and the delays imposed by the process.

It is important to note however that a simplistic and narrow focus on whether solicitations result in cost savings ignores the broader and important considerations of benefits associated with historical models of transmission ownership and management of transmission systems. These benefits represent possible opportunity costs of competitive solicitations in terms of the foregone benefit of time and resources devoted to the myriad of issues facing the industry, which must be considered in addition to the direct costs, benefits, and uncertainties of the solicitations held to-date.

The following provides a high-level summary of anticipated costs versus final project costs.

Table 9: CASE STUDY COST SUMMARY

NAME	REGION	REGION'S COST ESTIMATE ($M) *	WINNING BID COST ESTIMATE ($M)	FINAL COST OR CURRENT ESTIMATE ($M)
Empire State	NYISO	NA	181	249
Artificial Island	PJM	NA	146	149.5
Duff Coleman	MISO	58.9	49.8	54.2
Delaney to Colorado	CAISO	325[74]	300	389
Suncrest	CAISO	50-75	42.3	53
Harry Allen to Eldorado	CAISO	120[75]	144	202.4

Based on the case studies reviewed in this paper, Order No. 1000 competitive solicitations have not delivered innovation, cost savings, or timely development of transmission. As FERC considers reforms to its transmission planning and cost allocation policies, it is important to consider the real results of competitive processes to-date, compared against claims of significant cost savings. In short, the experience to-date with real projects contradicts these arguments.[76] The timely development of transmission is critical for meeting clean energy goals and capturing significant economic benefits for customers, and results to-date indicate that the Order No. 1000 competitive framework may be a hindrance to these goals and does not appear to provide particular value in advancing them.

74 CAISO, 2013-2014 Transmission Plan, July 16, 2014, p. 266.
75 CAISO, 2013-2014 Transmission Plan, July 16, 2014, p. 252.
76 Additionally, full operational experience with competitively-developed facilities is not yet known, however more information will be revealed over time as operational experience grows and the effective maintenance of these facilities can be more easily measured.