Building New Critical Infrastructure: No Time to Waste

Evaluating Cost Transparency Between a Federal Right of First Refusal and Competitive Bidding in Electrical Transmission Infrastructure Expansion

ALLIANCE FOR INNOVATION AND INFRASTRUCTURE

July 2024

Executive Summary

The energy grid must expand to meet the current and future needs of the country. The projected expansion will require substantial increase in the capacity and scale of high-voltage transmission infrastructure. Building this type of transmission infrastructure has, in many cases, taken a decade or more and come with a considerable price tag, one that is ultimately passed to ratepayers. This brings costs and time to the forefront of the infrastructure expansion discussion.

In recent years, both state and federal lawmakers and regulators have sought to reform transmission policy and clarify planning and cost allocation to ensure needed projects get built. The Federal Energy Regulatory Commission (FERC) instituted a major set of reforms in 2011 that, among other things, eliminated the federal Right of First Refusal (ROFR), which gave existing transmission utilities priority in developing new regional and interregional transmission projects.

The introduction of competitive bidding for transmission projects produced debate and disagreement as to its effects on development costs and time. With unrealized expectations from the 2011 reform in practice, FERC recently issued a new order to refine the rules for planning and cost allocation. While the latest order touches on ROFR, it does not settle the topic at a national level nor prevent states from adding or removing their own state-level ROFR laws.

The necessary build out of high-voltage transmission infrastructure on a national scale will take deliberate planning and considerable time. The processes used to facilitate that building can add or reduce this time and will ultimately affect the costs, which manifest in at least three ways: construction cost, ratepayer costs, and opportunity costs for unrealized growth while power projects are delayed. Accordingly, the total time it takes to plan, build, and realize a particular project must be factored into the analysis.

This report assesses utility expansion within the context of FERC Order No. 1000 but is not an evaluation of that order. Similarly, while Order No. 1920 subsequently introduced ROFR and other planning reforms, we do not analyze the specific orders. Rather, we review differences in cost transparency between ROFR and competitive bidding in principle and as they manifested in practice as a result of FERC orders.

By surveying the literature on competitive bidding over the past decade, this paper provides an overview of key industry findings and offers policymakers insight into central aspects of the issue. In particular, this paper:

- Highlights the importance of time in the analysis of costs for transmission buildouts.
- Argues that time is not adequately accounted for by most parties and leads to unseen costs, which include direct ratepayer costs and indirect regional economic harm.
- Raises questions about many of the reports purporting to show significant cost savings from competition and notes the results of reports showing the opposite finding by renewing analyses with more updated figures.
- Underscores the importance of efficient transmission buildout to meet future needs.

Introduction

The United States currently consumes around four trillion kilowatt hours of electricity each year.[1] By 2035, this is projected to exceed 4.5 trillion kWh, and by 2050, reach an incredible five trillion kWh.[2] This will require at least a 60 percent expansion of the electrical grid by 2030, with a projected growth of up to 2.5 times in capacity by 2050.[3,4]

Building out the infrastructure to meet these increases in demand while maintaining a reliable and affordable system is truly a monumental task.[5] It will require expansion in multiple energy sectors, including resource development, technological innovation for renewables, transmission infrastructure to move power across long distances, and distribution infrastructure to deliver power to end users directly.

Central to that equation is high-voltage transmission infrastructure. This will need to be built out to increase capacity both in terms of power load and increase linear mileage to connect new and remote energy sources like wind and solar farms. Among the existing challenges are land-use issues and environmental considerations, permitting and regulatory compliance, and the high cost[6] of the physical infrastructure components and construction processes. It can take a decade or more to build regional and interregional high-voltage transmission infrastructure, and in certain circumstances up to 20 years.[7] This brings cost and time into direct focus and placed under a microscope by both industry actors and policymakers. To double the scale of the grid, as experts project, it would take up to 140 years given rate it took to develop transmission lines between 2008 to 2021.[8]

Policymakers have discussed cost allocation as a key element of the overall cost assessment. That deals with which parties pay for the construction and ongoing operation of the transmission infrastructure. It has led to debate between parties believing different processes will lead to different cost outcomes. Within those processes, time will have a determinative impact on cost.

At issue are the requirements introduced through FERC Order No. 1000 aimed at ensuring more efficient and cost-effective transmission processes. The order eliminated a federal ROFR that had given incumbent utilities in a region priority to build new infrastructure and recoup their costs. The introduction of competition removed a barrier to entry for non-incumbent transmission developers and enabled them to submit bids to compete for projects, winning the right to build and collect charges for the transmission project.

The debate over the effects of competitive processes that resulted from Order No. 1000 requirements has continued for many years. Incumbent transmission utilities argue, among other things, a federal ROFR saves time and cost and allows new infrastructure to go into service without undue delay. Non-incumbent or independent transmission developers argue they can save substantial development costs that would ultimately serve ratepayers in the long run.

There are strong voices and perspectives on each side making forceful arguments, which has left policymakers to choose between difficult approaches. This work seeks to survey the literature on the subject and highlight certain aspects. This cannot be done without also underscoring the criticality of innovation to both cost savings and system resilience.

Time as a Lens

The primary focus of this report is to review the existing literature on cost transparency and differences in transmission infrastructure building since FERC Order No. 1000 and to assess the impact and value of time. As we have explored in recent publications, time is a cost in itself, and it is often misunderstood or not adequately accounted for.[9] While most cost-benefit analyses, project plans, and competitive bids factor time into their equation, there is good reason to believe it is underestimated – if not by the developer, then by policymakers viewing multiple and interrelated projects. The reason time is so important is because it represents uncertainty and economic costs.

Time means opportunity. The longer a project is in the planning phase or even the construction phase, the greater number of adverse events can occur that alter and/or delay the initial planned development timeline. Time presents opportunities for changes in underlying demand, project scope, inflation, lawsuits, supply chain disruptions, material sourcing challenges, changes in leadership, contract disputes, political elections, legislative and regulatory changes, weather events, protests, hostile action, mistakes, oversights, pandemics, global conflict, regional instability, and more. In a federal system, where regulatory schema can be duplicated at both state and national level, some of these delays are compounded, such as certain permitting requirements.

Policymakers must develop a nuanced appreciation for time in their decision making and evaluations. Transmission infrastructure is vulnerable to delays associated with a variety of issues, including permitting and siting, supply chain dependency, local or regional market dynamics, environmental considerations, and more. The added time to facilitate competitive solicitations and finalize winning developers must be understood as a cost and weighed in proportion to all other variables. According to a review of the relevant literature and the most recent data, solicitations for transmission projects add over a year on average to the process.[10,11]

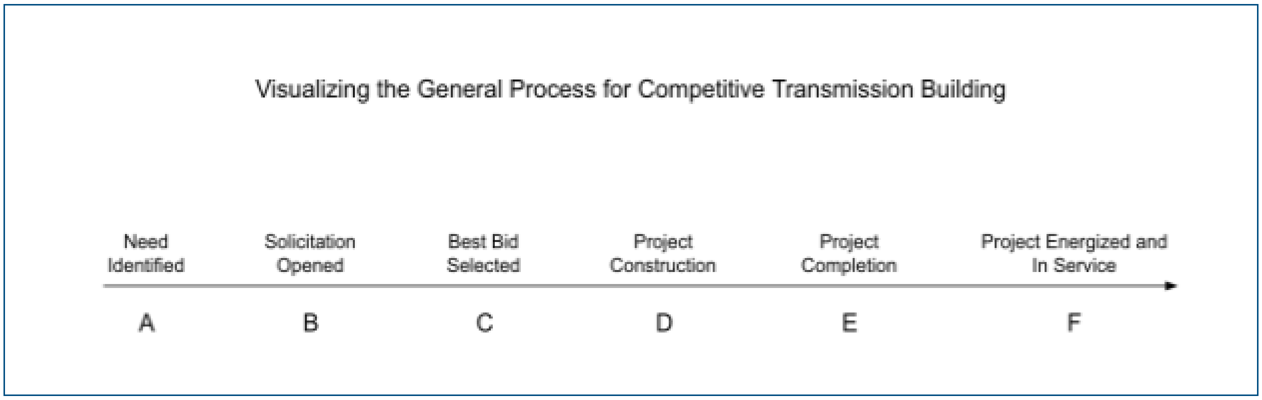
While competitive bids do account for time in many ways, for instance by projecting for inflation or certain adjustments, delays can lead to unexpected and therefore unplanned escalations in cost. Conditions may simply change by the time the bid is won in ways that materially impact elements of the bid and planning. Additionally, certain costs are not always visible in the project itself, such as the price of a winning bid not capturing the cost effects of a year of delay to facilitate the bidding process itself.

> "The added time to facilitate competitive solicitations and finalize winning developers must be understood as a cost and weighed in proportion to all other variables."

Focusing too narrowly on competitive bidding may lead policymakers to only see two cost concepts: the overall project cost and the utility bills ratepayers see. Yet there are costs to the region and the economy of delayed power supply, as investments are not made and gains are not realized while the transmission line is still in the planning or construction phase. Even one year of delay may have a substantial impact on economic activity for those awaiting power.

Perhaps equally critical for policymakers making an educated assessment and decision on this matter is to also look at time a different way: how recent and complete is the data they are using to make decisions. The year a study was conducted and when costs were estimated/captured will have determinative effect. Research citing ongoing projects or estimated costs will necessarily require updates when final or mature numbers are known. More recent reports should be viewed with a presumption of greater reliability due to more final data being available.[12]

To better conceptualize the direct and indirect costs of time and delays in transmission infrastructure building, we can compare certain notable and generalized project stages.



Aii Figure 1: Transmission Project Basic Timeline

The process to solicit bids, evaluate proposed solutions, and select a winner is "complex, expensive, and time consuming"[13] and can take up to a year or more. Permitting and regulatory compliance must also be undertaken by the project developer, who may have existing permits or relationships in a region and may not. Project construction is substantial and complex, starting with site preparation and ending with restoration,[14] and the total process can take a decade for larger projects, during which delays and added costs are common. Once the project is complete, the overall direct financial cost will be known and can be compared to the estimate.

Lastly, the project is energized and power moves through the transmission lines, connecting power generation to distribution networks to serve customers. Only then does the clock fully close on capturing the time cost of the process. Importantly, the known costs here are the final mature project cost to build the transmission lines and the costs ratepayers will see. It may not be possible to know the unrealized gains that were foregone during delays in bringing the power to market.

Historical Context

Prior to 2011, incumbent utilities developed electric transmission within their own service territories. In some regions, they did so under a federal ROFR within FERC-jurisdictional tariffs and agreements. While such rights did not prevent non-incumbent development, they did require that the existing utility opt not to undertake a new transmission facility project selected in a regional transmission plan.

Some have pointed out that there has always been opportunity for competition with the right initiative, but the incentives were not there to sustain or cultivate it, and certain policy itself was part of the equation.

> Prior to Order 1000, there was nothing in principle that kept an independent transmission developer from proposing to an ISO[15] to build a project and to recover its costs from the revenues it anticipates receiving from the sales of congestion revenue rights alone. This is a classical merchant transmission project.[16]

Nevertheless, existing transmission utilities know their transmission systems best and may be best positioned to understand the demand dynamics, the region and its environmental and climate context, and have relationships with suppliers and contractors to most effectively identify and complete expansions.[17]

Over time, and in hopes of promoting more efficient and cost-effective transmission development, FERC elected to eliminate the federal rights of first refusal from jurisdictional tariffs and agreements. In many regions, this ushered in competitive solicitations to bring independent transmission developers into existing transmission planning processes.

When FERC Order No. 1000 was issued in 2011, incumbent transmission utilities argued they could deliver more cost-effective transmission projects because they avoided the added time from a solicitation process, they knew the terrain, and could leverage existing relationships, permits, and other assets to build faster to ultimately keep costs down. Non-incumbent developers argued the success of competition in other industries and contexts would apply in transmission building as well. Some academic journals said that the rule was merely a small step that would not bring significant changes, while others believed it could be a sign of progress.[18,19]

What is not in debate is that Order No. 1000 did not produce the intended results, leading FERC to reconsider its policy and propose new reforms.[20] Prompted by a recognition that requiring the elimination of all federal ROFR for new transmission facilities selected in a regional plan was overly broad, the mixed results in cost savings, and development concentrated in transmission projects not subject to the new rules, FERC revisited the matter and issued Order No. 1920 in May 2024.

The new order included limited ROFR provisions, while currently, at least a dozen states have a state ROFR law or are considering adding, revising, or removing a ROFR law.[21,22] The issue also remains debated at a federal level, ranging from expanding the ROFR policy to preempting state laws altogether.

Literature Review

Incumbent utilities generally support limiting solicitation models in their own service territories, while non-incumbent transmission providers support expansion thereof. Virtually all stakeholders, independent observers, and academic sources all agree that Order No. 1000 did not bring the intended changes, but disagreement remains over the best way to proceed.

Through the process of reviewing the relevant literature, we noted that many reports on time and cost transparency cite back to a handful of quantitative reports. While some others conduct light analysis, they ultimately draw their information from another group. Accordingly, rather than present a literature review on all reports, this section addresses a set of primary sources.

Competitive Market Proponents

Those seeking to increase competition in the transmission building industry focus on the potential to generate cost savings and lower electricity prices for ratepayers, emphasizing the differential between a winning competitive bid and the initial expected cost of a project. Non-incumbent developers are quick to admit that FERC Order No. 1000 did not bring the changes the commission sought, but they maintain that this is because the new rules were not applied to all areas of transmission development and enforcement was lacking.

The cornerstone of the competition in transmission perspective is a 2019 report, *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*," by ***The Brattle Group*** sponsored by ***LSP Transmission Holdings, LLC***.[23] This is one of a number of works on transmission and competition by Brattle analyzing the issue over the years, including reports, presentations, and webinars.[24,25,26,27] The report conducts direct cost comparisons between initial ISO/RTO or incumbent estimates and winning competitive bids to produce purported cost savings metrics.

It also provides general historical cost escalations as a basis of comparison. However, the report findings have largely been invalidated by final project costs. While the Brattle report compares key data points, none of the projects evaluated were complete when the report was issued, and as the report notes in numerous places "cost escalations" do occur throughout the lifespan of a project. In a subsequent report in the same year, Brattle insisted that its report findings were secure, even with certain projects yet uncompleted.[28] This is a continued belief, cited as recently as March 2024.[29]

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The *Cost Savings* report suggests a proposed range of cost savings between 20 percent and 30 percent from competitive project bidding. This is then applied to levels of competition to generate potential ratepayer and economy-wide savings.[30]

The report also notes that "competitive transmission solicitations were priced 15% to 60% (averaging 40%) below either the initial project cost estimate or the lowest-cost incumbent project offer price."[31] This 40 percent statistic (along with the range used to produced it) is highly dependent on one atypical project in which an incumbent revised its bid and produced a lower offer.[32] The Brattle analysis retains the higher number and thus inflates the entire range that sustains the purported 40 percent average savings.[33]

Regardless of the methodology and saving statistic presented in the Brattle report, the projects analyzed in 2019 were not yet completed. The costs for some projects rose after the report was published, undermining the ultimate findings and conclusions. For these reasons, the Brattle Group report serves as an important introduction to the subject but also provides a note of caution. Policymakers should look to more up-to-date reports with final cost calculations to inform future decisions.

Brattle produced one additional report, "Response to Concentric Energy Advisors' Report on Competitive Transmission" also in 2019. In response to costs and project timelines, the Response Report notes that solicitation processes took over a year, but some took around three months. Brattle argued that over time, as solicitations are refined, the time necessary to conduct them will shrink.

The ***Electricity Transmission Competition Coalition (ETCC)*****,** which represents non-incumbent transmission developers and a diverse group of 92 total[34] organizations, released a report in 2023 that is representative of many follow-on reports. With a bold claim as the report title, "FERC's $277 billion electricity price hike," ETCC decries the agency's failure to enforce competition.

The "report & survey" however does not produce original quantitative analysis or economic statistics about FERC's order, transmission building, or competition. Rather it relies on findings from the Brattle Report and applies them to a claim from a different report on projected growth by 2050. The survey results focus largely on consumer preference and perceptions.

To achieve the titular $277 billion figure, the report multiplies 40 percent (purported project savings[35]) by one-third (of all new transmission projects) by $2.1 trillion (purported cost of transmission investment by 2050). [36]The purported transmission investment figure[37] is a projection for expanding the transmission grid capacity by 3.1 times the 2020 level and relying on a 1,156.22 percent increase in installed wind power capacity and a 1,940.82 percent increase in installed utility-scale solar capacity.[38] This scenario leads to a high-end transmission estimate because of the remote locations of these utility-scale energy projects and long-distance transmission needed to connect them to the grid.[39,40]

By selecting an inflated savings rate, an infeasible rate of competition for new projects – many of which are outside of FERC's jurisdiction given state ROFR laws – and an overestimate for transmission buildout costs, the report overstates what is realistic. Likewise, its further claim of $840 billion in ratepayer savings through competition by 2050 is entirely unfounded.[41]

Other stakeholders and literature representing ***non-incumbent transmission developers*** primarily rely on general economic arguments that do not always draw on robust datasets within the transmission building industry. In some, there are also references to international examples, which do not always align with U.S. regulatory and market dynamics in ways that are perfectly applicable, though these often indicate savings associated with competition.

The pro-competition literature focuses on four core concepts: cost savings,[42] general free market principles, legal opposition to monopolies or the constitutionality of ROFR laws, and public perception of the favorability of competition.

ROFR Proponents

The need to build out new transmission infrastructure, increase capacity, and maintain the resilience of the system are of critical importance. This is core to the argument of incumbent utilities, arguing that changes to the process by FERC have undermined the build out both by adding costs and increasing the time to put new projects into service. Without a federal ROFR, the bidding process for new transmission projects can take up to a year or more, a principal argument among incumbent transmission providers.[43]

Incumbent developers seeking a restored federal ROFR have advanced evidence that the elimination of the rule has not brought the changes sought by the FERC, and instead may have increased prices. Given the previous federal ROFR, the following literature tends to be defensive or responsive to the pro-competition literature above. ROFR proponents have also produced new reports with updated data in four of the last six years.

A report from ***Developers Advocating Transmission Advancements*** (***DATA), a coalition of incumbent transmission providers***, challenges the notion that competitive processes have created savings for customers and finds that final costs for many projects *actually increased* relative to winning bid levels.[44] The ***DATA*** paper revisits the 2019 Brattle report, employing its same methodology and projects but updating with the final costs for projects completed after 2019.

Whereas Brattle argued that a competitive bidding process had led to winning bids 20 percent to 30 percent lower than estimates from traditional developers, the ***DATA*** report from 2023 found that exemptions to the cost commitments that winning bidders provided meant that costs actually *increased* six percent over the baseline.[45] With two adjustments, the report claims the true cost of competition is a 12 percent to 19 percent increase over the baseline using an unweighted analysis, while a weighted analysis results in the competitively solicited projects from the Brattle report in 2019 leading to a 24 percent increase over the baseline.

While this report effectively reproduces the model of the 2019 Brattle *Cost Savings* report, to demonstrate that final costs reveal cost escalation over baseline that eliminate savings, the report does not claim that incumbents do not face the risks of cost escalation. A reason given for cost escalations of winning projects is that competitive bidders use artificially low bids to win solicitations but revise project costs during construction, which is permitted by exemptions to many of the cost caps in winning bids. The report notes the importance of time by its use of final or mature cost figures for projects that are only available once the clock closes on a project.

Two previous reports, each sponsored by ***DATA*** and completed by ***Concentric Energy Advisors*** make a positive case for incumbent transmission owners operating outside of solicitations.[46,47]

Hocking Hills State Park, Logan, OH, USA (credit: snake v.)

The DATA reports offer insight by demonstrating that on average the competitive process leads to a delays and increased costs. To argue this, the reports use updated cost estimates rather than baseline initial estimates. While this does account for reasonable and refined project updates, it also moves the estimate forward in time and bakes in some of the cost increases since the initial estimate.[48]

The second report directly links project delays to cost escalations for competitive projects, pointing to "as many as 1,000 days" added to projects.[49] This report also argues that exceptions to cost caps serve as a pass through for costs to consumers, making long timelines and delays problematic because costs continue to accrue and can then be allocated to ratepayers.

The latest report, published in April 2024 by ***Concentric Energy Advisors*** on behalf of ***DATA*** argues that, according to the latest available data, the timing and cost performance of incumbents and non-incumbent developers are statistically similar within the framework of Order No. 1000. Paired with the fact that the competitive process is costly and time-consuming and inherently generates delays, this may suggest that incumbents with a ROFR are more economically advantageous by avoiding the costs and delays of the solicitation process.

However, like all reports examining the effects of Order No. 1000, the data set is extremely small. Just two of the transmission projects from the 2022 report had new data to analyze, and the lack of comparable data on other projects ensured that no definite statistical conclusions could be made. The report takes issue with the cost cap exceptions for competitive projects and the time-consuming bidding process but was unable to prove that competitive projects are more expensive or time-consuming after a bid is selected, only that the cost savings from competition are not demonstrated in the current data.

Other stakeholder reports put emphasis upon the collaborative environment, which has changed significantly since Order No. 1000. A report from ***Grid Strategies,*** a power sector consulting firm and sponsored by ***WIRES,*** a trade association of transmission providers, argues that Order No. 1000 has significantly decreased collaboration by increasing competition.[50] The report argues that collaboration is essential for developing effective transmission infrastructure, but in a more competitive environment there are far fewer incentives for collaboration.

The pro-ROFR literature focuses on the three core concepts: unrealized cost savings from competition,[51] the regional knowledge advantage of incumbents, and the potential delays the solicitation contribute to transmission development.

State of the Literature

Many of the reports arguing both for and against ROFR or any reforms to FERC Order No. 1000 are made by stakeholders with a direct financial interest in the outcome. Incumbents desire a return to regulated monopolies, while non-incumbents want to be able to bid for projects. An overview of the available literature and arguments from a range of perspectives suggests that there are more dimensions to this issue than merely cost competitiveness. Literature emphasizing a right of first refusal focuses on the benefit of faster and more efficient infrastructure build outs. These also argue newcomers may lack specialized knowledge of the region or market necessary to succeed beyond costs. The literature supportive of a competitive bidding process ties the infrastructure markets to bedrock free-market principles demonstrated over time to deliver cost savings and even innovation.

"An overview of the available literature and arguments from a range of perspectives suggests that there are more dimensions to this issue than merely cost competitiveness."

Ultimately, more research is useful to demonstrate the way time and costs manifest together once more projects mature. Existing data adequately serves to show the impact of delays on project costs, but inconsistent terms, assumptions, and project sets used in reports and discussions continue to allow conflicting conclusions by industry and policymakers. Even with a clear line of research with updated figures, the issue is new enough and projects slow enough that sufficient data is still lacking for a meaningful meta-analysis at this point. To the extent additional research is needed, it should explore peripheral costs borne by communities and regions outside of the ratepayers directly to understand the way delays impose addition costs not internalized in the planning and cost allocation considerations.

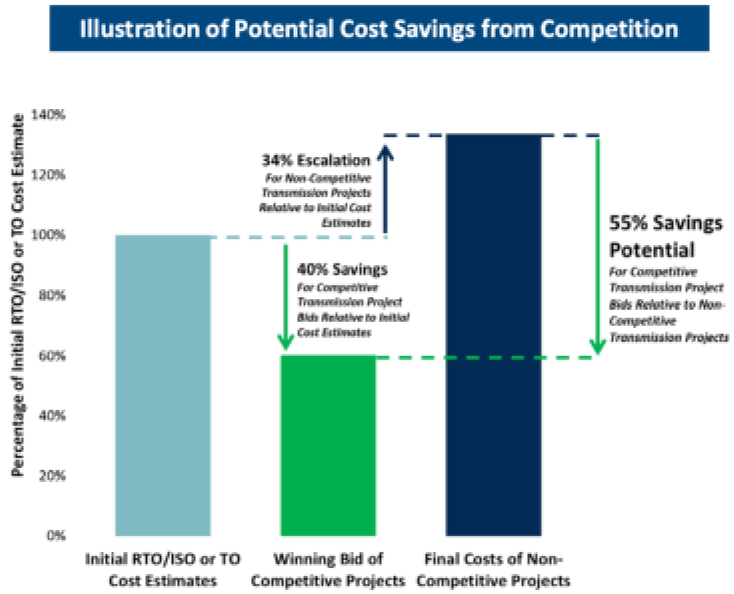
Battling Stakeholder Perspectives on Evaluating Time and Costs

As the literature review demonstrates, the debate over FERC Order No. 1000's impact on a federal right of first refusal and competition has centered on a back and forth between two stakeholder groups:

- April 2019, The Brattle Group Study (LSP Transmission Holdings, LLC)
    - **Cost Savings Offered by Competition in Electric Transmission**: *Experience to Date and the Potential for Additional Customer Value*
- June 2019, Concentric Energy Advisors Critique (DATA)
    - **Building New Transmission**: Experience to-date Does Not Support Expanding Solicitations
- August 2019, The Brattle Group Response
    - **Response to Concentric Energy Advisors' Report on Competitive Transmission**
- August 2022, Concentric Energy Advisors update (DATA)
    - **Competitive Transmission**: *Experience to-date Shows Order No. 1000 Solicitations Fail to Show Benefits*
- December 2023, DATA White Paper to FERC
    - **Revisiting the Evidence on Cost Savings from Transmission Competition**
- April 2024, Concentric Energy Advisors update (DATA)
    - **An Updated Examination of FERC Order No. 1000 Projects:** Expanded Review Shows That Benefits of Competition Remain Elusive

The volley back and forth has centered on cost metrics. The evolution of the debate has shed interesting light on the question, as the later reports seek to utilize the same set of projects and methodology but update project costs for those that were not completed when the earlier report(s) were written. With this argument, time was the only factor needed to invalidate the findings of cost savings as projects matured. Subsequent debate thus centers around whether cost escalations are expected, appropriate, or conclusive in determining the merits of solicitations/competitive bidding versus an incumbent federal ROFR.

The claims of cost savings and cost escalations are often described in the extremes and leverage favorable assumptions and framing. For instance, Brattle alleges that what is at stake is a 55 percent swing and could result in as much as a $9 billion difference for ratepayers over five years.[52] Over time, the series of reports becomes more modest in its claims.



Aii Figure 2: Figure from Brattle Report

In *Aii Figure 2*, generated by Brattle in 2019, The Brattle Group presents its findings that show a significant ***potential*** cost savings from competition relative to traditional, non-competitive transmission projects. To sustain this, they use real quantitative data from historical projects as well as then-current information from competitive projects. In other words, it is a real data-based graphic.

However, it does rely on the most charitable assumptions in favor of competition and the least favorable assumptions for traditional projects. The cost escalations for traditional projects are based on historical data that include skewing data points.[53]

The report also fails to address the key issue at this stage, which is final costs. By using the "winning bid of competitive projects," the report chose a moment in time before any cost escalations and final costs are known. At the time, this was a compelling argument, but in the face of final project costs does not contribute to the discussion. The winning bid of a project cannot be compared to the final cost of another project.

Concentric reports were criticized for utilizing updated cost estimates throughout the lifecycle of a project, comparing final project costs in some instances with more favorable updated estimates rather than the initial estimate.[54] The argument for using updated or final estimates is reasonable, as project development is complicated and dynamic. It nevertheless allows some cost escalations to be baked into the process and makes it more difficult to assess the true and complete cost escalation from beginning to end.

Concentric does address this issue in its latest report from April 2024, in which it compares projects of both incumbent utilities and non-incumbent developers under the solicitation model and compares incumbent and state ROFR projects. By showing that incumbents perform comparably to non-incumbents within the solicitation process, Concentric undermines an aspect of the cost escalation argument used by both sides.

Outside of Brattle and Concentric, many stakeholders and interested parties do not conduct their own economic or statistical analysis, but simply repeat their findings. In those contexts, using framing most favorable to the group's point is common. It leads to a type of report that policymakers should reject.

Time Leads to Escalations
Cost escalations can impact any infrastructure project. Our own framework explains how undertaking a *cumulative cost-benefit analysis* reveals a ballooning effect to most interconnected energy projects.[55] That is very often because of unseen costs like time itself or permitting compliance, along with issues that time can open the opportunity for, like lawsuits or supply chain disruptions. It is also because many infrastructure projects are dependent on one another, like the solar farm and transmission lines each needed to connect energy to users. Policymakers must see each project (the energy generator and transmission project), conduct comprehensive cost-benefit analyses of each, then add the two together to see the cumulative effect.

Cost Escalation Conditions Explained by Brattle

"These cost escalations reflect factors such as inflation during the often lengthy project development process as well as costs associated with conditions imposed during the **siting and permitting process**."	"These cost escalations relative to initial estimates typically relate to factors such as **inflation, routing adjustments, or environmental permitting-related conditions** not reflected in the initial estimates."
"These cost escalations may be driven be inflation during the multi-year project development process and added costs to comply with **conditions imposed during the permitting and siting process**"	"a portion of the observed escalations reflect inflation and justified **design changes** between the point in time when the initial estimates were made and the time when the projects were placed into service"

Because we know cost escalations can affect both incumbents and competing transmission builders, it is worth evaluating whether one is more prone than the other. There may be reasons to believe that independent developers entering a region through competitive solicitations could be more prone to certain cost escalations than incumbent transmission builders are likely to experience. While data is not always transparent or available, and it is difficult to compare cost caps between projects because there are many factors at play, in certain contexts incumbents may be expected to deliver at a more predictable cost than independent developers, especially if the latter are new to the region.

Incumbents may be uniquely positioned to avoid certain of the cost escalations commonly identified with transmission projects and many inherent to the competitive bidding process that brings outside non-incumbent developers into a new region. They must also bid or establish effective subcontracts and work, potentially fulfilling a competitive effect and undermining one argument in favor of the solicitation model.[56]

> 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.[57]

These factors and the inherent delays led former FERC Commissioner Anthony Clark to explain that "This is a matter of theory vs. practice. And it is delaying projects and increasing costs to consumers…The bidding process alone adds at least a year — if not years — to project timelines."[58] If inflation is the most common source of cost escalation (as Brattle repeatedly notes), then to save money, the process that adds a year or more will necessarily be impacted more by inflation.

A final note, which Clark raises as well, is that the solicitation process can lead to "wildly unrealistic" bids. When bids are low, they are more susceptible to escalations in the face of reality. The non-incumbent may propose a substantially lower cost, but have to revise plans along the way, expecting that the scale of their cost savings will serve as a buffer or that cost containment measures will justify certain increases as allowable.

This is another distinction between the incumbent process and a solicitation model, as incumbents estimate project costs based on their experience and the needs of the grid, while competitive developers may try to meet needs without localized or specialized knowledge and have to revise up their final costs. This likely means that for ratepayers, incumbent utilities lead to more predictable cost outcomes.

Impact of Process on Cost Escalation

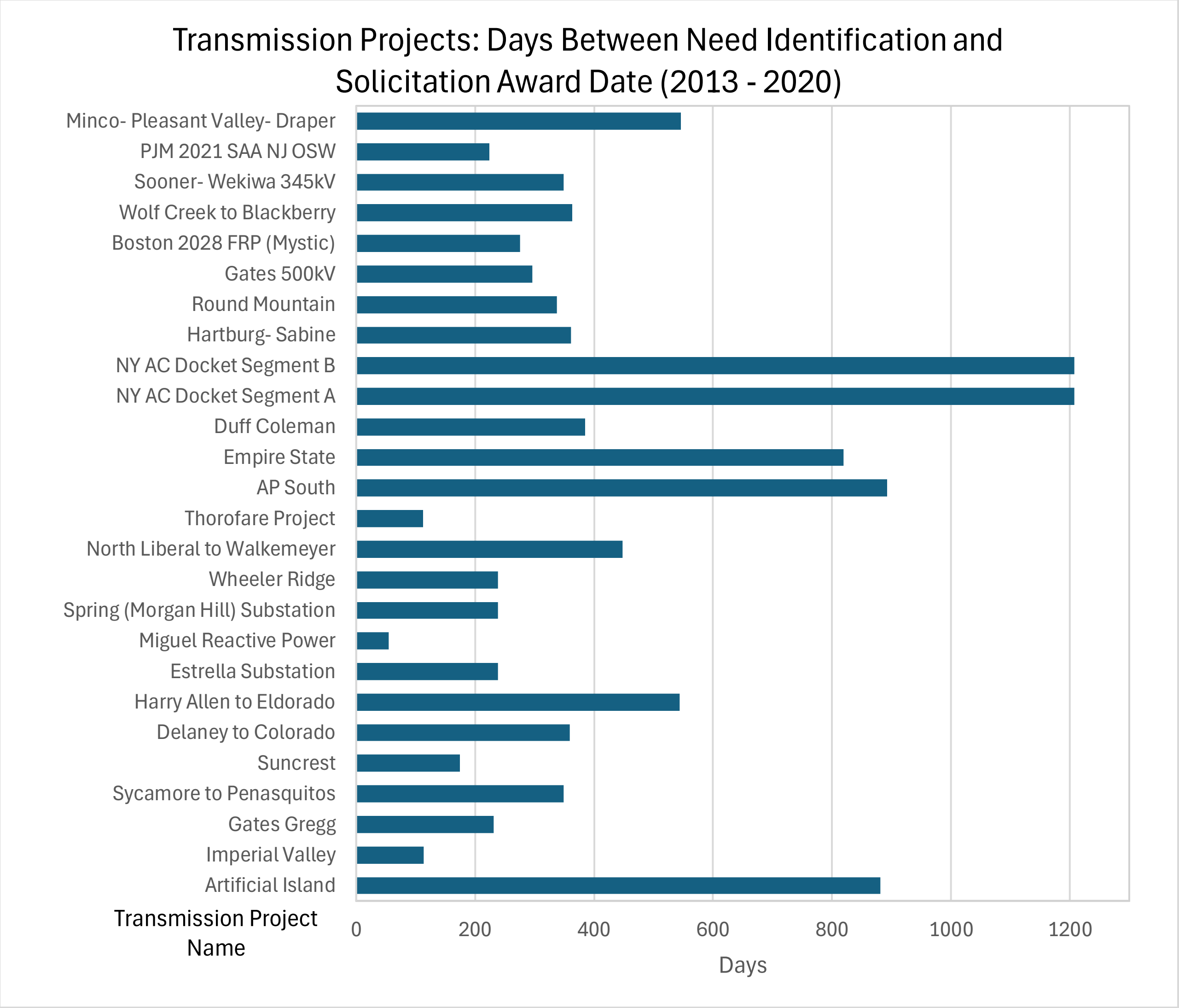
A common development adage is that projects often come in over budget and behind schedule. Whether due to unforeseen circumstances, miscalculations, or changes to the plans throughout the building process, these manifest in delays and higher costs. That matters when the proposed transmission expansion project comes with as much as a $100 million price tag. Modest inflation compounded with delays – if not appropriately factored into the initial proposal – can mean tens of millions of dollars in added costs. Importantly, that is just to the project itself. Delays also cause rippling effects that generate costs for others, such as lost productivity, lack of power, postponed/delayed investment, and more.

New Jersey Transmission Towers (credit: Julien Maculan)

For these reasons, timing and costs are critical to the overall evaluation of the process. It is also true that they apply to both incumbents and independent transmission builders. However, only one of those processes has a specific delay built into it. For this reason, general cost escalations are not the chief issue, but the specific issue of the time value of administering a competitive process.

> 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…[59]
>
> Participating in regional transmission planning processes and competitive transmission procurement processes…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…[60]

With regard to time and delays, competitive bidding pushes the construction and ultimately in-service dates back by over a year on average.



Aii Figure 3: Time to administer the competitive bidding process.[61]

Looking at 26 competitively bid projects between 2013 and 2020, there was an average of 432.5 days between need identification and selection of a winning bid.[62] This is the first delay to in-service dates. It leads to another review, which is whether the developer met the ISO required date for completion and service. Not all in-service date delays are a result of the bidding or competitive process, but they represent delayed implementation that is common from competitively bid projects. Of these projects, 46 percent went into service after the ISO required date or were withdrawn, and 19 percent were canceled/suspended/held.[63] Another 15 percent have still anticipated completion and in-service dates, which may or may not meet the ISO in-service date. This leaves 19 percent that met or beat the in-service date.

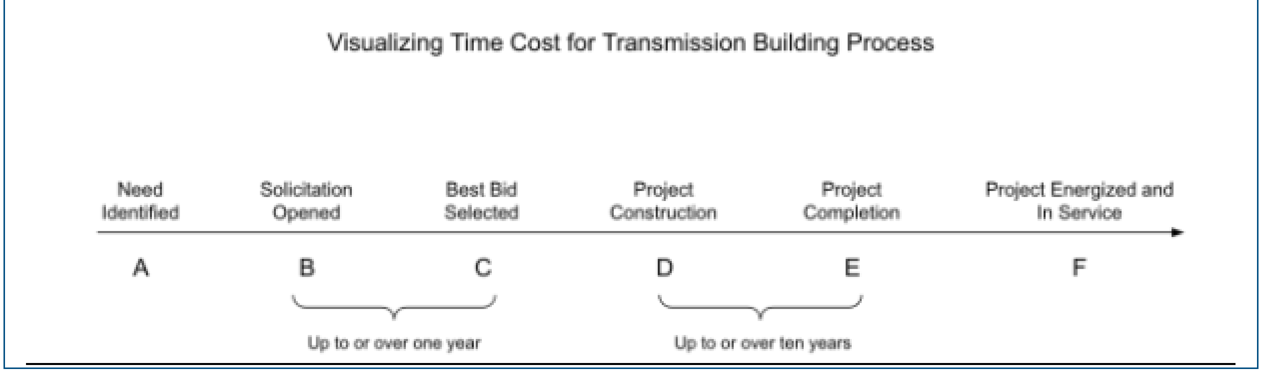
Whether or not a traditional incumbent process can offer cost savings or experience any escalations, the delay from administering the solicitation process is unique – and inherent – to the competitive model itself.

As we have expressed, delays mean time, and time leaves open the opportunity for unknown factors to increase costs. One study found that "delays in power transmission projects have a significant adverse effect on the economic development of a country," and listed 82 potential causes of delays.[64] The longer time between identifying a need and beginning the project leaves open the door to many of these causes to arise, thus creating further delays. Recent modeling demonstrated that "if transmission lines are delayed, prices become higher and more volatile" and that "a delay of even one year in delivering new transmission results in higher bills."[65] Delays mean longer unresolved congestion costs, which can soar into the billions annually as existing infrastructure and energy assets are relied on rather than more efficient ones.[66] Given that time also represents opportunities for inflation, supply chain disruptions, and contract issues, it makes sense that "generally, the earlier each transmission project becomes operational, the lower the wholesale energy costs are."[67]

The sooner a project is initiated, the more cost-effective it is likely to be. Added delays to decide which entity will develop a project effectively act as a tax on the project itself. With projects typically taking years already, adding a year means new costs and postponed consumer benefits as the market awaits the power.

> Transmission projects require at least 5–10 years to plan, develop, and construct; as a result, planning has to start early to more cost-effectively meet the challenges of changing market fundamentals and the nation's public policy goals in the 2020–2030 and 2030+ timeframe.[68]

On the front end, these delays mean more potential for cost escalations in the final project cost that is then allocated to ratepayers. On the back end, it means power not available to customers, which represents opportunity cost and unrealized productivity for whole communities and regions, an indirect and more difficult cost to understand and calculate.



Aii Figure 4: Overview of Timeline

To better conceptualize the direct and indirect costs of time and delays in transmission infrastructure building, we can compare notable generalized project stages.[69] When we consider that A represents a need the planners have identified,[70] the financial clock starts ticking then, because it means somewhere there are unrealized gains or even losses from a gap in power supply and demand.

Most incumbent and pro-ROFR literature emphasize the period between A (need identification) and C (competitive bid selection) as a key delay (adding a year or more). Need identification to Bid selection is a necessary and inherent delay for the competitive model. The data-driven non-incumbent and pro-competition literature emphasize the cost differential between A (need identification) and C (best bid selection). The focus between A and C is key to the purported cost savings of up to 30 percent, because it compares initial estimates with initial winning proposals, but before project completion.

The reason the DATA reports emphasizes time and delays is that when comparing A to E, the savings proposed by The Brattle Group report do not materialize because of costs after C. Even if there are cost savings, a complete understanding of costs must be layered, evaluating A (need identification) to E (project completion) assessed for direct costs **and** A (need identification) to F (project in service) assessed for indirect costs.

Time between A and E in the first evaluation will elucidate project cost escalations and determine the ultimate cost savings or overruns, which are relevant to cost allocations and what ratepayers experience. Only by going all the way to E (project completion) can we know final or mature costs, which replace C (best bid selected). The second assessment is for the market and region awaiting power all the while. The delays between B and C, and D and E do not just inflate the cost of the final project – which ratepayers will eventually pay – they inflate the ripple effects that prevent growth and exacerbate losses regionally.

Indirect costs include at least two major categories: (1) inefficiency and congestion for the existing grid (which ratepayers do see) and (2) unrealized gains or opportunity cost from untapped investment and potential until the power is accessible (which may be less visible).

The price tag for grid congestion has been increasing. It does not just affect ratepayers in a given region, but can have larger effects. Key to this issue are delays:

> "The Federal Energy Regulatory Commission has been warning of grid reliability issues…as well as problems and delays in connecting new generating sources to the grid…."[71]
>
> "Yet, a large amount of potential clean power capacity is struggling with the wait times and costs of connecting to the transmission grid… Permitting and allocating costs for transmission also pose barriers, both for generator interconnection and regional and inter-regional grid infrastructure."[72]
>
> Customers near sources of wind or solar power often enjoy cheaper power than those farther away, because there's insufficient transmission infrastructure to move the cheap power long distances. These "congestion costs" have increased from around $1 billion in 2002 (in 2023 dollars) to more than $13 billion in 2021.[73]

The second type of indirect costs include entrepreneurs not starting projects, investors sitting on funds, businesses delaying expansions, and more. Removing B (solicitation opened) and C (best bid selected) from the process could immediately remove a year or more of potential delay between a need arising and power flowing. A more comprehensive analysis and appreciation for time would layer the cost impact of the direct project with the region awaiting the project.

An example may be useful – consider high-power-demand industries on the cutting edge of revolutionizing how we process data, produce content, and interact with the world. They not only demand power now, but lacking power means setbacks to progress.

> The inescapable topic—and the cause of equal parts anxiety and excitement—was AI's insatiable appetite for electricity. It isn't clear just how much electricity will be required to power an exponential increase in data centers worldwide. But most everyone agreed the data centers needed to advance AI will require so much power they could strain the power grid and stymie the transition to cleaner energy sources.[74]

From the large customer standpoint like big manufacturers and datacenters, they have huge power needs. The process that delivers on those demands without adding unnecessary delays is in their best interest to get shovels in the ground faster. A lack of enough power for cutting-edge companies results in setbacks for technological progress. Adequate power infrastructure connecting generation to users will unleash greater innovation.

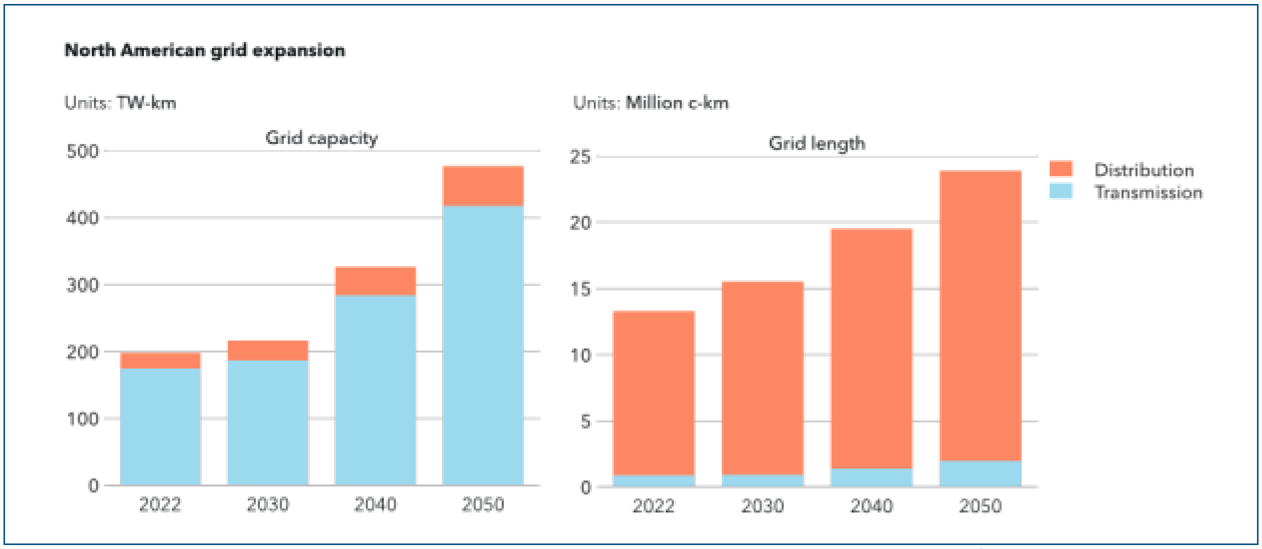
Transmission and Distribution Lines, Bethesda/Potomac Maryland (credit: Cathy Cardno)

The Role of Technology and Innovation

Within many of the arguments raised for the most cost-effective and time-sensitive transmission building process are stressors on the importance of grid enhancement and technology. While every aspect can be evaluated in terms of economic costs, these are primarily expressed in terms of resilience, sustainability, survivability, and more.[75,76] These relate to monitoring, maintenance, upkeep, and repairs over time.

While the issues do not map perfectly to ROFR or competition, they have tended to express that incumbent utilities are less likely to adopt new technology, while new vendors are more likely to enter with innovative approaches. This is counterbalanced with the advantage of incumbents having experience and success in maintaining and operating their infrastructure in the particular area, which may result in cost savings relative to a new builder.

Ultimately, technology and innovation are critical because transmission expansion involves at least two dimensions. Future grid expansion will require improvements in both capacity and total length of new infrastructure lines.[77] This will mean infrastructure capable of bringing more power through the network and more total infrastructure to build, monitor, maintain, and upgrade over its lifecycle.



Aii Figure 5: Expansion of Grid Capacity versus Linear Mileage[78]

In as much as pro-competition voices allege that incumbents fail to invest in innovation, it is also a common response that competitive selection is overly focused on costs. That is, the project with the lowest cost is often selected as the winner. While other factors are weighed, innovation itself (or the use of new technologies) is not universally prioritized in the selections.

There are contexts in which incumbents are more likely to leverage innovative technology, which primarily relate to system upgrades and resilience improvements. There is an argument by independent developers that incumbents do not have incentive to incorporate innovative

> "Future grid expansion will require improvements in both capacity and total length of new infrastructure lines."

technology or new techniques that would lower costs, or that they lack incentives to conduct upgrades in the first place. This is not supported by data. In fact, the record not only undermines this theory, but indirectly undermines a different allegation against incumbents – that they have avoided regional build outs that are subject to FERC Order No. 1000 to skirt competitive processes and stay within their service territory. The order specifically contemplates the need for such maintenance activity.[79]

Incumbents have not avoided regional build outs for the sake of avoiding competition, but in many cases their activity on their own existing lines was in fact to conduct needed upgrades and resilience enhancements. These enhancements can also expand capacity, negating the need for new transmission lines in the first place. In fact, reconductoring in existing rights of way corridor is one way experts believe the lion's share of grid expansion can be conducted.[80,81,82]

> We find that when reconductoring is an option, it is favored over building new lines due to its lower cost… considering that new lines often take 10-15 years to complete, reconductoring presents a synergistic opportunity for expanding transmission capacity in the near-term while new lines are planned and permitted.[83]

The importance of time cannot be overstated – this would streamline many issues like permitting and siting, enable incumbents already in their own territory to conduct work in the area they are familiar, and reduce the scale of lengthy construction like new towers. As others have noted, the FERC process and even reforms take valuable time away from working on needed capacity expansions: "While recent initiatives from the Federal Energy Regulatory Commission (FERC) aim to enhance planning and interconnection policies, their implementation will take time, necessitating concurrent near-term solutions."[84]

Conclusion

Building new transmission infrastructure is critical to the future of the United States. Without new high-voltage capacity and grid connections, energy and economic growth will stagnate. Fortunately, the importance of transmission infrastructure is agreed upon. The primary obstacle is the disagreement over who will build this new infrastructure and what process will govern the rights of incumbent utilities and competing developers.

Planning and cost allocation rules have created a direct contrast between the previous model that included a federal right of first refusal and the model that requires competition in transmission building. These lead to different project timelines and cost outcomes, which ratepayers then see reflected in power bills.

More research would be useful in this industry, but existing data demonstrates the basic findings that the competitive bidding process required by FERC Order No. 1000 did increase the time between need identification and in-service dates, as the competitive processes often takes a significant amount of time and cost to administer. This has likely influenced ratepayer costs.

The state of the literature to date includes most pro-competition entities citing The Brattle Group report from 2019 and little else for quantitative analysis of costs. New reports dating since that time often simply repurpose elements of the Brattle analysis to make the same point. On the other side, incumbent utilities, primarily through the DATA coalition, have produced or sponsored several new analyses that suggest competition solicitation has not lowered costs.

From those more recent analyses, and an independent assessment of both the literature and the underlying framework at issue, it is clear that time is its own cost that is not adequately internalized in the process. It leads to higher costs for ratepayers and for the wider economy by delaying major projects and the economic activity that could take place. The more time it takes to identify and put into action a plan to develop transmission infrastructure, the more opportunities arise for cost escalations. Policymakers should understand the impact of time and view it as the direct and indirect cost that it imposes on projects.

Yes, delays and added time to plan, build, and energize a transmission line will have an impact on the ratepayer, but there are economic impacts outside of the cost allocation scope to consider. FERC, state legislatures, and other policymakers should consider these impacts as they contemplate reforms. Because policymakers are tasked with broad public trust and are responsible for a broad set of issues, they should have a vantage point high enough to see the impacts generated by their rules, even if they fall outside their specific jurisdiction.

The time impact of transmission building is one of those areas. The time from need existence or identification to the time that the project is energized represents an impact on the broader region and even the national economy. Planning and cost allocation rules that lengthen that time will necessarily generate negative externalities. Rules that reduce that time will not only deliver cost savings for transmission projects themselves and for ratepayers but will reduce the indirect and background economic costs for the interconnected and dependent markets awaiting the realization of the power project.

Appendix A

The project in question is the Artificial Island project opened by PJM. An initial bid package by incumbent PSE&G included a low proposal of $692 million and other proposals far exceeding that.[85] The winning bid was made by LS Power at around $275 million.[86,87] This produces a 60 percent cost saving from competition. PSE&G made a revision late in the process to modify its bid to $285 million to more closely match the parameters PJM was considering,[88] which was essentially deemed moot because it was not lower in cost or more favorable in overall quality relative to the already evaluated bids.[89] As PJM noted in its recommendation,

> We note that on July 24, 2015, PSE&G submitted a modification to its proposal. This late-filed submission came too late in the process to afford all stakeholders due process and an opportunity to review the revised proposal. As a result, it was not considered as a timely modification of PSE&G's proposal. However, even if PJM had considered the latest PSE&G modification, it does not modify the PJM staff's recommendation…[90]

Regarding the comparability of the bids,

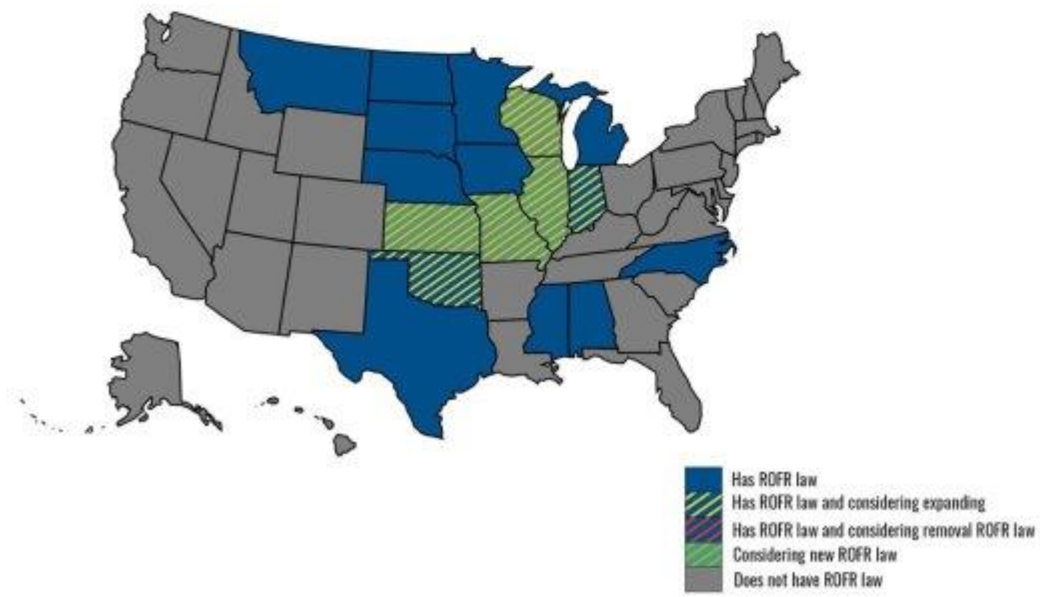
> The proposals put forward represent a technologically diverse set of partial and complete solutions to the reliability issues identified by PJM in the RFP. The projects are not directly comparable because they include both partial and complete solutions to the Artificial Island reliability issues, though correcting for differences it appears that the incumbent [originally] made by far the most-costly proposals and did not offer to agree to cost-containment commitments.[91]

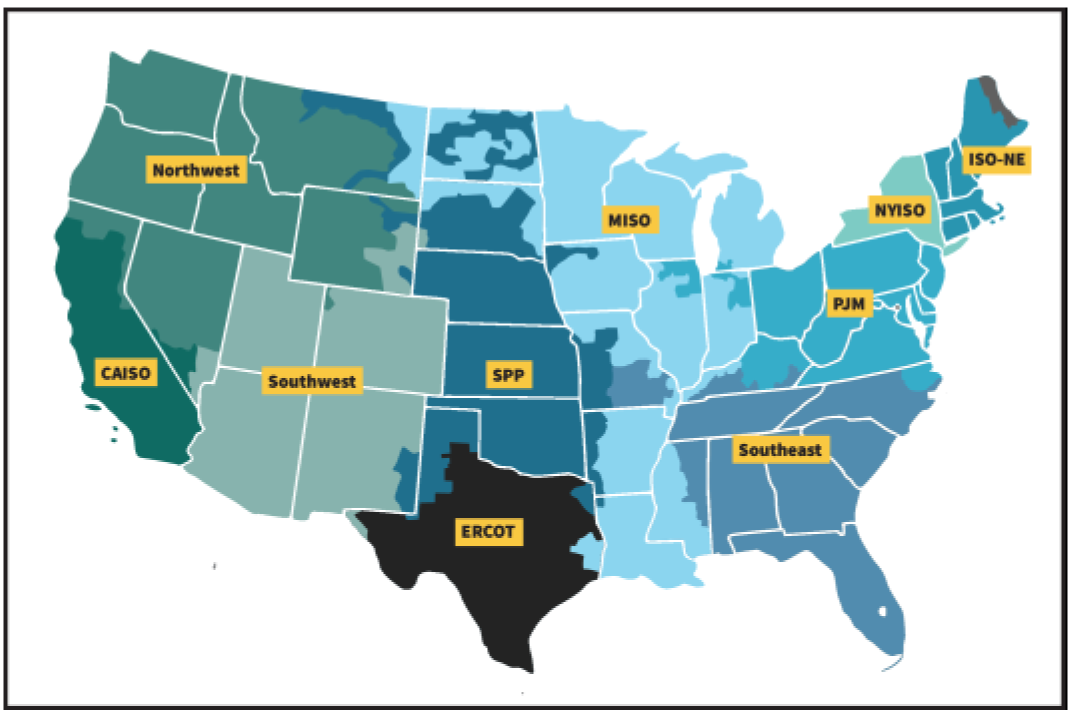
The revised incumbent bid of $285 million was much more comparable to the selected non-incumbent bid of $275 million.

The average 40 percent savings is created by summing the initial costs of a number of competitive projects and comparing that with sum of the corresponding selected bid costs.[92] Complicating matters further, PJM suspended the project in 2016, reevaluated needs and the scope of the project, and lifted the suspension in 2017, retaining LS Power as its selected builder.[93,94,95] It also straddled the period when FERC Order No. 1000 was final and enforceable, making it dubious to include in the analysis, especially when the values selected lead to obvious skewing of the overall report findings in favor of higher purported cost savings.

Appendix B:

Further complicating the competition is that RTO/ISO service territory often overlaps with numerous states or has portions that reach into a state.





Map from FERC.[96]

Appendix C:

In the table below, delay may be viewed through the time to solicit and evaluate bids and in the expected/required in-service date compared with the actual date of completion and in-service date.

Competitive Projects and Timing Considerations

Name	ISO/ RTO	Need Identification Date	Solicitation Awarded date	Days Between Need Identification and Selection	Original ISO Required in-service date	Planned or Actual In Service Date	Incumbent (I)/ Non-incumbent (NI) selected
Artificial Island*	PJM	2/28/2013	(initial) 7/29/2015 (revised) 4/6/2017	881 1,498 (total)	April 2019	May 2020	NI
Imperial Valley	CAISO	3/20/2013	7/11/2013	114	2015	Canceled/ Suspended	NI
Gates Gregg	CAISO	3/20/2013	11/6/2013	231	May 2022	Canceled/ Suspended	I
Sycamore to Penasquitos	CAISO	3/20/2013	3/4/2014	349	July 2018	August 2018	I
Suncrest**	CAISO	7/16/2014	1/6/2015	174	June 1, 2017	February 2020	NI
Delaney to Colorado (Ten West Link)***	CAISO	7/16/2014	7/10/2015	359	May 2020	April 2024	NI
Harry Allen to Eldorado	CAISO	7/16/2014	1/11/2016	544	May 2020	Aug. 2020	NI
Estrella Substation	CAISO	7/16/2014	3/11/2015	238	May 2019	November 2029	I/NI
Miguel Reactive	CAISO	7/16/2014	9/9/2014	55	June, 2017	July 2019	I (sole bidder)

Power							
Spring (Morgan Hill) Substation	CAISO	7/16/2014	3/11/2015	238	May 2021	2027	I
Wheeler Ridge	CAISO	7/16/2014	3/11/2015	238	May 2020	indefinite hold	I
North Liberal to Walkemeyer	SPP	1/20/2015	4/12/2016	448	6/1/2019	Canceled/ Suspended	I
Thorofare Project	PJM	2/17/2015	6/08/2015	112	12/31/2019	10/10/2019	NI
AP South	PJM	2/28/2015	8/9/2016	893	6/1/2020	Canceled/ Suspended	NI
Empire State	NYISO	7/20/2015	10/17/2017	820	June 2022	July 2022	NI
Duff Coleman	MISO	12/1/2015	12/20/2016	385	Jan. 2021	June 2020	NI
NY AC Docket Segment A	NYISO	12/17/2015	4/8/2019	1208	12/31/2023	December 2023	NI
NY AC Docket Segment B	NYISO	12/17/2015	4/8/2019	1208	12/31/2023	December 2023****	I
Hartburg-Sabine	MISO	12/1/2017	11/27/2018	361	June 2023	Withdrawn	NI
Round Mountain	CAISO	3/27/2019	2/28/2020	338	June 2024	2025	NI
Gates 500kV	CAISO	3/27/2019	1/17/2020	296	June 2024	2025	NI
Boston 2028 RFP (Mystic)	ISO-NE	10/17/2019	7/19/2020	276	6/1/2024	6/15/2023	I
Wolf Creek to Blackberry	SPP	10/29/2019	10/27/2021	363	1/1/2026	2025	NI
Sooner-	SPP	10/29/2019	10/13/2020	349	1/1/2026	2025	I

Wekiwa 345kV							
PJM 2021 SAA NJ OSW	PJM	11/18/2020	6/30/2021	224	6/31/2029	2027-2029	NI
Minco-Pleasant Valley-Draper	SPP	10/27/2020	4/26/2022	546	1/1/2025	2024	NI

*Artificial Island had some political problems and cost overruns that made it more difficult to accurately assess. Also involved multiple companies doing different parts.
** Construction didn't begin until "early 2019" due to a pending Environmental Impact Review. California Public Utilities Commission cleared the project in October 2018.
***construction didn't begin until October 2022.
**** "The Developer of Segment B informed the NYISO and stakeholders that there is an expected delay to one of the components—the Dover substation and PARs on the tie line to ISO-NE—due to a legal challenge to the local permit that resulted in an injunction to further develop the site."[97]

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[11] *See also*, Appendix C.
[12] Provided they utilize a reliable methodology and current data (in other words, the presumption should not apply to a report citing old numbers merely because it was published more recently).
[13] Joskow, P. (2019) *Competition for Electric Transmission Projects in the USA FERC Order 1000*. Massachusetts Institute for Technology. https://ceepr.mit.edu/wp-content/uploads/2021/09/2019-004.pdf.
[14] CAPX. (2013). *Transmission line construction process*. South Dakota Public Utilities Commission. https://puc.sd.gov/commission/dockets/electric/2013/EL13-020/transmissionline.pdf.
[15] ISO = Independent System Operator, often used in connection with or in place of RTO = Regional Transmission Organization. There may also be use of TSO = Transmission System Operator.
[16] *Supra* note 13.
[17] *Id*.
[18] Weiler, S. A. (2013). *'pomp and unchanged circumstance': FERC attempts to eliminate federal rights of first refusal*. The Electricity Journal, 26(3), 14–27. https://doi.org/10.1016/j.tej.2013.03.004.
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[30] In particular, the report uses its range to produce low-end and high-end potential savings. This includes multiplying 20 percent savings by one-fourth of new transmission projects and a high end of 30 percent project savings multiplied by one-third of new transmission projects.
[31] *Id*.
[32] *See* Appendix A for discussion.
[33] Numerous other reports cite 20 percent to 30 percent savings or 40 percent savings from Brattle but do not conduct their own analysis or review the methodology for the numbers.
[34] ETCC. (2024). *Who we are*. Electricity Transmission Competition Coalition. https://electricitytransmissioncompetitioncoalition.org/who-we-are/
[35] From the Brattle Report. (e.g., Note 33)
[36] For reasons discussed below, the purported 40 percent savings for the average competitively bid transmission project is an overestimation, and the increase to one-third of all new transmission being competitively bid is an unrealistic leap from the status quo.
[37] This author was unable to find reference to $2.1 trillion in the cited source. $2.2 trillion is the closes and is taken here to be the intended referent.
[38] E. Larson, C. Greig, J. Jenkins, E. Mayfield, A. Pascale, C. Zhang, J. Drossman, R. Williams, S. Pacala, R. Socolow, EJ Baik, R. Birdsey, R. Duke, R. Jones, B. Haley, E. Leslie, K. Paustian, and A. Swan, *Net-Zero America: Potential Pathways, Infrastructure, and Impacts, Final Report Summary*, Princeton University, Princeton, NJ, 29 October 2021.
[39] Specifically, the 3.1 times capacity is a high-end estimation that exceeds many expected (high end) estimates, including: DNV (2.5 times), U.S. EIA ("nearly double"), See, DNV, U.S. electric capacity mix shifts from fossil fuels to renewables in AEO2023. EIA. (2023, April 13). https://www.eia.gov/todayinenergy/detail.php?id=56160.
[40] Increases in nuclear, hydrocarbons, hydrogen, and distributed energy solutions can all achieve similar or higher energy capacity without the expansive transmission needs because they have a low land-use footprint and can be built near population centers or existing grid infrastructure. The ETCC use of the solar and wind scenario merely rejects a more realistic future in favor one the estimate that generates the largest figure for their calculation.
[41] The mathematical logic is the same as above, applying 40% savings to 100% of transmission projects and using the $2.1 trillion figure. This is not only infeasible but impossible, as 100% of transmission projects would require all state ROFR laws be eliminated or entirely preempted by federal action. Moreover, for reasons articulated in this paper, the 40% figure is inaccurate and the $2.1 trillion figure is unrealistic.
[42] Which largely center on one study and its findings, and which are likely overstated in degree or inaccurate altogether.
[43] "This is a matter of theory vs. practice" said Clark, adding that in practice, FERC's competitive bidding theory hasn't worked. "And it is delaying projects and increasing costs to consumers," he said. "The bidding process alone adds at least a year — if not years — to project timelines." – Tony Clark, former commissioner at the Federal Energy Regulatory Commission (FERC).
[44] Developers Advocating Transmission Advancements (DATA*). Supplemental Comments of Developers Advocating Transmission Advancements re Notice of Proposed Rulemaking under RM21-17, et al*. Retrieved from https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231215-5048.
[45] *Id.*
[46] Nicholson, E., Stone, M., & Powers, D. (2019, June). *Building New Transmission*. Concentric Energy Advisors. https://ceadvisors.com/wp-content/uploads/2019/06/CEA_Order1000report_final.pdf.

[47] *Supra* note 10.
[48] This is the report Brattle responded to in 2019.
[49] *Id*.
[50] Gramlich, R., Doying, R., & Zimmerman, Z. (2024, February). *Fostering Collaboration Would Help Build Needed Transmission*. WIRES. https://gridstrategiesllc.com/wp-content/uploads/2024/02/GS_WIRES-Collaborative-Planning.pdf.
[51] Although the literature does not always fully answer whether incumbent projects can deliver savings (rather than simply stick to the initial/proposed estimate) or the extent to which incumbents are best suited to avoid cost escalations.
[52] Brattle estimates that if competitive processes can expand to 33 percent of all projects, and competitive projects save 30 percent on average, then it could save $9 billion in customer value over five years. This is the high end of the estimate, the low end is if 25 percent of transmission projects were competitive and saved 20 percent each, in which case savings would be $4.4 billion. Brattle also estimates that only 3 percent of all projects are currently bid competitively, making an increase to 25 percent or 33 percent a substantial departure from the status quo.
[53] In particular, ISO NE, where escalations average 70 percent over initial estimates. This is a small region and its cost escalation is markedly different from the other ISO/RTO regions, which range from 18 precent to 41 percent. The analysis is also peculiar, because the date ranges are different for each region, with SSP ranging from around 2012-2016, PJM from 2014-2017, MISO from 2015-2017, CAISO from 2014-2016, and ISO NE ranging all the way from 2002-2016.
[54] In "Response to Concentric Energy Advisors' Report on Competitive Transmission" from Brattle, it is argued that the Concentric Energy Advisors report "Building New Transmission: Experience to-date Does Not Support Expanding Solicitations" used updated estimates for a MISO transmission project. The initial 2008 cost estimate for the incumbent project was $360 million, and final 2016 in-service cost was $493 million, constituting a 37% cost escalation. In Concentric's report, they used the average of updated cost estimates from 2014 and 2015: $439 million, calculating the cost escalation of just 12%.
[55] *Supra* note 9.
[56] "The existing utilities own existing right of way. They go out to bid for engineering, material and construction, so I don't see what benefits are brought by utility competition, though I mostly favor a competitive environment in most endeavors"-Frederick Plett, direct communication.
[57] Joskow, P. L. (2019, March). *Competition for electric transmission projects in the U.S.: FERC Order 1000*. MIT Center for Energy and Environmental Policy Research. https://ceepr.mit.edu/wp-content/uploads/2021/09/2019-004.pdf.
[58] Riley, K. (2024, January 11). *Debate intensifies over whether competitively bid electric transmission projects result in cost savings*. Daily Energy Insider. https://dailyenergyinsider.com/featured/42388-debate-intensifies-over-whether-competitively-bid-electric-transmission-projects-result-in-cost-savings/.
[59] Joskow, P. L. (2019, March). *Competition for electric transmission projects in the U.S. : FERC Order 1000*. MIT Center for Energy and Environmental Policy Research. https://ceepr.mit.edu/wp-content/uploads/2021/09/2019-004.pdf.
[60] *Id*.
[61] Table created by Aii, *see* Appendix C.
[62] To be more conservative and reduce outlier effects, this average uses the lower estimate for Artificial Island of 881 days between need identification and award rather than the longer of 1,498 days from initial need identification to the revised solicitation determination.
[63] *See* Appendix C.
[64] Pall, G. K., Bridge, A. J., Skitmore, M., & Gray, J. (2016). *Comprehensive review of delays in power transmission projects*. IET Generation, Transmission &; Distribution, 10(14), 3393–3404. https://doi.org/10.1049/iet-gtd.2016.0376.
[65] Nestor, S. (2022, July 22). *Transmission line delays will increase energy bill cost*. Energy Magazine AU. https://energymagazine.com.au/transmission-line-delays-will-increase-energy-bill-cost.
[66] Doying, R., Goggin, M., & Sherman, A. (2023). *Transmission Congestion Costs Rise Again in U.S. RTOS*. Grid Strategies. https://gridstrategiesllc.com/wp-content/uploads/2023/07/GS_Transmission-Congestion-Costs-in-the-U.S.-RTOs1.pdf.
[67] *Id*.
[68] *Supra* note 26.
[69] Some ISOs conduct long reviews between A and B or C and D (see CAISO environmental reviews, which can take years). Many types of project delays also occur between D and E.

[70] Need means: an electric transmission need refers to the existence of present or expected electric transmission capacity constraints or congestion in a geographic area. See, U.S. Department of Energy, https://www.energy.gov/sites/default/files/2023-10/101623_Needs-Study_Public-Draft-Comments-Compiled_Spring-2023.pdf.
[71] Weiser, S. (2023, December 22). *Astonished at high cost, Colorado regulators scrutinize Xcel's $3 billion transmission line request*. Denver Gazette. https://denvergazette.com/news/business/building-new-high-voltage-colorado-transmission-lines-is-costly/article_e26bccce-a058-11ee-a279-dfdd2499e9aa.html.
[72] U.S. Department of Energy. (2022, April). *Queued Up...But in Need of Transmission*. https://www.energy.gov/sites/default/files/2022-04/Queued%20Up%E2%80%A6But%20in%20Need%20of%20Transmission.pdf.
[73] *Supra* note 7.
[74] Blunt, K., & Hiller, J. (2024, March 24). *Big Tech's latest obsession is finding enough energy*. The Wall Street Journal. https://www.wsj.com/business/energy-oil/big-techs-latest-obsession-is-finding-enough-energy-f00055b2.
[75] Whatever is the argument used for the process, the fundamental issue is that the selected course of action must be able to facilitate *grid resiliency and reliability under severe climactic events*. Competitive bidding should include clauses to demonstrate that the material and design adopted provide adequate disaster resiliency (recovery). Individual structure reliabilities under adverse loads must lead to enhanced line reliability and less outages and thereby less recovery or repair. (Dr. Sriram Kalaga).
[76] That rather than For and Against [competition] - the better question is who is interested in building the line at a specific level of reliability and survivability. -Doug Houseman, direct communication.
[77] *Id*.
[78] Sall, P. (2024, June 18). *Global Grid Infrastructure to double by 2050 to meet surging electricity demand*. DNV. https://www.dnv.com/news/dnv-new-power-systems-report/.
[79] "our reforms are not intended to affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities" FERC Order No. 1000.
[80] Chojkiewicz, E., Paliwa, U., Abhyankar, N., Baker, C., O'Connell, R., Callaway, D., & Phadke, A. (2024, April). *2035 report | Reconductoring with Advanced Conductors can Accelerate the Rapid Transmission Expansion Required for a Clean Grid*. 2035 The Report. https://www.2035report.com/wp-content/uploads/2024/06/GridLab_2035-Reconductoring-Technical-Report.pdf.
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[82] O'Boyle, M., Baker, C., & Solomon, M. (2024, April 9). *Supporting Advanced Conductor Deployment: Barriers and Policy Solutions*. 2035 The Report. https://www.2035report.com/wp-content/uploads/2024/04/Supporting-Advanced-Conductor-Deployment-Barriers-and-Policy-Solutions.pdf.
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[85] PJM. (2015, July 29). *Artificial Island White Paper*. PJM. https://www.pjm.com/~/media/committees-groups/committees/teac/postings/artificial-island-project-recommendation.ashx.
[86] The Artificial Island Project. Delaware Public Service Commission (PSC) - State of Delaware. (n.d.). https://depsc.delaware.gov/artificial-island-project/.
[87] Supra. Project Capital Cost Total Estimate (in 2015 dollars) of $263 - $283 million.
[88] *Id*. Project Capital Cost Total Estimate (in 2015 dollars) of $277 - $285 million.
[89] It can be viewed as a feature of competition that this lower bid was created in the first place, as it was partially in response to other bids. However, that may not explain the entire cost disparity. Narrower or more specific parameters in the called for design and market demand can similarly reduce costs. In this case, it is also noted that "In light of LS Power's submittal, the PJM Board directed PJM to allow PSE&G, Transource Energy and Dominion the opportunity to supplement their proposals as well."
[90] PJM. (2015, July 29). *Artificial Island White Paper*. PJM. https://www.pjm.com/~/media/committees-groups/committees/teac/postings/artificial-island-project-recommendation.ashx.

[91] Hesamzadeh, M. R., Rosellón, J., & Vogelsang, I. (2020). *Transmission network investment in liberalized power market*s. Springer International Publishing Springer.
[92] The report is careful to articulate that "PJM's Artificial Island Project shows that the cost of PJM's selected solution is 60% below the lowest incumbent solution initially submitted." (emphasis added). This means the report retained its accuracy, while leveraging the initial bid to highlight competition. Not only does it enable them to demonstrate cost saving from innovation, but point to subsequent modifications by incumbents as a feature of competition that only emerged because of another proposal.
[93] PJM. (2017, June 29). *Alternative Approaches to Identification of Artificial Island Project Beneficiaries*. PJM. https://pjm.com/~/media/committees-groups/committees/teac/20170713/20170713-stability-project-beneficiary-identification-redline-rev1.ashx.
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The author thanks Mr. Owen Rogers for his assistance with research and preparation of this report.

Recommended Citation for this report

Dierker, B. (July, 2024). *Building New Critical Infrastructure: No Time to Waste. Evaluating Cost Transparency between a Federal Right of First Refusal and Competitive Bidding in Electric Transmission Infrastructure Expansion*. Alliance for Innovation and Infrastructure. Aii.org.

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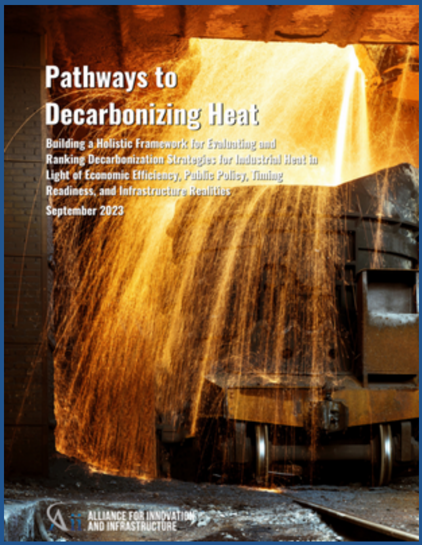

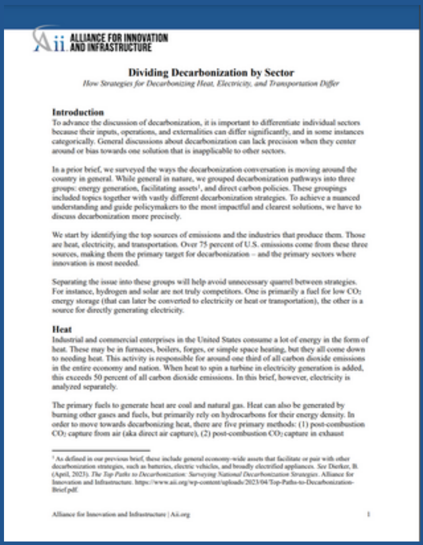

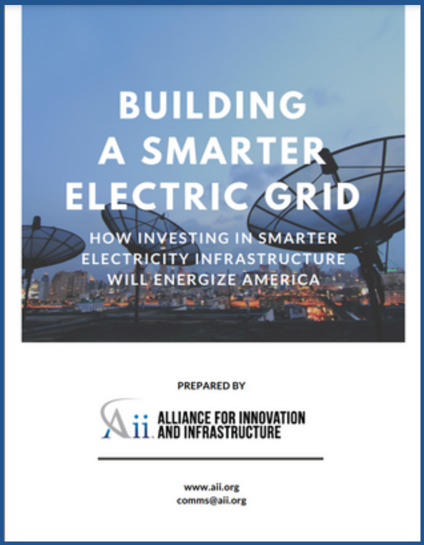

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