TYLER VORPAGEL

STATE REPRESENTATIVE • 27TH ASSEMBLY DISTRICT

Assembly Bill 892: an incumbent transmission facility owner's right to construct, own, and maintain certain transmission facilities.
Testimony of State Representative Tyler Vorpagel
Committee on Energy and Utilities
February 3, 2022

Thank you, Chairman Kuglitsch, Ranking Member Meyers and committee members, for scheduling a hearing today on Assembly Bill 892.

To put this bill in simple terms, this legislation would maintain the state's right to control the expansion and operation of the transmission grid.

When I was approached about offering this bill it was right up the alley of the committee I chaired for 4 years in the Assembly. While the Assembly Committee on Federalism and Interstate Relations may no longer exist, I still believe it is important that we continue to push for states' rights and not allow the federal government or other states to drive our narrative.

You're going to hear later from a former FERC commissioner who will share insights on FERC Order 1000. He will share why that Order has not worked as intended and why the majority of states in our region have adopted similar legislation to this. You're also going to hear directly from our local transmission companies who have worked hard to provide affordable service and ensure we're not paying for service in other states.

I encourage you to listen to all the testimony and be reminded that when it comes down to it, this bill is about state's rights. By passing this bill, Wisconsin would join Michigan, Iowa, Minnesota, South Dakota, North Dakota, Indiana, and Texas in making sure we put our state's needs ahead of the Federal Governments when determining our energy Transmission priorities. We'd like to keep Wisconsin in control of their transmission lines rather than allow the federal government, or states without Wisconsin's best interest, to take over. Thank you for taking the time to listen to my testimony on this bill.

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JULIAN BRADLEY
WISCONSIN STATE SENATOR

Assembly Committee on Energy and Utilities
Thursday, February 3, 2022

Assembly Bill 892

Chairman Kuglitsch and committee members,

We are all likely guilty of taking the availability of power in Wisconsin for granted. But without it families and businesses could not function. Maintaining the efficient delivery of power should be a top priority for both regulated utilities and policymakers here in the legislature and at the Public Service Commission.

Since 2011, seven states within the Midcontinent Independent System Operator region have passed bipartisan laws to ensure the continued availability of power to consumers. This bill would similarly protect Wisconsin's access to reliable power by ensuring that the expansion and operation of our state's electric grid is overseen by the State of Wisconsin rather than leaving our fate in the hands of federal regulators and regional planners.

Allowing MISO, a regional entity formed and approved by the federal government, to dictate who builds crucial infrastructure while our neighboring states take steps to control their own fates would be a troubling abdication of responsibility by Wisconsin policymakers.

As we contemplate future energy needs, policy makers will be asked to weigh the interest of consumers for both affordable and reliable energy. These dual interests will be apparent during today's hearings as different individuals and groups advocate for their point of view. As the committee and public considers these perspectives, I think it is important to highlight a few examples of existing safeguards for rate payers through the PSC process, which would remain in place if this bill became law.

The PSC approves costs for projects through the Certificate of Public Convenience and Necessity process. Consumer groups such as the Citizens Utility Board and the Wisconsin Industrial Energy Group can participate in the PSC process. If there are cost overruns, the PSC reviews them and consumer groups can again participate in the review process.

Wisconsin's existing process at the PSC provides a framework to balance the need for a reliable power grid and the importance of keeping costs and rates low for Wisconsinites.

Thank you for your time. I appreciate your consideration of this bill.

WISCONSIN STATE CAPITOL
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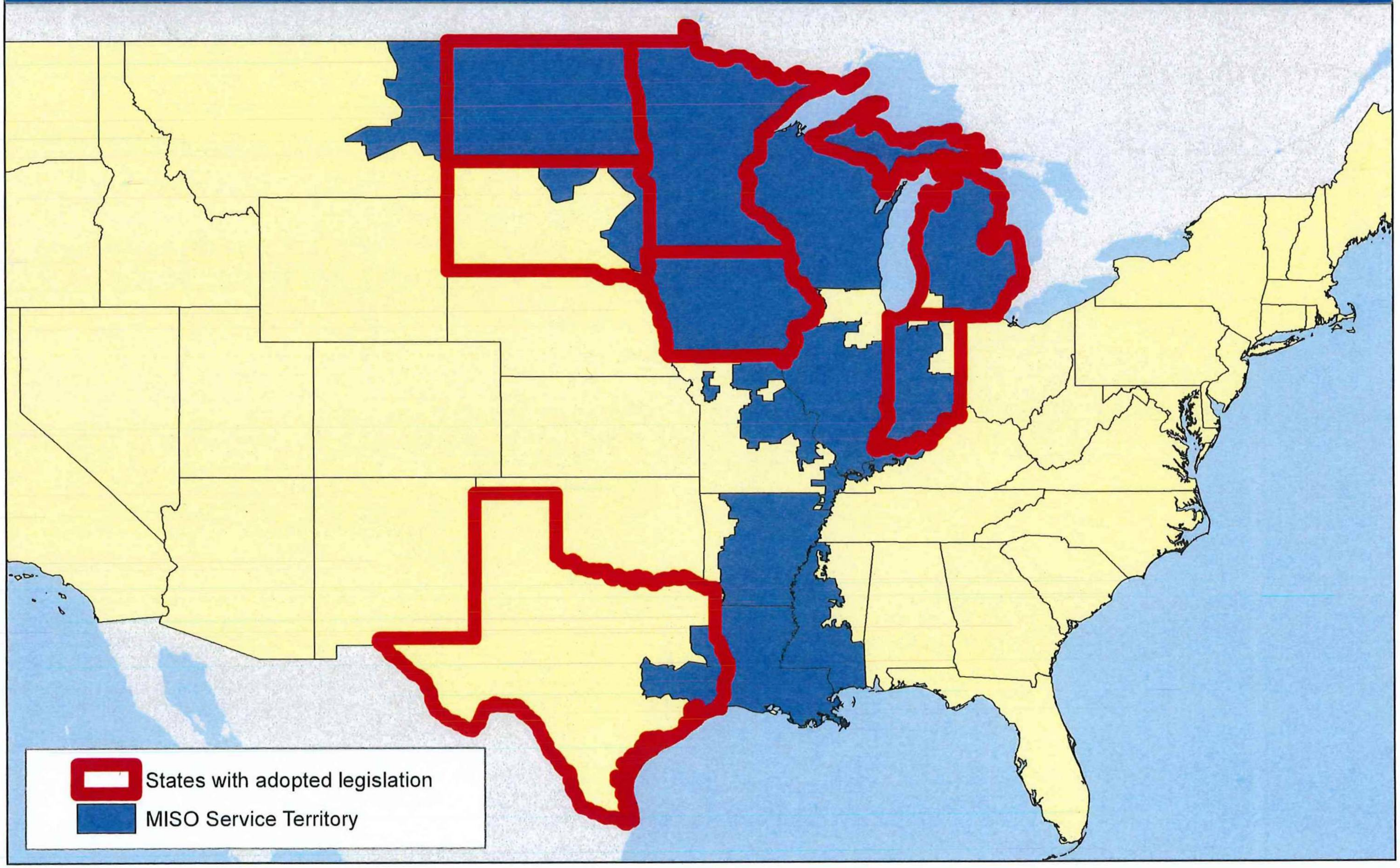
Exhibit 2

States within MISO footprint that have adopted legislation for incumbent utility right to construct, own and maintain transmission.



Thank you for giving me the opportunity to testify today in support of Senate Bill 838/Assembly Bill 892. My name is Bill Marsan, Executive Vice President and General Counsel at American Transmission Company.

This legislation is necessary to maintain the state's right to control the expansion and operation of the transmission grid.

The majority of states in the Upper Midwest have already passed similar legislation. There are several reasons why.

- These states recognize that without this legislation, states are beholden to a mandated, federal process that takes too long, does not deliver promised cost savings, and obstructs the state's ability to oversee that the transmission system remains safe, reliable and meets customers' changing needs:

- There is near universal recognition that the mandated, federal process for building transmission has been a failure. This process puts out-of-state entities in charge of determining who will build and own certain transmission projects within a state:

- The mandated, federal process does not actually prioritize cost-effectiveness of transmission solutions. Indeed, cost-effectiveness considerations are reflected in only 2 of 23 factors considered; and,

- The mandated, federal process has failed to achieve its ultimate policy objective, which was to build more transmission.

Compare the failure of the mandated, federal process with what Wisconsin has achieved.

The Wisconsin Legislature helped establish American Transmission Company in 1999, in response to growing concerns over the reliability of the state's electric grid. At the time, Wisconsin had one of the weakest transmission systems in the United States.

The creation of ATC as a stand-alone transmission company that combined multiple systems has been a remarkable success. In two decades, ATC has built a system that now has 10,000 miles of lines and nearly 600 substations. Since beginning operations in 2001, we have built more than 1200 miles of new lines and close to 40 substations in Wisconsin, as well as improved about 75% of our existing lines and all our substations in the state. Through this work, we have improved the overall reliability of the system – in some metrics by as much as 33%.

ATC consistently builds projects on time and under budget. For example, over the last 10 years ATC has completed 26 transmission projects that required Wisconsin Public Service Commission approval. On average, these projects cost 12% less than the budget ordered by the commission.

Despite what some opponents contend, ATC's support for this bill is not an effort to prevent competition. On the contrary, we have and will continue to rely on a robust, competitive process to actively manage our projects' construction costs, which are capped and monitored by the Wisconsin commission. These efforts include competitively sourcing transmission equipment and the local workforce that construct our facilities. Claims that the mandated, federal process would enable new companies to reduce transmission costs by 30% are not credible and have been refuted by a study I would be happy to share with committee.

Without this legislation, Wisconsin risks:

- A federally-mandated selection process for who gets to build transmission in Wisconsin, which would lead to inevitable delay in addressing customer needs and result in litigation (this delay typically adds a year to transmission being built);
- A loss of control over who builds transmission in the state – possibly for every project;
- A fragmented transmission system built to varying standards; and,
- A process with no credible support for the belief that costs will be reduced, nor that the system will be operated and maintained safer and more reliably.

Wisconsin has a safe, reliable, and cost-effective transmission system, and passing this legislation will ensure the state's ability to maintain and adapt this model in the future.

Thank you and I welcome your questions.

AMERICAN TRANSMISSION COMPANY®

Helping to keep the lights on,
businesses running
and communities strong®

January 26, 2022

Subject: Senate Bill 838/Assembly Bill 892

American Transmission Company (ATC) supports Senate Bill 838/Assembly Bill 892, as it ensures Wisconsin will preserve the state's right to control the expansion and operation of the grid to meet the needs of the state's customers and avoid uncertainty and delay created by the federal process to select entities to own and operate transmission infrastructure.

The Wisconsin Legislature enabled the creation of ATC in 1999, particularly to improve reliability of the state's grid. As the Legislature intended, our company operates these facilities as a single system, providing economies of scale and ensuring that the needs for this entire area are addressed holistically and customers throughout the footprint are served comparably. Our transmission system includes 9,928 miles of lines and 581 substations – 7,859 miles of lines and 495 substations are in Wisconsin.

Delivering on the Legislature's objective of forming ATC and to provide the benefits envisioned, since starting operations in 2001, we have built more than 1,236 miles of new lines and 39 substations in Wisconsin and also improved 530 of 746 segments of line and all our substations in the state. And working with utilities, regulators and other stakeholders in Wisconsin, ATC has improved reliability of its system that serves the state by reducing forced outages measured on an annual basis by 33% since 2002.

ATC is supporting Senate Bill 838/Assembly Bill 892 because it prevents a federal process established by the Federal Energy Regulatory Commission (FERC) from undermining Wisconsin's creation of ATC and the value it provides customers. FERC's Order No. 1000 in 2011 was a sweeping set of policies that included putting the Midcontinent Independent System Operator (MISO) in the role of selecting entities to pursue building and owning certain transmission projects in Wisconsin and 14 other states. ATC was an early supporter of FERC's efforts to ensure transmission is constructed to address customers' needs in the most cost-effective and efficient manner.

But Order No. 1000 – particularly, the federal process of selecting entities that construct certain transmission projects – failed to achieve its objectives. Notably, the federal selection process puts MISO – headquartered in Carmel, IN – in the position of selecting the developers that will pursue building and owning transmission in Wisconsin based on its judgement of how it believes an entity will perform. In MISO's process for selecting entities, estimated costs are reflected in only two of 23 factors considered and lumped in with the design of a project to account for only

30% of proposals' scores.[1] Thus, MISO mostly selects the entity that will pursue developing and owning a transmission project based on its judgment of an entity's ability to acquire right of way and land, obtain permits from the Public Service Commission of Wisconsin (PSCW) and other regulators, construct the project, and operate the facilities, among other factors.

Opponents of Senate Bill 838/Assembly Bill 892 claim that federal selection processes for transmission developers will reduce project costs, which stems from a report that was prepared for a merchant transmission developer.[2] However, the findings have been refuted.[3]

ATC actively manages and drives down project costs, which are capped and monitored by the PSCW. These efforts include competitively sourcing transmission equipment and the local workforce that construct our facilities and using such practices as challenging cost estimates from contractors with independent cost estimates. This has led to costs of completed projects commonly coming in under budget. In fact, over the past 10 years, ATC has completed 26 transmission projects that required PSCW approval. On average, the ultimate costs of these projects were 12% less than the budget ordered by the PSCW. And our overall cost of providing transmission service – comprising 10% of a customer's electricity bill – is reviewed annually with stakeholders.

Aside from the high degree of oversight that the PSCW has on the costs of transmission projects that are built in the state and ATC's cost management practices, there are other key reasons ATC believes passage of Senate Bill 838/Assembly Bill 892 is necessary now:

- With FERC's Order No. 1000 and the federal process of selecting the entities that construct certain transmission projects being commonly viewed as failing to meet their objectives, most of the states in MISO that surround Wisconsin – including Minnesota, Michigan,[4] and Iowa – have already enacted laws maintaining control over transmission development and ownership.[5]

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[1] MISO uses these criteria to evaluate bids for transmission lines, per Attachment FF Section VIII.E.1. of MISO's tariff: cost is combined with project design quality for 30% of a bid's score; project implementation, is weighted at 35%; operations and maintenance, is weighted at 30%; and transmission planning participation, is weighted at 5%. Also, see Exhibit 1 that is attached.

[2] See the Brattle Group's April 2019 "Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value", which was prepared for transmission developer LS Power, whose staff also contributed to the report (p. 2 of 88). The report is located at: https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf.

[3] See pp. 15, 19-20 of "Building New Transmission: Experience To-Date Does Not Support Expanding Solicitations" (June 2019) from Concentric Energy Advisors prepared for multiple transmission owners in response to Brattle's report. The report is located at: CEA_Order1000report_final.pdf. Concentric (p. iii) found: "The methodological approach underlying the Brattle Report's recommendation that policymakers should expand solicitations also is fundamentally flawed. As such, there is no credible support for the claim that current transmission processes limit customer savings, or that expansion of competition will yield meaningful additional savings."

[4] SB 103 went into effect Dec. 17, 2021.

[5] See Exhibit 2 that is attached. Indiana, North Dakota, and South Dakota also have passed legislation similar to Senate Bill 868/Assembly Bill 892. The Missouri legislature also is currently considering similar legislation – SB 1003/HB 1811.

- Given the direction of federal policy and aggressiveness of merchant developers, there is a risk that MISO's authority to select the entities that will pursue constructing and owning certain transmission projects will be expanded to all projects. Not only would this be greatly inefficient because of the number of facilities built annually to keep up with customers' needs[6], the federal selection process undermines the Legislature's work in establishing ATC by introducing the possibility of disparate developers constructing a hodgepodge of projects built to varying standards – potentially fragmenting the system as it was in the past, reintroducing duplication in efforts and associated costs and addressing system issues piecemeal.

- The federal selection process in MISO delays transmission projects from being put into service and addressing customers' needs such as solving a reliability problem or accessing less-expensive power. [7] Instead of ATC or another Wisconsin company being able to start working on a project in its footprint as soon as it is identified in the regional transmission plan, MISO would take an additional 305 to 408 days to select a developer.[8]

- As mentioned above, ATC has a history of collaborating with our Wisconsin stakeholders to address customers' needs to ensure the grid remains safe and reliable and cost-effectively delivers power, while employing the local Wisconsin workforce to construct and maintain this infrastructure. Enabling the federal selection process to determine which entity will pursue constructing and owning transmission facilities in ATC's footprint risks fragmenting the system with international and out-of-state merchant developers[9] without certainty they will provide the same level of service to customers. And it is important to note that Wisconsin customers will need to rely on the entity that constructs and operates a transmission facility for 40 years or longer, as this is the general life of this infrastructure.

- Senate Bill 838/Assembly Bill 892 retains a Wisconsin-focused approach to providing a grid to meet the state's needs at a time of great change in how electricity is generated[10] and used without adding uncertainty around the transmission owners that customers rely on. In fact, MISO is currently undertaking a multi-year planning effort to identify transmission projects needed in its footprint – including in Wisconsin – to accommodate the reliable transition of the grid towards more renewable generation.

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[6] There were 335 new transmission projects in MISO's regional plan in 2021, 21 of those in ATC's footprint.
[7] See slide 6 of MISO's March 9, 2021 testimony before the Michigan Senate Energy and Technology Committee (PowerPoint Presentation (michigan.gov)).
[8] See p. 27 of Concentric Energy Advisors' report for overview of length of developer selection processes.
[9] See list of MISO's Qualified Transmission Developers (https://cdn.misoenergy.org/MISO%20Qualified%20Transmission%20Developers%20List82330.pdf).
[10] For instance, there currently are 89 projects representing 12 GW of generation proposed for Wisconsin being evaluated in MISO's interconnection process. Also, large, base-load generators are being retired, such as Alliant Energy in February 2021 announcing it will retire the 1.1 GW coal-fired Columbia Energy Center generation plant by the end of 2024.

Exhibit 1

Evaluation Principles Applied (Certainty, Risk Mitigation, Cost, & Specificity)	Tariff Criteria		Tariff subcriteria	Categorization	Score
	Cost & Design	0%	Estimated Project Cost and Rigor	('Best', 'Better', 'Good', 'Acceptable', or 'Unacceptable')	0-30 pts.
			Estimated ATRR and Rigor		
			Facility Design and Rigor		
	Project Implementation	35%	Project Implementation Schedule	('Best', 'Better', 'Good', 'Acceptable', or 'Unacceptable')	0-35 pts.
			Project Management		
			Route and Site Evaluation		
			Right-of-Way and Land Acquisition		
			Engineering and Surveying		
			Material Procurement		
			Regulatory Permitting		
			Construction		
			Commissioning		
			Previous Experiences		
			Capital Resources and Financing Plan		
	O & M	30%	Local Balancing Authority	('Best', 'Better', 'Good', 'Acceptable', or 'Unacceptable')	0-30 pts.
			Real-Time Operations Mointoring and Control		
			Switching		
			Preventative/Predictive Maintenance		
			Spare Parts, Structures, & Equipment		
			Forced Outage Response		
			Emergency Repair & Testing		
			Major Facility Replacement Capabilities		
Planning Participation		5%	Transmission Solution Idea Submittal Form	Yes or No	0 or 5 pts.
				Total Score:	0-100 pts.

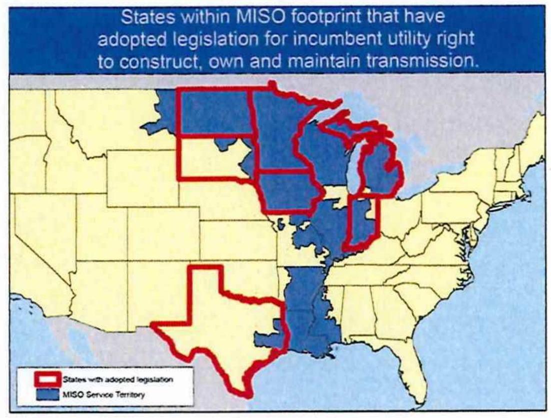
Figure 2-6: Proposal Evaluation Scorecard

Source: MISO's Dec. 20, 2016 Selection Report (p. 23) for the Duff-Coleman 345 kV project (https://cdn.misoenergy.org/Duff-Coleman%20EHV%20345kv%20Selection%20Report82339.pdf)

Maintain Wisconsin Control Over Transmission

WHAT AB892 | SB838 DOES

MAINTAINS STATE CONTROL



- Solidifies that Wisconsin, *like the majority of other states in the MISO region*, will continue to control the reliability of the grid in the state by preventing fragmentation and maintaining control over its expansion and operation to meet the needs of customers in our state.
- Retains the Wisconsin regulatory oversight and approval process without adding additional federal regulatory hurdles and bureaucracy.

PRESERVES CURRENT PSCW's COST CONTROLS & OVERSIGHT

- Over the past 10 years, the current PSCW process has led to ATC completing 24 of its 26 transmission projects within the PSC-ordered budget. On average, projects went into service **12% less** than the budget ordered by the PSCW, a total of over $220 million under budget.
- Retains the Public Service Commission of Wisconsin (PSCW) as the lead entity to maintain oversight of the project, including necessity of the transmission line, project budget, and control of the costs.
- Maintains the collaborative and transparent development process for the state's transmission operators for projects being developed across regions. In Wisconsin's current environment, transmission operators can collaborate to create the most cost-effective and reliable project.
- Current PSCW processes have led to transmission owners saving ratepayers over $39 million on Badger Coulee, and almost another $60 million on North Appleton – Morgan.

WHY AB892 | SB838 IS NEEDED

PREVENTS FRAGMENTATION OF WISCONSIN'S TRANSMISSION SYSTEM

- The federal control to determine which entity will construct and own transmission facilities in Wisconsin risks fragmenting the system with international and out-of-state merchant developers without certainty they will provide any savings or the same level of service to customers.
- The federal control of transmission undermines the Legislature's work in increasing reliability and introduces the possibility of disparate developers constructing a hodgepodge of projects built to varying standards – potentially fragmenting the system as it was in the past.

AVOID DELAYS FOR NEEDED TRANSMISSION UPGRADES

- The proposed federal selection process will likely delay transmission projects from being put into service and addressing customers' needs.
- Instead of an existing Wisconsin company being able to start working on a project in its footprint as soon as it is identified in the regional transmission plan, MISO would take an additional 10-15 months to select a developer.

MINIMIZES UNCERTAINTY

- A 2019 Concentric Report1 suggested the potential reliability implications presented by a federal selection process. The study indicates that the entities claiming to build projects "cheaper" do so by agreeing to "cost caps" on routine operations & maintenance (O&M), thereby potentially neglecting critical O&M investments. Ultimately, this threatens reliability for all customers

WHAT AB892 | SB838 DOESN'T DO

DOESN'T LEAD TO HIGHER COSTS

- In MISO's process for selecting entities, estimated costs are reflected in only two of 23 factors considered and lumped in with the design of a project to account for only 30% of proposals' scores.
- Claims of the federal process reducing costs for transmission lines are not credible. The claimed savings are based on a report that was prepared for a merchant transmission developer and have been refuted by subsequent industry studies.

DOESN'T ELIMINATE COMPETITIVE PRICING

- The state's transmission providers currently rely upon an independent process to develop project cost estimates and rely on a competitive process to select the contractors that will ultimately build the PSCW authorized lines; as well as actively managing costs throughout the construction cycle – savings that get passed along to ratepayers.

DOESN'T ELIMINATE INCENTIVES TO DRIVE DOWN COSTS

- Transmission owners have always, and will continue, to actively drive down project costs. For example, over the past 10 years, ATC has completed 26 transmission projects that on average were 12% less than the budget ordered by the PSCW.
- Transmission owners saved ratepayers over $39 million on Badger Coulee, and almost another $60 million on North Appleton – Morgan.

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[1] https://ceadvisors.com/wp-content/uploads/2019/06/CEA_Order1000report_final.pdf (Page 17)

BUILDING NEW TRANSMISSION

EXPERIENCE TO-DATE DOES NOT SUPPORT EXPANDING SOLICITATIONS

PREPARED BY:

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PREPARED FOR:

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June 2019

CEADVISORS.COM

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EXECUTIVE SUMMARY

The value of electric transmission is significant and well documented. Transmission infrastructure provides customers with a reliable and resilient flow of power, integrates diverse and cost-effective energy resources, enables production cost savings, reduces amounts and costs of planning reserve margins, and increases competition among supply resources for the benefit of customers.[1] Incumbent transmission owners ("TOs") have made the majority of the transmission investments in the U.S. and, more recently, a number of transmission projects have been subject to competitive solicitation processes ("solicitations") and awarded to non-incumbent transmission developers. Some argue that these solicitations should be expanded. Proponents of such an expansion, including the Brattle Group in an April 2019 Report ("Brattle Report" or "report"), assert that expanding the scope of such solicitations will yield significant cost savings.[2]

The savings that will result from significantly expanding solicitations for new transmission projects, as claimed in the Brattle Report, are based in part on the assumption that transmission projects developed by incumbent TOs, as opposed to those selected through a solicitation, will experience significant cost escalations with final project costs exceeding initial estimates by 18-70%.[3] This assumption is false and inconsistent with the empirical evidence. Concentric found that incumbent TOs in independent system operators ("ISOs") and regional transmission organizations ("RTOs") that track project costs develop reasonable initial cost estimates, with final and/or updated project cost estimates falling between -2.9% and 7.0% of initial estimates.

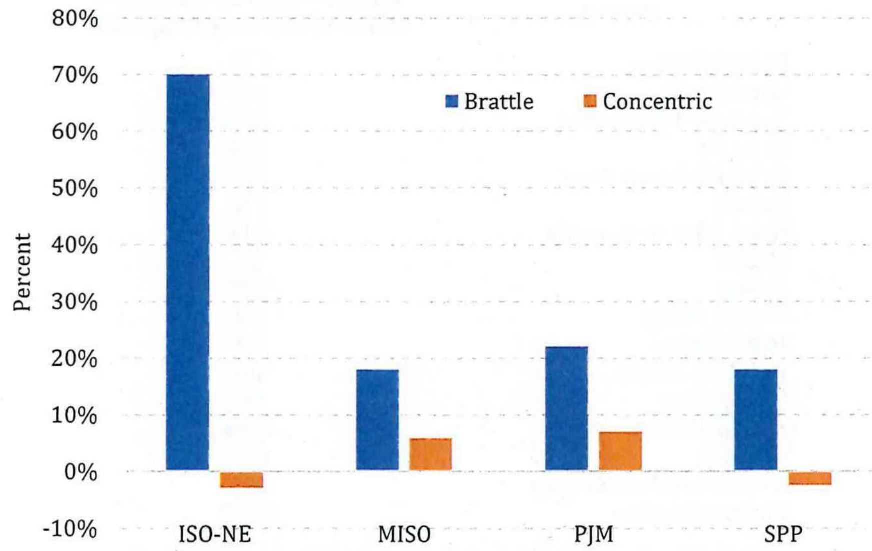
The methodological approach underlying the Brattle Report's recommendation that policymakers should expand solicitations also is fundamentally flawed. As such, there is no credible support for the claim that current transmission processes limit customer savings, or that expansion of competition will yield meaningful additional savings. The Brattle Report inappropriately compares different types of project cost estimates, fails to account for differences in scope between project cost estimates, and uses a limited and unrepresentative sample size of incumbent TO projects to produce its average historical cost escalation estimates, which are significantly overstated. Figure E1 below compares Concentric's estimates to the Brattle Report.

1 See e.g., Edison Electric Institute, Smarter Energy Infrastructure: The Critical Role and Value of Electric Transmission (March 2019).

2 The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission*, (April 2019). ("Brattle Report" or "report").

3 Brattle Report p. 41, Figure 18, column 5.

Figure E1: Comparison of Concentric and Brattle Historical Cost Escalation Estimates for ISOs/RTOs with Cost Tracking Databases



Importantly, of the 15 projects that the Brattle Report used to calculate its cost savings estimates, the final cost of the majority of the projects is currently unknown. Although many of the winning bids have cost caps, many of the cost caps have exclusions and exceptions that permit the project's final cost to exceed the cost submitted in the initial winning bid. Furthermore, the cost cap exclusions for some projects apply to the project cost components with the highest risk of cost increases (e.g., routing changes). Final project costs that exceed the costs in the winning bid could erode a significant amount of the savings claimed in the Brattle Report.

While the Brattle Report acknowledges some of these flaws,[4] it nonetheless applies its estimate of cost savings to a much broader (and undefined) set of transmission projects and erroneously concludes that significant savings could be achieved by expanding solicitations to cover a larger portion of U.S. transmission investment, including investments made in regions that do not currently conduct solicitations for transmission projects.[5]

Concentric also reviewed the implementation details of the 15 solicitations upon which the Brattle Report's savings estimates are based and found that the solicitations were time and resource intensive. One of the most significant expenditures was time. For each solicitation, Table E-1 shows the time between the date the project need was first identified and final ISO/RTO Board approval of the winning bidder. The time involved to conduct solicitations with more than one bidder ranged from 113 days to 1,498 days.

[4] Brattle Report, p. 39.
[5] Brattle Report, p. 13.

Table E-1: Time involved in transmission solicitations

Project	Days Between Identification and ISO/RTO Board Approval
Imperial Valley	113
Gates-Gregg	231
Sycamore Penasquitos	349
Suncrest	174
Delany Colorado River	359
Estrella	238
Harry Allen to Eldorado	544
Miguel†	55
Spring	238
Wheeler Ridge	238
Duff Coleman	385
Hartburg-Sabine	361
Walkemeyer	448
Artificial Island	1,498
AP South	893
NY Western Public Policy	820
AC Transmission	1,208

† The Miguel solicitation had a single bidder – San Diego Gas & Electric. See Table 12 for more details about the timeline of each solicitation.

Time is an important consideration because delayed project development denies customers the benefits of transmission investments, such as reduced congestion costs or increased reliability. Significantly expanding solicitations would also conflict with Federal Energy Regulatory Commission ("FERC" or "Commission") precedent established in the Order No. 1000 proceeding. Furthermore, the time, money and resources these solicitations would require should not be overlooked because such costs could make conducting a solicitation for certain types of projects (e.g., upgrades) uneconomic. Concentric reviewed the claims in the Brattle Report as well as additional information about the solicitations held to date. Based on this review, we find the Brattle Report's claims that the solicitations held to date have produced significant savings to be baseless. Claims that expanding the solicitations would yield up to $9 billion in savings[6] are without merit and should not be relied upon to justify any expansion of solicitations for new transmission projects.

6 Brattle Report, p. 13

1. Introduction

In 2011, the Federal Energy Regulatory Commission ("FERC" or "Commission") issued Order No. 1000. Among other things, Order No. 1000 requires jurisdictional public utility transmission providers to produce a regional plan to meet the region's transmission needs more efficiently or cost-effectively.[7] The six FERC-jurisdictional independent system operators ("ISOs") and regional transmission organizations ("RTOs") that are required to comply with FERC Order No. 1000 chose to select certain new types of transmission projects through solicitation processes.[8]

More recently, proponents of expanded solicitations for transmission, including the Brattle Group in a recent report ("Brattle Report" or "report") have advocated that transmission solicitations should be significantly expanded because doing so will purportedly reduce customer costs by up to 30%.[9]

Based on Concentric's review, the savings claimed in the Brattle Report are inaccurate and do not provide a basis to expand the scope of solicitations in FERC-jurisdictional ISOs/RTOs or anywhere else. First, it is not possible to estimate potential savings from the solicitations held to-date because the final costs of most projects are not known and the cost caps in some of the winning bids are not guaranteed to contain final costs. Second, the savings claimed in the Brattle Report are without merit. The report's lower bound savings estimates for the solicitations are flawed because Brattle uses an inappropriate benchmark to estimate savings from those solicitations. The upper bound savings estimates are also methodologically flawed and rely on over-stated "cost overrun" estimates for incumbent Transmission Owners ("incumbent TOs"). Concentric's review of publicly available ISO/RTO cost tracking data suggests that incumbent TOs experience fairly modest cost changes, which are negative in some ISOs/RTOs, with final or updated project cost estimates varying from initial cost estimates by between -2.9% to 7.0%, in the ISOs/RTOs with publicly available cost tracking databases.[10] Given the risks inherent with transmission development, in our view incumbent TOs have demonstrated an ability to develop reasonably accurate cost estimates that appropriately account for project risks.

The remainder of this report is organized as follows: Section 2 discusses the Brattle Report's claims that the transmission projects developed by incumbent TOs experience significant cost escalations and presents Concentric's analysis of the same data that yields different results. Section 3 examines Brattle's claims that the solicitations held to-date produced significant cost savings. Section 4 explains that transmission solicitations

7 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 136 FERC ¶ 61,051 (July 21, 2011) ("Order No. 1000").

8 Non-ISO/RTO regions that are FERC-jurisdictional are also required to comply with Order No. 1000 reforms, however, these non-ISO/RTO regions do not conduct solicitations for new transmission projects as part of their regional transmission planning process and are thus not discussed in this report.

9 Brattle Report, p. 13, Figure 4.

10 The ISO/RTOs with cost tracking database are: ISO New England, Inc. ("ISO-NE"); Midcontinent Independent System Operator ("MISO"); Southwest Power Pool ("SPP"); and PJM Interconnection ("PJM").

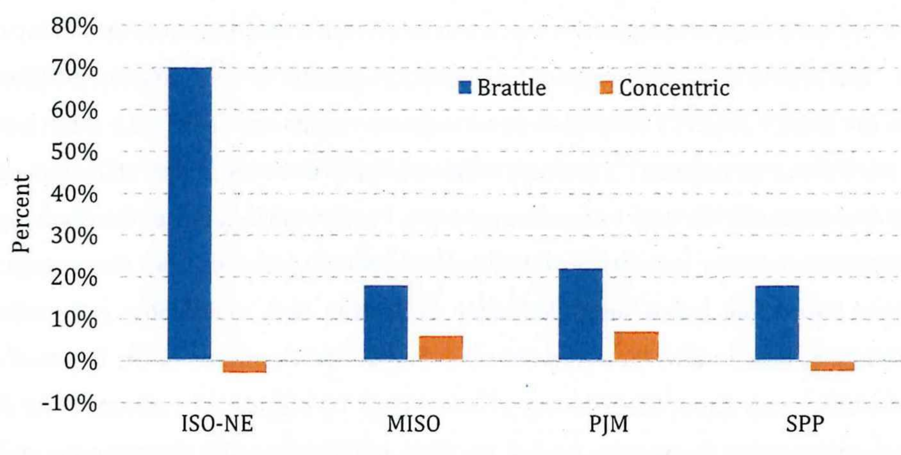
are time and resource intensive, a consideration that must be weighed before expanding the scope of such solicitations. Section 5 explains that Brattle's recommendation to expand the scope of solicitations would be inconsistent with the Commission's reliability and resilience goals and would require the Commission to revisit prior findings in Order No. 1000 and in other orders. Section 6 summarizes the report's findings and concludes that, based on Concentric's review of the evidence to-date and the claims made in the Brattle Report, there is no basis to expand the scope of transmission projects that are selected through solicitations at this time.

2. Incumbent Transmission Owner Initial Cost Estimates are Accurate

The Brattle Report claims that transmission investments that are not selected through a solicitation, but instead developed by incumbent TOs in ISOs/RTOs, experience cost escalations ranging from a low of 18% in SPP and MISO to a high of 70% in ISO-NE.[11]

Concentric first performed its own analysis using the same data relied upon in the Brattle Report to assess the accuracy and reasonableness of the claims about incumbent TOs. Where possible, Concentric also analyzed publicly available ISO/RTO transmission project tracking databases that provide more comprehensive information of initial and final and/or updated project cost estimates to produce our own estimates. Figure 1 and Table 1 compare the Brattle Report and Concentric estimates of the extent to which incumbent TO initial transmission project cost estimates exceed final costs and/or updated cost estimates. As described further below, Concentric's analysis shows that the difference between the initial and final and/or updated cost estimates of incumbent TO projects is fairly modest or negative, ranging from -2.9% to 7.0% for four of the five ISOs/RTOs reviewed, and less than half of what the Brattle Report estimates for the fifth ISO, California ISO ("CAISO").

Figure 1: Comparison of Concentric and Brattle Historical Cost Escalation Estimates for ISOs/RTOs with Cost Tracking Databases



11 Brattle Report, Figures 21, 22, 24 and 25.

Table 1: Comparison of Concentric and Brattle Incumbent TO Historical Cost Escalation Estimates

ISO/RTO	Brattle	Concentric
CAISO*	41%	PG&E: 6.1 to18.8% SDG&E: 5.9%
ISO-NE	70%	-2.9%
MISO	18%	5.9 %
NYISO	n/a	n/a
PJM	22%	7.0%
SPP	18%	-2.4%

Source: Brattle estimates are from Brattle Report, p. 41, Figure 18, column 5. Concentric estimates are discussed herein. CAISO does not have a cost tracking database so Concentric's estimates for PG&E and SDG&E projects are not representative of either CAISO as a whole or of these TOs' full portfolio of projects. The CAISO estimate is only provided for purposes of comparison with the Brattle Report's CAISO estimate.

The methods used in the Brattle Report to estimate the "average historical cost escalations" of incumbent TO projects are flawed and produce inaccurate and misleading results. The Brattle Report's "average historical cost escalation" estimates are based on a limited sample of projects that are not representative of the full portfolio of incumbent TO projects in each ISO/RTO. As discussed further below, for ISO-NE, SPP, and CAISO, the Brattle Report compared early high-level estimates that were made before the scope of the project was finalized, which is a meaningless comparison that is not informative about the accuracy of incumbent TO initial cost estimates. The Brattle Report also ignored a significant number of transmission projects in ISO-NE, PJM, and SPP. Thus, the Brattle Report's estimated cost escalation results are based on a small sample that did not reflect the full portfolio of incumbent TO projects in these ISOs/RTOs or the ability of incumbent TOs to produce accurate initial cost estimates for their respective projects. Furthermore, many of the planning processes were intentionally designed to foster stakeholder involvement and collaboration, with early-stage, conceptual cost estimates refined over time based on stakeholder discussion and, eventually, proceedings before state regulatory authorities. In our view, the estimates of historical cost escalation in the Brattle Report should not be used to draw inferences about the accuracy of incumbent TO initial cost estimates. As discussed further below, it is more appropriate to examine the full portfolio of incumbent TO transmission projects in order to draw conclusions about the accuracy of initial cost estimates.

Using a broader sample, Concentric finds that the difference between initial cost estimates and final or updated project cost estimates are quite modest (see Table 1), and in some cases, final or updated costs are below initial cost estimates. As discussed further in Section 3, the Brattle Report used these flawed and overstated "historical cost escalations" to estimate that solicitations for new transmission projects will save 22% to 67% compared to designating the incumbent TO as the project developer.[12]

[12] Brattle Report, p. 43, Figure 19.

Before discussing our analysis of incumbent TO cost estimates, it is important to provide context for the nature of transmission development. 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.

While the nomenclature of these estimates differs by ISO/RTO, the estimates broadly fall into the three stages: conceptual, planning, and engineering/construction. The development of a transmission project's initial cost estimate takes place early in the planning process. For example, high-level conceptual and planning estimates are often used to compare alternative solutions and are more conceptual in nature. Because these estimates are based on conceptual plans or proposals rather than specific projects, they do not reflect detailed design or engineering considerations. As the project proceeds through its development cycle, updated estimates based on the latest information are developed and released.

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.[13] For example, equipment cost estimates become more accurate once the developer learns more about the specifics of the equipment needed and obtains supplier quotes; and this information would be included in an estimate produced during the engineering and/or construction stage of development. For greenfield projects, the precision of the cost estimate increases as information about the transmission line's route and design is refined during the permitting process, which enables the developer to produce more accurate estimates of construction and permitting costs. Such uncertainties are typically beyond the developer's control – regardless of whether or not the developer is an incumbent. Given these uncertainties, transmission project developers frequently include contingencies in their initial cost estimates. Accordingly, great care must be taken in comparing different types of project cost estimates because comparing two different cost estimates without understanding the nature of each estimate could result in a meaningless or uninformed comparison. As discussed further below, we believe many of the conclusions and estimates in the Brattle Report are based on such inappropriate comparisons.

The remainder of this Section identifies the flaws in the Brattle Report's comparisons of incumbent TO initial and final or updated project cost estimates in each ISO/RTO where such an analysis was possible. We then present our own analysis, which uses a broader sample of incumbent TO projects and, where appropriate, accounts for differences in the nature of the initial cost estimates, to assess the accuracy of incumbent TO initial project cost estimates. In our view, Concentric's estimates are more accurate than the Brattle Report estimates because they are based on a more complete portfolio of projects, and thus are more representative of average incumbent TO cost performance.

13 See Appendix B for more details.

The differences between incumbent TO initial and final and/or updated project cost estimates are noteworthy considering the iterative nature of estimating transmission project costs, which become more accurate over time as better information about the project becomes available. In an effort to be conservative and to be consistent with the Brattle approach, Concentric's estimates of how incumbent TOs' initial and final project costs compare do not adjust for inflation. Inflation accounts for some of the difference between initial and final cost estimates, so accounting for inflation would have reduced our estimates of historical cost escalations. Below we present our analysis of the accuracy of initial project cost estimates in ISO-NE, MISO, SPP, PJM, and CAISO.

2.1. ISO-NE

The Brattle Report claims that, on average, the actual costs for ISO-NE incumbent TO projects exceeded initial estimated costs by approximately 70%. The report only relied on 14 transmission projects that were developed by ISO-NE incumbent TOs, some proposed as early as 2002, to estimate the average historical cost escalation for all ISO-NE transmission projects. These 14 projects represent less than 2% of all projects placed in-service across New England since 2002. For 3 of the 14 projects, the Brattle Report relied on a publicly available cost tracking database and Concentric was able to validate the costs of these projects.[14] For the remaining 11 projects, the Brattle Report relied on a 2015 presentation.[15] Concentric examined these 11 projects and also conducted an analysis on the full portfolio of incumbent TO projects in ISO-NE using the ISO-NE project cost tracking database. Based on this broader and more representative sample of ISO-NE incumbent TO projects, Concentric found that final project costs in ISO-NE were actually 2.9% *below* initial estimates.

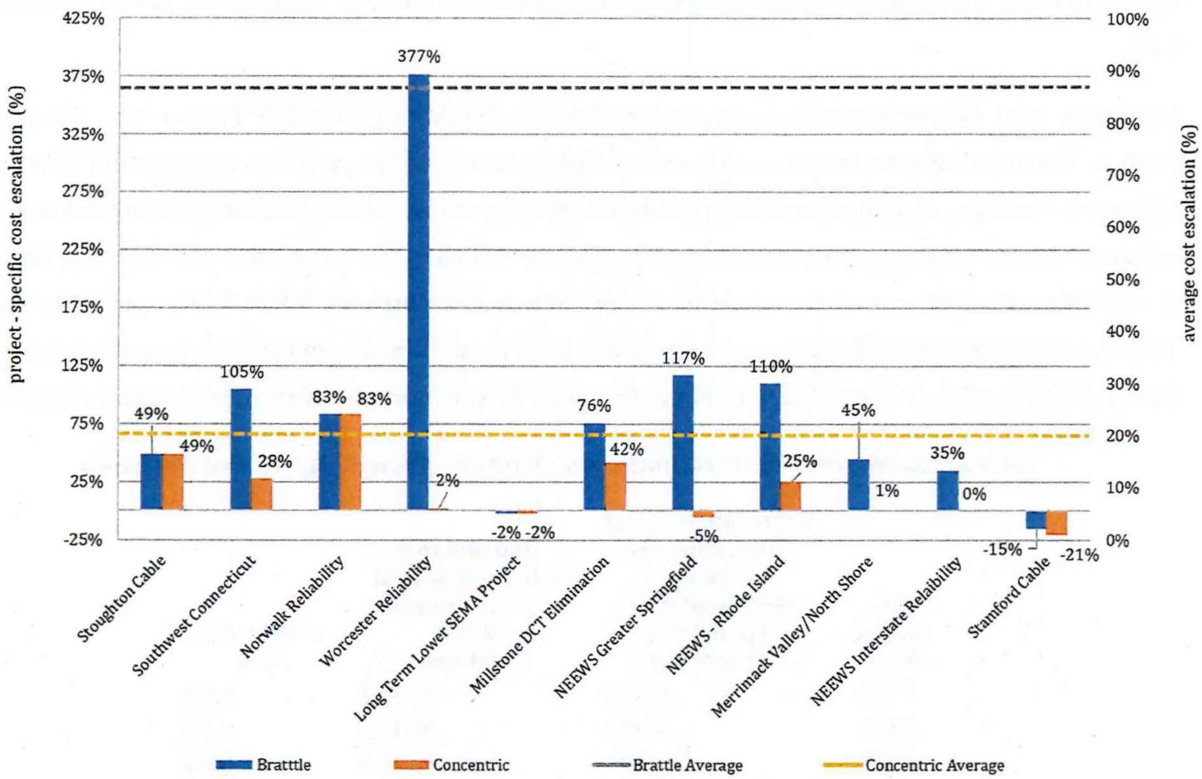
As a first step in assessing incumbent TO project costs in ISO-NE, Concentric reviewed the construction costs of 11 of the 14 transmission projects the Brattle Report based its 70% cost escalation estimate on. The Brattle Report used the initial cost estimate published by ISO-NE at the time the project was first proposed but *before* a scope was fully defined or detailed engineering performed for the project. As noted above, estimates that are developed early in the planning process are, by definition, high-level estimates that are based on a loosely defined scope. Concentric's analysis of the 11 projects used the same final project costs as the Brattle Report but a different and more appropriate initial cost estimate. For initial cost estimates, we used the estimated cost contained in the siting application of each project rather than the first estimates published (which were developed before key project decisions - such as overhead versus underground construction - were made). The cost estimate in the siting application reflects the project's actual scope, which is much better understood at the beginning of the siting/permitting phase. At this point in time, the incumbent TO developers have enough detail to more accurately estimate the cost of the proposed projects. Figure 2shows that if the project cost

14 Specifically, the Scobie-Tewksbury, Wakefield-Woburn, and Mystic Woburn projects, which the Brattle Report obtained initial and updated cost estimate data from the March 2018 RSP tracking database. *See* Brattle Report, p. 57, Figure 25.

15 NextEra Energy Transmission, Greater Boston Cost Comparison, January 2015.

estimate contained in the project siting application is used, final project costs for the 11 projects examined exceeded estimated costs by 18%, which is far less than the 70% estimate in the report. See Appendix A for more details about the analysis described in Figure 2.

Figure 2: Recalculation of Brattle's Cost Escalations with Corrected Cost Estimates



In our view, Concentric's comparison is much more meaningful and produces a more accurate cost variance estimate because the cost estimate in the siting application is much closer in scope to the final project, and more in-line with an estimate that would be provided as part of a solicitation. Thus, Concentric's analysis uses two estimates that are reasonably comparable, whereas the Brattle Report compares two figures that are not comparable in any useful or informative way. It warrants mention that ISO-NE processes have evolved since the 11 projects, some of which were initially proposed in 2002. ISO-NE incumbent TOs now use multiple cost estimates throughout the planning process that reflect varying degrees of scope definition at the time the estimates are developed.

In addition to inaccurately representing project "cost escalation", the sample of projects the Brattle Report used to estimate historical cost escalations does not constitute a representative sample of incumbent TO projects in ISO-NE. The 11 projects, many of which were complex greenfield projects, have a much higher escalation risk – regardless of who develops the project.

In an effort to develop a more representative estimate of cost escalation for incumbent TOs in ISO-NE, Concentric used a publicly available ISO-NE transmission cost tracking database that tracks most significant transmission projects in ISO-NE. ISO-NE's regional transmission planning document is called the Regional System Plan ("RSP"). The "RSP Project List" tracks cost information about reliability projects in the RSP (generally those with estimated costs above $5 million) and tracks how cost estimates for projects change over time.

Concentric used data on reliability upgrade projects from the March 2019 RSP Project list. We used the estimate from the time the incumbent TO received approval of its Proposed Plan Application ("PPA") as an initial cost estimate. At this point in time, the necessary components of a project are generally defined with a sufficient level of detail to yield a reasonably accurate cost estimate. For an updated cost estimate/final cost, as applicable, Concentric used the cost estimate available in the March 2019 RSP Project List. As shown in Table 2, comparing the initial and current (as of March 2019) cost estimate shows that, in aggregate, incumbent TOs in ISO-NE had final/updated cost estimates that were 2.9% below the initial cost estimates in the PPAs.

Table 2: ISO-NE Incumbent TO Initial and Final or Updated Project Cost Estimates

In-Service Year	Aggregated project cost estimates from Proposed Plan Application ($ million)	Updated cost estimates or final costs as of March 2019 ($ million)	Difference (%)
2011	$265.2	$248.2	-6.4%
2012	$410.2	$411.1	0.2%
2013	$1,230.2	$1,165.3	-5.3%
2014	$457.5	$440.6	-3.7%
2015	$751.4	$716.3	-4.7%
2016	$364.2	$377.1	3.6%
2017	$260.9	$271.0	3.9%
2018	$157.0	$153.8	-2.0%
Total	$3,896.7	$3,783.5	-2.9%

Notes: Table compares all reliability upgrade projects in service between 2010 and 2018 based on projects tracked in ISO-NE's March 2019 RSP Project List tracking database. Figures reported in nominal dollars for all projects with cost information on both the Proposed Application Plan estimate and an updated estimate or final project cost. The RSP Project list generally contains only projects with costs above $5 million.

Concentric's estimate is based on a sample of 150 projects - a much broader sample than the 11 projects reviewed in the Brattle Report - to estimate how ISO-NE incumbent TO initial cost estimates compare to updated or final project costs. The estimates in Table 2 are presented in nominal dollars (accounting for inflation would make the cost decrease even bigger), and are significantly below the 70% "cost escalation" estimate in the Brattle Report.

2.2. MISO

Brattle estimates that the costs of MISO's incumbent TO projects have increased by 18% for the 2015-2018 planning cycles. Because Concentric could not replicate the figures shown in Brattle's Figure 21, we are unable to review Brattle's methodology. However, Concentric reviewed the same publicly available transmission project cost data relied upon by Brattle, which shows that cost escalations ranged from 0.5% to 7%, far lower than the Brattle results.

Table 3: MISO Facility Cost Change Estimates

	Initial ($million)		In-Service ($million)		% Change
MTEP 2014	$	9,085	$	9,747	7.3%
MTEP 2015		7,292		7,615	4.4%
MTEP 2016		6,304		6,675	5.9%
MTEP 2017		478		480	0.5%
Total	**$**	**23,159**	**$**	**24,517**	**5.9%**

Concentric reviewed the change between initial estimates and in-service costs for projects approved in the 2014-2017 MISO Transmission Expansion Plans ("MTEP"). This analysis is discussed further in Appendix A. In total, these projects have experienced a 6% cost escalation.

2.3. SPP

Brattle estimates that the costs of SPP's incumbent TO projects developed from 2009 through 2019 experienced cost escalations of 18%. Concentric determined that this estimate is significantly overstated. Table 4 shows the Brattle Report's cost escalation estimates for Balanced Portfolio Projects, Priority Projects, and ITP Portfolio Projects in SPP. In total, Brattle claims that costs have increased from $2,028 million to $2,391 million (without controlling for inflation), for a total cost escalation of 18%. However, upon closer review of each category of projects using the same data sources, Concentric determined that these projects actually experienced a "cost escalation" of negative 2%.

Table 4: SPP Incumbent TO Project Cost Estimates

SPP Portfolio	Brattle Initial TO Cost Estimate ($ million)	CEA Initial TO Cost Estimate ($ million)	Latest Cost Estimate ($ million)	Brattle Estimated Cost Escalation	CEA Estimated Cost Escalation	# of Projects
Balanced Portfolio	$691	$832	$831	20%	0%	
Priority Projects	$1,145	$1,416	$1,349	18%	-5%	
ITP Portfolio Projects with Final Cost Estimates (2012 to 2017)	$192	n/a	$211	10%		42
ITP Portfolio Projects Listed as Complete (2012 to 2017)	n/a	$1,349	$1,330	n/a	-1%	150
Brattle Total Comparison	$2,028	$2,249	$2,391	18%	n/a	
Concentric Total Comparison	n/a	$3,597	$3,510	n/a	-2%	

As discussed further in Appendix A, the initial estimates used in the Brattle Report for the Balanced Portfolio and Priority Projects were based on initial project scopes that were revised at the direction of SPP. As such, most of the escalation the Brattle Report estimates for these projects is due to a change in scope rather than action or lack of cost discipline on the part of the incumbent TO developers. Thus, the Brattle Report estimates of historical cost escalations in SPP and ISO-NE are flawed for similar reasons – they inappropriately compare different types of project cost estimates and in both cases, compare projects of different scopes.

2.4. PJM

The Brattle Report estimates that the costs of PJM's incumbent TO projects experienced escalations of 22% relative to initial cost estimates.[16] To produce this estimate, Brattle appears to use data selectively that significantly underrepresents the PJM projects with cost tracking data. To produce an estimate for PJM, Concentric expanded the sample of transmission projects by including all projects that had both initial and updated cost information in the PJM cost tracking database and concluded that the updated cost estimates of PJM TOs only exceeded initial estimates by 7.0%.

Concentric first attempted to recreate the PJM estimate in Figure 24 of the Brattle Report, which analyzed Baseline Reliability and Network Upgrade projects in service or under construction during the 2014-2017 period. Concentric analyzed the data sources cited in the Brattle Report to support this estimate but was unable to reproduce the estimate. However, based on our review which is summarized in Table 5, it is clear that the Brattle Report estimate only included a subset of the Network Upgrade and Baseline Reliability projects. As shown in Table 5, the Brattle Report estimate included $4,520 million in projects while the Concentric estimate, which is based on all Network Upgrade and Baseline Reliability projects for which initial and updated cost

16 Brattle Report, Figure 24, p. 56.

information is available, includes $12,999 million in projects. For unknown reasons, the Brattle Report's estimate for PJM cost escalation excluded about two-thirds of the incumbent TO Baseline Reliability and Network Upgrade projects, despite the fact that information was available for those projects.[17] Concentric's analysis of the full sample of Baseline Reliability and Network Upgrade projects (shown in Table 5) found that updated cost estimates for Baseline Reliability and Network Upgrades were 5.2% above initial estimates on average, which is a quarter of Brattle's 22% "cost escalation" estimate.

Table 5: PJM Initial and Latest Project Costs Estimates for Baseline Reliability and Network Upgrade Projects

	Initial Estimate ($ million)	Latest Estimate ($ million)	Latest vs. Initial Estimate (%)
Brattle Report Estimates			
2014	822	971	18%
2015	1,722	2,124	23%
2016	768	940	22%
2017	382	485	27%
2014-17 total	3,694	4,520	22%
Concentric Estimates			
2014	2,818	3,075	9.1%
2015	4,331	4,545	4.9%
2016	3,471	3,581	3.2%
2017	1,732	1,798	3.8%
2014-17 total	12,352	12,999	5.2%

Notes: Source of Brattle Report Estimates: Brattle Report, p. 56, Figure 24. For Baseline Reliability Projects, initial cost estimates are from the PJM Transmission Cost Allocation Database (May 1, 2019 version) and latest cost estimates are from the Construction Status Database. For Network Upgrades, the initial cost estimates are from the 2014-2017 TEAC Whitepapers and the latest cost estimates are from the Construction Status Database. Project years are based on the Display Service Date from the Transmission Cost Allocation Database. The above figures only reflect projects for which both initial and latest cost estimate data are available and are not adjusted for inflation.

The Brattle Report estimates for PJM excluded Supplemental Projects, which constitutes the third category of transmission projects in PJM. In an effort to use a larger and more representative sample of incumbent TO projects in PJM, Concentric performed an analysis that also includes Supplemental Projects, which increases the sample of projects (as measured by latest project cost estimates) by 44%.

17 According to the notes of Table 15 of the Brattle Report, Brattle excluded the 72% of projects where the initial and latest cost estimates were the same, stating that "it is unclear whether these reported latest estimated costs in PJM's database are appropriately reflective of actual cost changes in Projects' cost estimates, therefore they have been excluded" from the Brattle Report estimate. However, we found no documentation or basis to exclude these data.

Table 6: PJM Initial and Latest Project Costs Estimates for Baseline, Network Upgrade, and Supplemental Projects

	Initial Estimate ($ million)	Latest Estimate ($ million)	Latest vs. Initial Estimate (%)
2014	3,621	4,023	11.1%
2015	5,361	5,746	7.2%
2016	4,685	4,899	4.6%
2017	3,858	4,087	5.9%
2014-17 total	**17,525**	**18,755**	**7.0%**

Notes: see notes for Table 5 for the source of the Baseline and Network Upgrade project cost figures. Supplemental Project initial and updated project costs are from the PJM Transmission Cost Allocation Database (May 1, 2019 version).

Based on this expanded sample size, shown in Table 6, updated project cost estimates for PJM incumbent TOs exceeded initial cost estimates by 7.0%, significantly below the 22% estimate in the Brattle Report.

2.5. CAISO

Unlike ISO-NE, MISO, PJM, and SPP, CAISO does not publish a centralized and publicly available transmission project cost tracking database. (Neither does the New York ISO ("NYISO").) As such, it is not possible to conduct a robust and accurate analysis of the initial and final and/or updated project costs for the full portfolio of transmission projects in CAISO or NYISO. Nevertheless, Concentric conducted an analysis to assess the reasonableness and accuracy of the Brattle Report estimates for CAISO.

The Brattle Report claims, based on an analysis of 10 projects,[18] that incumbent TOs in CAISO have experienced a 41% cost escalation on average.[19] Concentric reviewed the methodology Brattle used to estimate cost escalation in CAISO and determined that, much like the report's estimates for ISO-NE, the CAISO cost escalation estimate is inaccurate because it is based on a small and unrepresentative sample of projects. Concentric's analysis, described further in Appendix A, demonstrates that the limited sample that Brattle used to calculate its estimate should not be used to draw inferences about incumbent TO cost escalations in CAISO as a whole.

Given the lack of data, Concentric cannot confidently perform an analysis of the accuracy of CAISO incumbent TO initial estimates by comparing them to final project costs. However, Concentric found that analyzing a larger sample of projects based on information that was available in the FERC dockets cited in the report, casts doubt on the Brattle Report's estimates and suggests that CAISO incumbent TOs do not experience an average cost escalation of 41% as the report claims. Table 7 demonstrates the implication of expanding the sample to include all of the projects for which initial and final project cost information is available. Expanding this sample

[18] The Brattle Report analyzed 7 PG&E projects and 3 SDG&E projects. See e.g., Brattle Report, Figure 23.
[19] Brattle Report, Figure 23, p. 55.

reduces the average cost escalation for PG&E from 52.7% to between 6.1% and 18.8% and increases the cost escalation estimate for SGD&E from 2.3% to 5.9%.

Table 7: Concentric Review of Brattle Report Historical Cost Escalation Estimate for CAISO

	Number of Projects	Initial Estimate ($)	Final Cost ($)	Final Cost - Initial (%)
Pacific Gas & Electric				
Full available sample	55	$1,534.7-$1,718.1	$1,823.5	6.1-18.8%
Brattle Sample	7	$668.6	$1,021.1	52.7%
San Diego Gas & Electric				
Full available sample	17	$782.4	$828.9	5.9%
Brattle Report sample	3	$199.1	$203.7	2.3%

Note: PG&E initial estimates were provided as a range to CPUC in Docket No. EL17-45-000 so the initial cost estimates are also provided as a range for these projects. For projects in Docket No. EL16-2330, the initial estimates were those PG&E submitted to CAISO, and not the high range of the "CAISO estimate" referenced in Figure 23 of the Brattle Report.
SDG&E projects: *California Parties v. Pacific Gas and Electric Co.*, Docket No. EL17-45-000, Exhibit No 3 - SDG&E Response to CPUC Data Request, p. 7 (filed Feb. 2, 2017). Information provided for projects completed between January 2014 and November 2016.

The 41% escalation estimate for CAISO in the Brattle Report does not include any Southern California Edison projects despite the fact that it is the second largest incumbent TO in CAISO. Taken as a whole, Concentric found that the Brattle Report estimate for CAISO was not representative of the full portfolio of incumbent TO projects and inexplicably excluded certain transmission projects.

In conclusion, Concentric found the Brattle Report claims of 18% to 70% cost escalations in the ISOs/RTOs we reviewed to be inaccurate. After conducting a thorough review of publicly available information, we found a fairly modest margin, which is negative in some ISOs/RTOs, between incumbent TO initial project estimates and final project costs. As such, the Brattle Report estimates of incumbent TO cost escalations should not be used to draw inferences about initial and final transmission project costs in ISO-NE, MISO, SPP, PJM, or CAISO.

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 incumbent ownership and management of transmission systems. These benefits represent possible opportunity costs of competitive solicitations, which must be considered in addition to the direct costs, benefits, and uncertainties of the solicitations held to date.

3. Benefits of Transmission Solicitations are Unknown

Concentric reviewed the methodology used in the Brattle Report to estimate the savings from 15 solicitations (see Table 8).[20] As an initial matter, it is not yet possible to determine the cost impacts of these solicitations because only one[21] of the projects selected through the solicitations is in service. Of the remaining 14, two have been canceled,[22] and the rest are in various degrees of development, as the Brattle Report notes.[23] In addition, the methods used in the Brattle Report to estimate savings from the 15 solicitations were flawed. As such, the final costs of the majority of the projects selected in these solicitations are unknown and unknowable at this time, and any resulting savings are also unknown.

MISO and NYISO have each held two solicitations, SPP has held one, and ISO-NE has not held any, although ISO-NE plans to hold a solicitation in the near future.[24] However, Massachusetts, a state within the ISO-NE footprint, issued a request for proposals ("RFP") for hydroelectric power or other clean energy and the transmission capacity to deliver it, and selected a developer in 2018.[25] Prior to this solicitation, Massachusetts, Connecticut, and Rhode Island jointly conducted the Clean Energy RFP that included options for new transmission. These solicitations took place outside of ISO-NE's regional transmission planning process.

Table 8: Transmission Solicitations Through ISO/RTO Regional Planning Processes as of April 2019

ISO/RTO	Number of Solicitations	Solicitations Included in Brattle Savings Estimates
CAISO	10	10
PJM	136	1
MISO	2	2
NYISO	2	1
SPP	1	1
ISO-NE	0	n/a

Source: Brattle Report, Figures 10-14 and Table 6. Notes: Although Brattle estimates savings for 10 CAISO solicitations, it only includes 9 of these in its Figure 19 because the Gates Gregg project was delayed. In addition, Brattle only estimates the savings from solicitations awarded to non-incumbents, and therefore ignores solicitations in PJM.

As noted above, the methods used in the Brattle Report to estimate savings from the 15 solicitations were flawed. First, Brattle used inappropriate benchmarks to estimate the lower bound of the potential savings.

20 Brattle Report, p. 28, Figure 10. Note that although Figure 10 references the AP South project in PJM and the Western NY project in NYISO, it did not rely on these solicitations in its analysis because both solicitations were won by incumbents. Additionally, the AC Transmission project had two segments (A and B) but NYISO sought proposals through a single solicitation.

21 SDG&E completed construction of the Sycamore-Peñasquitos project in August 2018. See e.g., https://www.cpuc.ca.gov/Environment/info/panoramaenv/Sycamore_Penasquitos/index.html

22 The Walkemeyer project in SPP was canceled and CAISO delayed the Gates Gregg project indefinitely.

23 Brattle Report, p. 39. For example, the report states "[w]hile many of the winning proposals include cost caps or cost control measures, the completed costs of these projects are not yet known and may exceed the selected projects' offer prices."

24 ISO-NE anticipates conducting a solicitation for a transmission project to meet reliability needs in the Boston Area later this year. ISO-NE previously considered holding a solicitation for the Keene Road area but determined after performing a cost-benefit analysis that it was not beneficial to do so.

25 *See e.g.*, New England Clean Energy Connect (https://www.necleanenergyconnect.org/project-overview). The state of Maine granted this project a CPCN in April 2019. *See* https://www.necleanenergyconnect.org/necec-milestones.

Second, the report used the overstated incumbent TO "average historical cost escalation" estimates discussed in Section 2 to estimate the upper bound of the potential savings. With these flaws, the Brattle Report's estimated savings from the solicitations should not be relied upon for decision-making purposes.

The remainder of this section discusses Concentric's review of the Brattle Report's claims about the cost savings from the solicitations. Section 3.1 discusses the fact that the final costs of the projects are not known for the majority of the projects and describes the exclusions to the cost caps contained in some of the winning bids. Section 3.2 describes Concentric's review of claims in the Brattle Report that solicitations saved between 18% and 67%. We identified significant issues with these savings estimates. Section 3.2.1 describes the inappropriate benchmarks Brattle used to calculate its lower bound of savings estimates and Section 3.2.2 explains why the upper bound savings estimates are methodologically flawed.

3.1. Final Project Costs are Unknown

Of the 15 projects that Brattle uses to calculate its cost savings estimates, the final costs of the majority of the projects is unknown, so it is impossible at this time to determine the actual cost escalations, if any, associated with the majority of the projects awarded through the solicitations. Nevertheless, Brattle claims without any evidence that "on average [competitively-developed] projects may not escalate as much as other regional transmission projects have historically" as a result of bidder due diligence and cost caps. This claim is speculative given the lack of final cost data and cost cap exclusions described below. Furthermore, as shown in Section 2, incumbent TOs experienced a fairly modest margin between their initial and final or updated project cost estimates on average, with final or updated project cost estimates falling below initial estimates, on average, in some ISOs/RTOs.

The Brattle Report argues, in part, that the solicitations will result in cost savings because the winning bids in some of the solicitations contained cost caps. However, any cost-savings associated with the projects selected through the solicitations held to date cannot be known until the projects are in service. In addition, as the Brattle Report notes, cost escalations are often unavoidable during the development process (e.g., uncertainties around materials and labor costs, or scope and routing changes due to regulatory siting and approval issues). Furthermore, some cost cap provisions have exclusions that permit the final cost of the winning proposal to exceed the cost of the developer's bid.[26]

These exclusions tend to cover the costs that are the most likely to increase by the greatest amount during the development process (e.g., route changes, regulatory issues). For example, the Duff-Coleman solicitation in MISO resulted in 11 competitive proposals, 10 of which included at least one type of cost cap.

26 Brattle Report, pp. 40-41.

Table 9: Duff-Coleman Solicitation Cost Caps

Summary of Cost Caps, Concessions, and Commitments											
Uncertainty	101	102	103	104	105	106	107	108	109	110	111
ROE		✓		✓ i			✓	✓ ii	✓ iii	✓	
Capital Structure		✓		✓						✓	
Implementation Costs	✓ iv	✓ v	✓	✓ iv		✓	✓	✓	✓ iv	✓	✓ iv
Operations and Maintenance Costs				✓							
Inflation Rate			✓	✓		✓		✓		✓	
Rate Concessions						✓					✓

i Limited duration ROE cap

ii Cap on weighted average cost of capital (includes ROE), limited duration

iii No ROE cap, but will forego ROE incentive adders in initial FERC filing

iv AFUDC is not included in the cap

v Only a portion of construction costs are capped

Source: Duff-Coleman Selection Report, Table 2-2, p. 26.

The Duff-Coleman bids also included various exceptions to cost caps, or other concessions, as shown in the table below.

Table 10: Duff Coleman Selection Report Cost Cap Exception Summary

Exclusion	Details
1. Project Routing	Some proposals exclude routing changes due to unseen soil conditions, river crossings, etc. Combination of general outs and specific per mile cost values (with/without dead band).
2. Material Escalation Costs	Some proposals include exceptions for construction costs that arise above inflation rate
3. Condemnation and Property Rights	Some proposals allow an increase to the construction cost cap for condemnation and property rights costs that exceed a specified percentage dollar value.
4. Five Year or Initial Filing Commitments	Some proposals commit to a cap for condemnation and property rights costs that exceed a specified percentage or dollar value
5. Regulatory	Some proposals note exclusions for environmental permitting, remediation, and mitigation
6. Non-Developer Driven Changes	Most proposals allow an increase to the construction cap for costs driven by changes from regulatory government agencies, local utilities, MISO, and Force Majeure.

Source: MISO, Duff Coleman Selection Report, December 20, 2016, p. 27.

As listed above, some proposals contained cost caps with several exemptions or exceptions. Such exclusions can have a significant impact on a project's final cost, often include issues for which it is difficult to accurately predict costs, and substantially mitigate the developer's risk. For example, a project routing change exemption significantly reduces risks for developers who propose a cap on total investment costs or revenue requirements. Failing to price the risk associated with significant cost changes could allow the developer to submit proposals with seemingly low and/or aggressive cost targets that may not materialize if the project experiences significant cost escalations (e.g., unexpected route changes).

The Designated Entity Agreement ("DEA") between PJM and Northeast Transmission Development ("NTD"), a subsidiary of LS Power, for the Artificial Island project provides an illustrative example. This developer agreement includes a non-standard provision that appears to establish a cap on "Construction Costs" at the lesser of actual costs or a Construction Cost Cap amount of $146 million, adjusted for escalation using the Handy-Whitman Index. However, the agreement contains several exceptions - including project scope changes directed by PJM (project scope is a significant cost driver) - to its construction cost cap:

> Schedule E Section (e)
>
> "Excluded Costs" means (i) any taxes, (ii) any financing costs, including any approved return on equity, Allowance for Funds Used During Construction, or similar allowance or financing cost or charge earned or accrued in connection with the Project during the period of development and construction of the Project (or thereafter), (iii) any costs and expenses associated with any PJM directed additions to or modifications of the Scope of Work (but only if and to the extent such costs and expenses are in excess of the costs and expenses that would have been incurred but for such addition to or modification of the Scope of Work), (iv) any costs and expenses incurred as a result of an Uncontrollable Force (but only if and to the extent such costs and expenses are in excess of the costs and expenses that would have been incurred but for such Uncontrollable Force) and (v) any costs and expenses associated with the operation and maintenance of the Project.[27]

Schedule E allows for cost recovery in excess of the stated cap under several conditions, many of which are classified as Force Majeure (or Uncontrollable Force).[28] This "out" may be a commonplace in other Developer Agreements as well. In addition to the Force Majeure provision, the language quoted above also includes exceptions for all taxes, changes directed by PJM, and operation and maintenance costs.

FERC accepted all terms and conditions contained in the DEA between PJM and Northeast Transmission Development.[29] These exclusions could create the impression that the winning project in a given solicitation has low costs, when in reality the final project costs can be higher than the winning developer's bid and potentially higher than the final costs of a competing project that was not selected. With such cost cap exclusions, some of the risks of cost overruns rest with the customer, not the winning developer. And, not only do risks remain on the customer, but incentives are created for developers to remove the cost of that risk (contingencies) from project bids, artificially deflating estimated costs.

Additionally, some of the cost caps reviewed by Concentric only cap transmission revenue requirements during a subset of the project's operational life. Such cost caps may unintentionally create incentives for developers to defer necessary investment in order to keep rates below the applicable cap. Several solicitations held to-date have included revenue requirement caps. For example, in the Suncrest project in CAISO, NextEra[30] agreed to a project construction cost cap of $42,288,000 in 2015 dollars, and an operation and maintenance ("O&M")

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27 Artificial Island PJM DEA Proposed Agreement, Schedule E, Section 1.2e.

28 Artificial Island PJM DEA Proposed Agreement, Schedule E, 1.2g.

29 *PJM Interconnection, L.L.C.*, 154 FERC ¶61,054, Order Accepting Proposed Agreement, (January 29, 2016).

30 CAISO, Suncrest Selection Report, http://www.caiso.com/Documents/SuncrestProjectSponsorSelectionReport.pdf

cost cap of $360,000 per year for the first five years of the project's operational life.[31] NextEra's winning bid in MISO for the Hartburg-Sabine line also included a cap on O&M for the first 10 years of the project.[32]

Capping items like O&M over a portion of a project's life may not be in the best interest of customers; it can create incentives to spend less on O&M to maintain a desired return, which can impair reliability and may significantly increase O&M costs in later years if materials fail. Furthermore, capping O&M expenditures in the first years of a project's life does not necessarily induce savings as O&M costs tend to be lowest in early project years given that equipment is relatively new. O&M costs tend to increase as the project ages, and the O&M related cost caps in the winning bids reviewed in Appendix C do not cap O&M late in a project's operational life.

Finally, cost caps can also be complex and potentially difficult to enforce. Even if there were an effective and transparent mechanism to monitor the cost caps of a given project, enforcement could be challenging because the cost caps are included in an agreement that the winning developer executes with the ISO/RTO (e.g., Approved Project Sponsor Agreement in CAISO or Designated Entity Agreement in PJM) but the project's annual revenue requirement and associated transmission rate is approved by FERC. In a recent paper regarding solicitations for transmission projects, Paul Joskow referred to this ambiguity as an "institutional gap."[33]

3.2. Brattle's Cost Savings Estimates are Flawed

3.2.1 Inaccurate Lower Bound Savings Estimate

Table 8 above summarizes the total number of solicitations that have been carried out as of April 2019 in the ISOs/RTOs versus the number of solicitations the Brattle Report focuses on to estimate savings. The experience with solicitations for new transmission projects in the ISOs/RTOs has been limited, particularly outside of CAISO and PJM.[34] The Brattle Report produced both lower bound and upper bound savings estimates for these solicitations.

This Subsection examines the "reference costs" Brattle used to estimate a lower bound on the savings Brattle claims have resulted from the solicitations.[35] To estimate savings from each solicitation, the Brattle Report compared the winning bid to a benchmark referred to as a "reference cost". The report used either an ISO planning estimate (CAISO, MISO, or SPP) or an incumbent TO bid (PJM or a third-party estimate of that bid in NYISO) as reference costs for the solicitations. Use of this reference cost methodology appears to have resulted in the Brattle Report not estimating savings for solicitations awarded to incumbent TOs in PJM and NYISO.

31 Approved Sponsor Agreement Between NextEra Energy Transmission West, LLC and California Independent System Operator Corporation, Exhibit NEET WEST-10, filed August 31, 2015 in CPUC Application No. A.15-08-027, http://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1508027/520/186580410.pdf, p. 43.

32 MISO, Hartburg-Sabine Selection Report, November 27, 2018, p. 24.

33 Joskow, Paul, Competition for Electric Transmission Projects in the U.S.: FERC Order 1000, Revised March 16, 2019, p. 22.

34 CAISO plans to hold solicitations for the Gate 500 kV Dynamic Reactive Support and Round Mountain Dynamic Reactive Support projects in 2019.

35 Brattle Report, figures 18 and 19. Brattle uses all 14 projects to estimate upper and lower bounds but presents results for only 13 of the projects in figure 19, presumably because the Walkemeyer and Gates Gregg projects were delayed.

However, if a solicitation in and of itself produces the savings the Brattle Report claims, the nature of the winning developer, incumbent or non-incumbent, is irrelevant. As described further below, using the report's reference cost methodology would have resulted in "negative savings" for the AP South solicitation in PJM.

Table 11: Brattle Report Estimated Range of Potential Savings from ISO/RTO Solicitations

	ISO or Incumbent Estimated Cost ($ million)	Winning Developer's Project Cost ($ million)	Lower Bound Savings Estimate (%)	Upper Bound Savings Estimate (%)
CAISO	$1,180	$833	29%	50%
ISONE	$n/a	$n/a	n/a	n/a
MISO	$181	$154	15%	28%
NYISO	$232	$181	22%	22%
PJM	$692	$280	60%	67%
SPP	$17	$8	50%	58%

Source: Brattle Report, April 2019, Figure 18, p. 41, see also Figure 19, p. 43.

The Brattle Report stated that it produced lower bound savings estimates by comparing the winning bid to either the ISO planning-level estimate for the project (CAISO, MISO, and SPP), or the lowest cost incumbent bid (PJM and NYISO).[36]

Given the nature of transmission project planning-level estimates discussed in Section 2, in our view, Brattle's lower bound savings estimates for the CAISO, MISO, and SPP solicitations are unsound. As discussed in Section 2 above, the precision of transmission project cost estimates increases as a project progresses through the development process and more information about project costs becomes available. Early planning-level estimates produced by the ISO/RTO are expected to differ significantly from the final project's costs because the ISO/RTO estimate is developed at a high level with general rather than specific estimates about the costs of various project components.

Therefore, comparing an early stage ISO/RTO planning-level estimate to the developer's fully developed project bid in a solicitation, as Brattle did for CAISO, MISO, and SPP, does not demonstrate the expected savings from conducting a solicitation compared to using another process. Instead, the Brattle Report's method provides an estimate of the accuracy (or inaccuracy) of the ISO/RTO's planning-level estimate. Furthermore, Brattle's use of the ISO/RTO planning estimate as a reference cost does not reflect the benefits from competition because the winning bidder is not competing with the ISO/RTO planning estimate but with the other bidders. As such, it would be more appropriate to compare the winning bid in a given solicitation to the bids of its competitors. Unfortunately, this information was not publicly available for CAISO.

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[36] Brattle Report pp. 28-29.

The Brattle Report claims that the 10 solicitations in CAISO produced savings of at least 29%.[37] Concentric reviewed the winning bids and CAISO planning level estimates Brattle used to produce this estimate and confirmed that Brattle used the high end of CAISO's planning level estimate for each solicitation when the CAISO estimate was a range (i.e., low and high cost estimates). Brattle's use of the high end of the CAISO planning-level estimates maximized the CAISO savings estimates. As described further in Appendix A, Concentric attempted to recreate Brattle Report's savings estimates of 7 of the CAISO solicitations and determined that using the low end of the CAISO planning-level estimate for each project yields "savings" of 3% and using the high end yielded estimated savings of 26%.[38]

MISO has conducted two solicitations for new transmission projects and the Brattle Report claims that these solicitations produced savings of at least 15%.[39] The Duff-Coleman solicitation was awarded to Republic Transmission, LLC, a partnership between Big Rivers Electric Corporation and LS Power, with a $49.8 million bid that was 15% below MISO's $59 million planning-level estimate.[40] The Hartburg-Sabine solicitation was awarded to NextEra for $103.9 million, which was also 15% below the MISO planning-level estimate.[41] Because they are based on MISO planning-level estimates, we find that Brattle's lower bound savings estimates for the MISO solicitations suffer the same flaws as the CAISO estimates.

SPP conducted one solicitation for the Walkemeyer project and the Brattle Report estimated savings of 18% from this solicitation that was awarded to Mid Kansas Electric Company.[42] Brattle's lower bound savings estimate from this solicitation was based on SPP's planning-level estimate for the Walkemeyer project and thus, in our view, flawed for the reasons described above. Brattle's estimated savings for this solicitation is included in Figure 18 of the Brattle Report but not in Figure 19, which summarizes the upper and lower bound savings estimates by ISO/RTO, presumably because the Walkemeyer project was canceled due to declining load projections.

The methodology the Brattle Report used to estimate cost savings from a solicitation in PJM is also flawed. Unlike CAISO, MISO, and SPP, PJM and NYISO employ a "sponsorship model" to solicit alternative transmission solutions during their regional planning processes. As such, PJM and NYISO do not release ISO/RTO planning-level estimates before each solicitation. Rather than solicit proposals for a specific transmission project (e.g., new substation), PJM and NYISO issue a more general transmission "need" and bidders submit potential solutions to satisfy that need.

37 Brattle Report, Figure 19, p. 43.

38 See the CAISO section of the Appendix C for more details about the transmission solicitations in CAISO. Note that Concentric was not able to confirm the cost of the winning bid for three of the 10 CAISO solicitations.

39 Brattle Report, Figure 19, p. 43.

40 MISO Duff-Coleman Selection Report, p. 38.

41 Brattle Report, Table 7. Hartburg-Sabine Selection Report, p. 5.

42 Brattle Report, Figure 18, p. 41. As noted above, Brattle excludes its savings estimates for the Walkemeyer project from Figure 19, presumably because it was canceled.

In PJM, bidders are generally not restricted as to the scope of the proposals they submit in response to PJM (e.g., PJM could receive proposals that range from battery storage to greenfield transmission lines). PJM publishes the project costs from the submitted proposals, so it is possible to compare the bids with each other. However, this comparison is not very informative for the purposes of estimating cost savings from the solicitation because the scopes of the projects may be vastly different, which means they have different costs and benefits. Furthermore, the proposals submitted by developers do not include the full cost of integrating the project with the PJM system. Unlike a project-based solicitation, where project integration costs across proposals are generally the same because the ISO/RTO has defined the project scope, the integration costs of proposals submitted in a sponsorship model solicitation can differ significantly. As such, the stand-alone developer bids in each proposal do not constitute the full costs of that proposal and the proposals cannot be compared with one another without also considering integration costs.

The Artificial Island solicitation attracted a variety of projects to address the identified needs; the proposed costs of those projects ranged from the low $100 million range to $1.5 billion. Brattle compared two competing bids to estimate a lower bound savings estimate of 60% (or $412 million) for the Artificial Island solicitation.[43] However the Brattle Report neglects to mention that the bids were from different points in time and for different project scopes. The Artificial Island solicitation was particularly complex. PJM first held a solicitation window for the project in 2013. PJM subsequently issued a supplemental solicitation in 2014. Prior to awarding the final project, PJM changed the project scope, the route and the RFP itself.

Concentric identified the sources of the data the Brattle Report used to estimate the purported savings for the Artificial Island solicitation. Brattle compared the costs of the winning bid, a proposal submitted by LS Power (though changed by PJM), to the costs of a project submitted by PSE&G at the very beginning of the solicitation process.[44] This comparison is highly problematic and does not constitute a meaningful estimate of cost savings from the Artificial Island solicitation. In fact, because of all of the changes that PJM made during the 4-year pendency of the solicitation process, the ultimate LS Power "proposal" was not really its proposal at all, as the winning bid had a different terminus point from the one LS Power initially proposed, and PJM had in fact changed the RFP itself.[45]

The Brattle Report did not use the AP South solicitation to estimate savings from solicitations in PJM despite the fact that the AP South solicitation was awarded to a non-incumbent – Transource, an affiliate of AEP. The Brattle Report estimates for PJM may have excluded the AP South solicitation from its cost savings estimate because the Transource project was not the lowest cost bid. As such, using the report's methodology to

43 Brattle Report, Figure 13, p 32.

44 PJM Interconnection, Artificial Island Project Recommendation White Paper (July 29, 2015) at p. 12 (Table 2.1). The Brattle Report appears to have used PSE&G's $692 million proposal, submitted in 2013, for project "P2013_1-7E", that included New Freedom-Deans 500 and Salem - Hope Creek 500 kV lines as major components.

45 See Appendix C for more details on the information used in the Brattle Report to estimate savings from the Artificial Island solicitation.

estimate savings for this solicitation would have resulted in a negative savings estimate. The fact that the lowest cost bidder wasn't selected in the AP South solicitation doesn't necessarily mean the solicitation wasn't worthwhile. As described further in Appendix C, the PJM Board selected the Transource proposal because PJM staff found that the proposal had many desirable attributes and a favorable estimated cost-benefit ratio.[46]

NYISO has carried out two solicitations for new transmission projects – Western NY and AC Transmission. The Brattle Report only used a lower bound savings (22%) for the Western NY solicitation.[47] The report did not estimate savings for the AC Transmission solicitation, presumably because one segment of the solicitation, which had two segments total, was awarded to an incumbent TO.

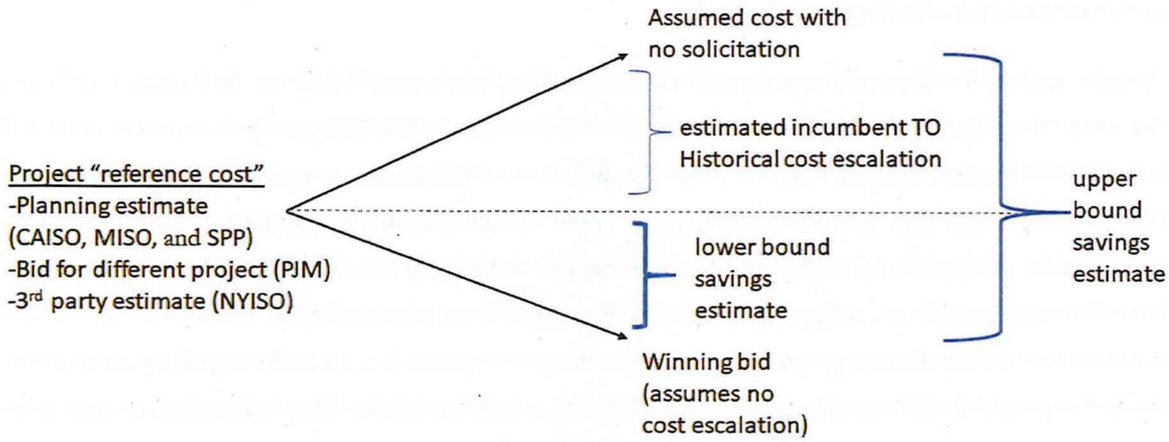
NYISO does not publicly release the costs contained in either the winning bid or bids that were not selected. Instead, NYISO releases project cost estimates produced by a third-party independent consultant based on the projects proposed in the solicitation. The Brattle Report compared these third-party engineering estimates and claimed that the difference between the estimates for two of the Western NY bids – one from two incumbents and another from a non-incumbent – represented savings from the Western NY solicitation.[48] It is not possible to determine how these third-party estimates compare to the actual bids submitted, so the Brattle Report's method to estimate savings from Western NY solicitation (22%) is highly speculative. Furthermore, given that NYISO uses a sponsorship solicitation model, the two proposals compared had entirely different scopes and differed on many dimensions other than cost, so limiting the comparison to third-party estimates of the two proposals' costs alone is not informative.

3.2.2 Methodologically Flawed Upper Bound Savings Estimate

This Subsection addresses the Brattle Report's upper bound savings estimates. We reviewed the upper bound savings estimates in the report and found that they were based on a methodologically flawed approach and used inaccurate assumptions about the historical cost escalations of incumbent TO projects in each ISO/RTO. Figure 3 presents a schematic that explains how Brattle produced its upper and lower bound savings estimates for the solicitations.

46 See e.g., PJM White Paper, Transource Independence Energy Connection Market Efficiency Project, November 15, 2018.
47 Brattle Report, Figure 18. *See also* Table 12.
48 See Appendix C for further details.

Figure 3: Brattle Report Method for Estimating Upper and Lower Bound Savings from ISO/RTO Transmission Solicitations



As described in Subsection 3.2.1, the Brattle Report determined lower bound savings estimates by comparing the winning bid (with no cost escalation) with either an ISO/RTO planning-level estimate or the lowest cost of a competing incumbent TO bid (or third-party estimate of that bid in NYISO). Upper bound savings estimates were determined by inflating the ISO/RTO planning-level estimate or incumbent TO bid by the inaccurate "average historical cost escalation" figures discussed in Section 2.

The Brattle Report states that its upper bound savings estimates for the solicitations accounts for the fact that the final costs of the projects can escalate above the winning bids.[49] As the Brattle Report notes, "the final costs of the competitively-awarded transmission projects may similarly increase beyond their proposed costs as some of the proposed project costs are indexed to inflation and as developers are able to make certain adjustments as they complete their final routing, siting, and construction."[50] Thus, as discussed in Subsection 3.2.1, even if the winning bid has a cost cap or caps, the final costs of a transmission project awarded through a solicitation can exceed the original submitted bid.

The Brattle Report asserts that the upper bound savings estimates account for the possibility of project cost escalation.[51] However, rather than applying its "average historical cost escalation" estimates – which as discussed in Section 2 are significantly overstated – to the winning bids themselves, Brattle inexplicably applies its average historical cost escalation estimate to each project's "reference cost" (i.e., the ISO/RTO planning-level estimate or a competing incumbent TO bid).

As shown in Figure 3 above, Brattle then compares the escalated reference cost – a figure the Brattle Report refers to as the "Expected Cost if Competitive Projects were not subject to Competition"[52] – to the winning bid

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49 Brattle Report, p. 42.

50 Brattle Report, p. 40. The "adjustments" Brattle referred to here are presumably the exclusions to the cost caps contained in the winning bids, which are described in Subsection 3.1.

51 Brattle Report, pp. 40-42.

52 Brattle Report, Figure 18, column 6.

with no escalation to produce an upper bound savings estimates for the solicitations in each ISO/RTO. This method is fundamentally flawed for two reasons.

First, Brattle applied its estimated cost escalation to the wrong figure, specifically the "reference cost" rather than the winning bid itself (i.e., the basis for Brattle's claimed savings in the first place). As noted in Section 3.1 and in the Brattle Report, the final cost of a project awarded in a solicitation can exceed the winning bid, even if the bid included a cost cap. It is not clear what the upper bound estimate is supposed to represent because the figure Brattle uses bares no relation to the winning bid, and simply assumes, without any basis, that the ISO/RTO planning estimate or competing TO bid will incur significant cost escalation. Furthermore, this upper bound estimate assumes that the project will only experience cost escalation if it is developed by an incumbent and will not experience *any* cost escalation if developed by a non-incumbent. This assumption is clearly false because any project developer - incumbent or not - faces development risks due to factors beyond its control (e.g., routing changes, other regulatory or environmental permitting issues, input cost changes for greenfield projects, equipment cost changes, inflation, etc.).

Comparing Brattle's inflated reference cost to the winning bid with no cost escalation does not provide a meaningful or informative upper bound estimate of savings and does not account for potential project cost escalation. This is evident by the fact that the Brattle Report's attempt to account for project cost escalation actually *increases* the estimated savings from the solicitations. It defies basic logic to claim, as Brattle does, that the savings from a solicitation would *increase* if the project's costs were to escalate above the winning bid.[53] To properly account for potential project cost escalation, the Brattle Report should have applied a cost escalation estimate to the winning bid itself. Such an approach would have *reduced* rather than *increased* Brattle's estimated upper bound savings from the solicitation.

The second flaw with the upper bound savings estimates is that the Brattle Report employed its inaccurate and overstated estimates of the cost escalation experienced by incumbent TOs to estimate this upper bound. We show in Section 2 that the report's estimates of incumbent TO cost escalation is vastly overstated and inconsistent with empirical evidence. Thus, in addition to using a methodologically flawed approach to account for cost escalation, Brattle's upper bound estimates also rely on inaccurate assumptions about incumbent TO projects.

Given these flaws, we find the lower and upper bound savings estimates in the Brattle report to be without merit. These estimates do not demonstrate significant savings as claimed in the Brattle Report and should not be relied upon for decision making purposes. As noted in Section 3.1, it is too soon to assess the cost impacts of the solicitations because the final cost impacts are only known for one of the 15 projects.

53 Brattle Report, p. 42.

4. Transmission Solicitations are Time and Resource Intensive

This Section describes some features of transmission solicitations that are important for decision makers and other stakeholders to consider before expanding solicitations beyond their current scope. The first consideration is the type of cost caps included in solicitations and the extent to which they reduce costs. As described above, Concentric found that the Brattle Report fails to demonstrate that the 15 solicitations its savings estimates are based on have produced any savings. A second consideration is the "administrative cost" of conducting a solicitation for a new transmission project. A third consideration is bidder preparation costs.

The Commission stated that one of the core objectives of the Order No. 1000 requirements was to achieve more efficient or cost-effective regional transmission planning.[54] The Commission did not specifically require regional transmission planners to conduct solicitations in the regional planning process.[55] Instead, it chose to afford ISOs/RTOs flexibility in implementing the Order No. 1000 requirements, based on the expectation that an open and transparent process that involved multiple entities and considers the transmission needs of all customers would help regional transmission planners identify solutions that are more efficient or cost-effective.[56] A narrow focus on solicitations for transmission development ignores the overriding purpose of Order No. 1000, which was to ensure all customers' needs were considered and there was an opportunity for more efficient or cost effective solutions to be identified.

All six FERC-jurisdictional ISOs/RTOs chose to conduct solicitations in their regional planning process, and some ISOs (e.g., CAISO) conducted solicitations before the Commission issued its third and final order on the Order No. 1000 requirements. Given that Brattle and others have advocated expanding the scope of solicitations in these ISOs/RTOs, it is important to examine the resources required to conduct these solicitations. These resources include, but are not limited to, the time it takes to conduct the solicitations, ISO/RTO costs to issue the solicitations, qualify bidders, review proposals, and select a winning proposal ("ISO/RTO implementation costs"), and bidder preparation costs. We refer to these as "administrative costs".

This analysis is not intended to claim or otherwise argue that solicitations for new transmission projects are never worthwhile. Rather, the intent of this Section is to highlight the resources involved in conducting the solicitations that have occurred to-date and some of the complexities experienced with some of the solicitations. This information should enable policymakers and the public to make more informed decisions about whether to expand these solicitations.

The evidence below, which is based on publicly available information, demonstrates that conducting solicitations in ISO/RTO regional transmission processes is a time and resource intensive process. The fact that conducting a solicitation involves costs does not in and of itself mean that solicitations are not worthwhile.

54 Order No. 1000, at P 2.
55 See Appendix D for additional details about the Order No. 1000 requirements and associated ISO/RTO compliance filings.
56 See e.g., Order No. 1000, at P 11.

Rather, it is generally worthwhile to conduct a solicitation for projects where the benefits expected from conducting a solicitation verses an alternative process (e.g., designating a specific developer to construct the project) exceed the costs of conducting that solicitation.

The Commission implicitly made such calculations in Order Nos. 1000, 1000-A, and 1000-B when it decided to exempt certain types of transmission projects from the Order No. 1000 requirements. For example, the Commission recognized that timeliness is a factor that must be considered in the transmission planning process and approved time-based exemptions from the Order No. 1000 requirement to remove the federal Right Of First Refusal ("ROFR") in PJM, ISO-NE, and SPP for certain new transmission projects needed to address reliability.

Three types of administrative costs of conducting a solicitation – time-related costs, ISO/RTO implementation costs, and bidder preparation costs – are discussed in turn below.

4.1. Time-Related Costs

Time is arguably the most expensive resource associated with transmission solicitations. It is inherently difficult to assign a monetary value to time, and this report makes no attempt to do so. Instead, we summarize the number of days it took to carry out each solicitation, information the reader can use to make his or her own evaluation. Solicitations take time to prepare, review, issue, and administer. Bidders also spend time and resources preparing bids, and the ISO/RTO staff (which may include third party consultants) must review and ultimately select among the competing proposals. In addition, time delays may impact project implementation, denying customers the benefit of the project.

Table 12 summarizes the time involved to conduct the solicitations that have been carried out in Order No. 1000-compliant ISO/RTO regional planning processes as of the writing of this report. The time involved in conducting the solicitation and selecting a winning proposal delays a given project's implementation, which also delays the benefits (e.g., lower congestion costs, increased reliability, etc.) of the project.

Table 12: Time Involved in Transmission Solicitations

Project	Date Need Identified	Solicitation Window	Date of ISO/RTO Board Approval	Days Between Identification and Board Approval
Imperial Valley	CAISO	Dec. 20, 2012- Feb. 19, 2013	Jul. 11, 2013	113
Gates-Gregg	2012-2013	Apr. 1- Jun. 3, 2013	Nov. 6, 2013	231
Sycamore-Penasquitos	Transmission Plan, Mar. 20, 2013	Apr. 1 - Jun. 3, 2013	Mar. 4, 2014	349
Suncrest		Apr. 16 - Jun. 16, 2014	Jan. 6, 2015	174
Delany Colorado River		Aug. 19 - Nov. 19, 2014	Jul. 10, 2015	359
Estrella	CAISO 2013-2014	Apr. 16 - Aug. 18, 2014	Mar. 11, 2015	238
Harry Allen to Eldorado	Transmission Plan,	Jan. 30 - Apr. 30, 2015	Jan. 11, 2016	544
Miguel†	Jul. 16, 2014	Apr. 16 - Jun. 16, 2014	Sep. 9, 2014	55
Spring		Apr. 16 - Aug. 18, 2014	Mar. 11, 2015	238
Wheeler Ridge		Apr. 16 - Aug.18, 2014	Mar. 11, 2015	238
Duff-Coleman	MISO MTEP-15, Dec. 1, 2015,	Jan. 9 - Jul. 6, 2016	Dec. 20, 2016	385
Hartburg-Sabine	MISO MTEP-17, Dec,1, 2017	Feb. 6. - Jul. 20, 2018	Nov. 27, 2018	361
Walkemeyer	SPP 2015 ITP, Jan. 20, 2015	May 5- Nov. 2, 2015	Apr. 12, 2016	448
Artificial Island‡	PJM 2012 RTEP, Feb. 28, 2013	Initial: Apr. 29 - Jun. 28, 2013 Supplemental: Aug. 12- Sep. 19, 2014	Initial: July 29, 2015 Revised: April 6, 2017	1,498
AP South	PJM 2013 RTEP, Feb 28, 2015	Oct. 30, 2014- Feb. 27, 2015	Aug. 9, 2016	893
NY Western Public Policy	NYISO - July 20, 2015 NYPSC Order	Nov. 1, 2015- Jan 1, 2016	Oct. 17, 2017	820
AC Transmission+	NYISO - Dec. 17, 2015 NYPSC Order	Feb. 29, 2016- Apr. 29, 2016	April 8, 2019	1,208

† The Miguel solicitation had a single bidder – San Diego Gas & Electric.
‡PJM staff made an initial selection in the Artificial Island solicitation on Jun. 16, 2014. The PJM Board made an initial selection on Jul. 29, 2015, suspended the project in August 2016 for further consideration, and approved a revised scope in April 2017. See the case study in Subsection 4.2 for more details.
+The NYISO Board revised NYISO staff's recommendation for one segment of the AC Transmission solicitation

Once a need is identified, the next step is to solicit proposals, which are RFPs for specific projects under the project model (e.g., CAISO) and more broadly defined transmission needs under the sponsorship model (e.g., PJM). The next step is the solicitation window, which typically lasts between 60 and 120 days. As indicated in Table 12, the ISO/RTO may choose to amend the solicitation requirements, or seek additional information from bidders, which adds time to the solicitation window. Next, the ISO/RTO staff, sometimes with the help of independent consultants, evaluates the proposals according to the metrics specified in the tariff and prepares a recommendation. This selection process and the recommended selection (i.e., the winning proposal) are typically described in a selection report. ISO/RTO staff then submits the selection report and makes a formal recommendation to the ISO/RTO board. The board typically accepts staff's recommendation, although this is not always the case (e.g., the AC Transmission solicitation in NYISO).[57]

As shown in Table 12, solicitations in ISO/RTO regional planning processes with more than a single bidder can take a significant period of time, ranging from 113 to 1,498 days. The longest solicitation was for Artificial Island in PJM, where PJM staff made significant amendments to the proposed project scope during the staff evaluation phase and subsequently amended the submitted proposals.[58] The case study below describes the issues PJM and its stakeholders experienced during the Artificial Island solicitation.

Artificial Island Case Study

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. On April 29, 2013, PJM issued a problem statement and opened a 60-day proposal window to address the Artificial Island issues. Bidders submitted 26 separate proposals with cost estimates ranging from approximately $100 million 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.[59] At a Transmission Expansion Advisory Committee (TEAC) meeting in May 2014, PJM staff explained to stakeholders that it changed technical specifications within the proposals.[60]

In a June 2014 presentation to the TEAC, PJM staff indicated that it would recommend that the PJM Board approve the PSE&G proposal, which involved a 500 kV transmission line between Hope Creek and Red Lion 500 kV substations and associated substation work.[61] After the close of the bidding window, LS Power amended its bid to include a cost cap. Additional stakeholders also submitted comments on PJM staff's recommendation. As a result, the PJM Board decided to defer action on Staff's recommendation. The PJM Board also sought further information, through a supplemental proposal, from a shortlist of projects.[62]

On August 12, 2014, PJM requested supplemental information on the final terms of the proposed project costs from the shortlisted bidders and asked for responses by September 12, 2014.[63] In August 2014, PJM also requested the assistance of FERC's Alternative Dispute Resolution office to assist in PJM's discussions with the shortlisted bidders. PJM announced at an April 2015 TEAC meeting about Artificial Island that it would recommend that the PJM Board approve the LS Power proposal, which also required integration work that would be carried out by Public Service Electric & Gas (PSE&G) and Delmarva Power Light. PJM summarized its revised recommendation in a July 29, 2015 whitepaper.[64]

57 See Appendix C for details of NYISO's AC Transmission solicitation.

58 See Appendix C for details of PJM's Artificial Island solicitation.

59 PJM Interconnection, Artificial Island White Paper, July 29, 2015, at 11.

60 In an Answer to a complaint filed by PSE&G, PJM explained that the modifications included: (1) the construction of a static VAR compensator (SVC), as proposed by some bidders, at a substation where it would be built and owned by PSE&G, in order to improve stability performance; (2) the relocation of the connection point within a substation in two proposals to eliminate a critical fault; (3) the removal of breaker schemes proposed in some proposals in favor of a ring bus modification proposed by one of the bidders; and (4) the removal of certain transmission lines from several proposals because, with the construction of a SVC, the additional facilities were not needed to pass applicable reliability criteria testing and therefore their removal would reduce costs and improve constructability. Public Service Electric and Gas Company, Order Denying Complaint 151 FERC ¶ 61,229 (June 16, 2015) at n. 28 (citing PJM's March 11, 2015 Answer at 12-13).

61 PJM Interconnection, Artificial Island Recommendation, at 36, presented at the June 16, 2014 TEAC meeting. As explained above, PJM ultimately changed its mind and removed the SVC from the project scope when it awarded the revised project to LS Power in response to concerns about total project cost.

62 PJM Board Letter to TEAC members, July 23, 2014.

63 PJM, Artificial Island Supplemental Proposal Request, August 12, 2014.

64 PJM, Artificial Island Recommendation White Paper, July 29, 2015.

The PJM Board approved the Artificial Island Project in July 29, 2015. However, PJM initially underestimated the cost of integration work at the terminus PSE&G substation. PJM's revised estimates raised the estimated total cost, reflecting inclusion of the integration costs with the PSE&G system, of the LS Power Proposal.[65] This cost increase, in part, led the PJM Board to suspend the project in August 2016, and the Board directed PJM staff to conduct a more comprehensive analysis. During the reevaluation, PJM staff eliminated certain project elements (including the construction of an SVC) to lower cost, 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.[66] As a result, the project 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. The table below, an excerpt from a March 2017 PJM staff presentation to the TEAC, shows how the cost estimates from the Artificial Island project changed over time as PJM changed the project scope and updated cost estimates for various components of the proposal.

Cost Estimates of Selected Artificial Island Project ($ millions)

Project Component	Initially approved project scope (July 2015)	Cost Update (Feb. 2016)	Final approved project scope (Mar. 2017)
230 kV Line and Silver Run Substation	$146	$146	$146
Salem Interconnection	$61-74	$152	
Hope Creek 2B Interconnection			$132
OPGW	$25	$39	
New Freedom SVC	$38	$81	
DE Interconnection	$2	$2	$2
Project Total	$272-285	$420	$280

Source: PJM Interconnection, *Artificial Island*, presented at a March 3,2017 TEAC meeting, at 13.

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.[67]

Given the significant irregularities associated with this solicitation, it is not clear why the Brattle Report relied on the Artificial Island solicitation to draw any conclusions about the benefits of or cost savings of transmission solicitations. Indeed, we are surprised the report appears to present Artificial Island as a successful solicitation. In our view, the time required to conduct these solicitations (see Table 12) validates the Commission's findings in Order Nos. 1000, 1000-A, and 1000-B and in the ISO/RTO compliance filings that it may not be feasible to conduct a solicitation for a transmission project that is needed within a fairly short timeframe (e.g., reliability project).[68]

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

66 PJM Press Release, PJM Board Lifts Suspension of Artificial Island, April 6, 2017.

67 PJM Board letter to PJM Stakeholders, April 6, 2017. This letter also noted the cost allocation issues associated with the project.

68 See e.g., *PJM Interconnection, L.L.C., et al.*, Order on Compliance Filings, 142 FERC ¶ 61,214 (Mar. 22, 2013) at P 247. Section 5 and Appendix E discuss Order No. 1000 precedent regarding transmission projects needed to address reliability.

4.2. ISO/RTO Implementation Costs

ISO/RTO staff time and resources represent another cost of conducting a solicitation. Specifically, the time, money, and resources spent preparing, issuing, reviewing and evaluating, and selecting a winning proposal. These costs are allocated to the bidders rather than to load, but they are still incurred and likely to be recovered from load and thus should be considered when evaluating whether to conduct a solicitation in the first place. Some ISOs/RTOs have documented the implementation costs incurred to conduct a solicitation while others have not. Publicly available information about these implementation costs is summarized in Table 13 below.

Table 13: Summary of ISO/RTO Costs Incurred to Implement Solicitations in Regional Transmission Planning Processes

Project/Window	ISO/RTO	Cost Incurred
Suncrest	CAISO	$260,572
Delaney to Colorado River	CAISO	$530,359
Estrella	CAISO	$206,104
Harry Allen to Eldorado	CAISO	$434,703
Wheeler Ridge Junction	CAISO	$151,179
Miguel*	CAISO	$15,056
Spring 230 kV Substation	CAISO	$165,912
Duff-Coleman	MISO	$1,331,940
Hartburg-Sabine	MISO	$1,137,240
Walkemeyer	SPP	$522,196
2016 Windows 1-3	PJM	$457,717
2016/17 Long Term Window	PJM	$902,115
2017 Window 1	PJM	$328,287

Notes: The accounting the ISOs/RTOs employed to produce these estimates is somewhat unclear and the ISO/RTO figures may include different cost categories. The Miguel solicitation had only one bidder. PJM costs only refer to proposal evaluation costs. See Appendix C for data sources.

The ISO/RTO's direct implementation costs alone should be considered to constitute a lower bound on the actual costs expended on competitive solicitations because several stakeholders, such as the bidders, incumbent TOs, and other interested stakeholders (e.g., load advocates, state regulators) also expend resources by participating in a competitive solicitation. There is also an opportunity cost of conducting a competitive solicitation because ISOs/RTOs generally have limited resources with an obligation to operate the system and administer markets as well as comply with FERC regulations. The CAISO implementation cost estimates in Table 13 appear quite conservative when compared to the costs incurred to conduct competitive solicitations in MISO and SPP. For example, CAISO carries out a process that involves the same general steps as MISO and SPP, where it first issues technical specifications and selection criteria prior to each solicitation, and subsequently prepares a selection report that describes how CAISO staff evaluated the proposals and selected a winning bid (CAISO selection reports are about 100 pages long).

MISO estimates that it incurred $1,331,940 to select the winning developer in the Duff-Coleman solicitation. MISO recovered these costs from the 11 bidders through a combination of an initial $100,000 deposit from each bidder and an additional invoice of $21,086. MISO estimated that about 26% of the Duff-Coleman solicitation implementation costs were associated with the cost estimate, while the balance of costs incurred were associated with issuing the RFP (13%), assessing the design (17%), project implementation (13%), operations & maintenance (16%) components of each proposal, and the administrative and management and selection report costs (15%).[69] MISO estimated a similar cost to conduct the Hartburg-Sabine solicitation.

After conducting the Walkemeyer solicitation, SPP and its stakeholders evaluated the competitive solicitation to identify "lessons learned". SPP explained in a filing with FERC the costs SPP incurs to "contract, retain, and train" the group of third-party industry experts it hires to evaluate the proposals submitted in competitive solicitations – referred to as the Industry Expert Panel. SPP estimated it incurs a minimum of $300,000 per solicitation to select and retain the Industry Expert Panel.[70] Furthermore, SPP's $300,000 minimum cost estimate does not include any recoverable SPP time involved in selecting and retaining the Industry Expert Panel.[71]

SPP reported that the full cost of administering the Walkemeyer solicitation was $522,196, consisting of $87,468 for SPP staff expenses, $322,058 for the Industry Expert Panel, and $112,670 for the Industry Expert Panel consultant.[72] On September 20, 2017, SPP referenced the Walkemeyer review costs it incurred in a proposal with FERC to revise its tariff and only hold a competitive solicitation through the SPP regional transmission planning process for projects with an estimated cost of at least $3 million. The Commission rejected SPP's proposal without prejudice on grounds that SPP failed to sufficiently explain the proposed $3 million threshold or demonstrate that it was just and reasonable and not unduly discriminatory or preferential.[73]

Finally, ISO/RTO presentations and stakeholder materials suggest that it can be difficult for ISO/RTO staff to evaluate and compare multiple proposals that contain various cost caps. For example, PJM notes that each

69 MISO, ISO's Planning Advisory Committee Competitive Transmission Monthly Update, March 15, 2017, at 6, available at https://cdn.misoenergy.org/20170315%20PAC%20Item%2003b%20CTA%20Update89803.pdf. See also https://cdn.misoenergy.org/Incurred%20Costs%20-%20Duff-Coleman%20EHV%20345kV82322.pdf.

70 SPP, Order Rejecting Tariff Revisions, 161 FERC ¶ 61,199 (November 17, 2017), at P 6. See also SPP Transmittal Letter, Docket No. ER17-2523, p. 4-5.

71 SPP Transmittal Letter, Docket No. ER17-2523 (Sept. 20, 2017) p. 4-5.

72 SPP Transmittal Letter, Docket No. ER17-2523 (Sept. 20, 2017) p. 4-5 citing the SPP July 7,2016 Strategic Planning Committee – Order 1000 Workshop Meeting Minutes, p. 33, available at https://www.spp.org/documents/40327/spc%20workshop%20minutes%2020160707.pdf

73 *Southwest Power Pool, Inc.*, Order Rejecting Tariff Revisions, 161 FERC ¶ 61,199 (November 17, 2017), at PP 10-13.

proposal from a given solicitation involves project-specific (e.g., constructability and associated risk factors), legal, and financial risks that must be evaluated and compared against other proposals. PJM plans to implement a new process to assess these risks and the new process will require PJM to hire independent consultants to conduct feasibility studies and a separate financial consultant to assess the proposals' financial risks. PJM states it will adjust its fee structure upward to account for these additional evaluation costs, which will be assessed to bidders.[74]

4.3. Bidder Preparation Costs

Bidders also incur costs to prepare proposals for ISO/RTO solicitations for new transmission projects. For example, Southwestern Public Service Company[75] sought a Declaratory Order from the Public Utility Commission of Texas to prevent SPP from issuing a competitive solicitation for the Potter – Tolk line because the company estimated it would cost at least $750,000 to respond to the solicitation.[76] Although the load does not pay these costs directly, they are still incurred by market participants and ought to be considered. Additionally, bidder preparation costs can be aggregated over time and converted into a regulatory asset that can later be recovered in transmission rates if the winning bidder becomes a transmission owner in a given ISO/RTO. For example, in March 2017 Republic Transmission, which won the Duff Coleman solicitation in MISO, petitioned FERC for certain transmission rate incentives related to the Duff-Coleman project, including the deferred recovery of prudently incurred pre-commercial costs through creation of a regulatory asset.[77] Bidder preparation costs are largely undocumented, but the limited publicly available information about such costs (e.g., Potter – Tolk line) suggests they are not trivial. The Brattle Report claims that these costs will decrease over time as bidders gain experience,[78] which may be true on a project-specific basis, but bidder preparation costs, which can involve detailed engineering estimates and securing financial guarantees, will never be driven to zero, and if solicitations expand so too will the number of bids.

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74 *See e.g.,* PJM, Cost Containment Status and Next Steps, presented to the PJM Planning Committee on May 16, 2019.

75 Southwestern Public Service company serves retail electric customers in the Panhandle and South Plains areas of Texas (entirely outside of ERCOT) and in southeastern portions if New Mexico.

76 Joint Petition of Southwestern Public Service Company and Southwest Power Pool, Inc. for Declaratory Order, PUCT Docket No. 46901 (February 28, 2017) at p. 11, available at http://interchange.puc.texas.gov/Documents/46901_1_930801.PDF.

77 *Republic Transmission, LLC,* Order Granting Petition for Declaratory Order, 161 FERC ¶ 61,036 (October 6, 2017) at P 21.

78 Brattle Report, p. 39.

5. No Basis to expand Order 1000 solicitations

This section explores the regulatory implications of Brattle's proposal to expand solicitations for new transmission projects beyond the scope the Commission required when it issued Order No. 1000. Brattle's savings estimates simply assume that a significant expansion is feasible and the report states that "if only 25% of U.S.-wide investment was subjected to competition and competitively developed projects yielded 20% cost savings", customers would save between $4.4-$6.6 billion over five years.[79] Brattle also estimates that if solicitations were held for 33% of all U.S.-wide transmission investment, savings would increase to $6-9 billion over five years.[80] However, Brattle does not specify what types of new transmission projects would be included or how such an expansion would be carried out.

Another issue with the Brattle Report's claims that potential savings of up to $9 billion are possible is that Brattle applied its flawed historical cost escalation estimate to *all* transmission projects (or at the very least a much broader group of transmission project types). However, the types of projects that would necessarily be included in such an expansion – such as local reliability projects, asset management projects, and upgrades – generally face much lower cost escalation risks than the subset of incumbent TO projects that form the basis of the Brattle Report's estimates.

For example, Brattle's analysis of ISO-NE projects included only 14 major projects, many of which were greenfield projects. Greenfield projects face considerably more risk than the full gamut of transmission projects. For example, a relatively modest upgrade to an incumbent TO's substation does not generally involve risks associated with right-of-way and may not require a certificate of public need and necessity.

Significantly expanding the scope of transmission projects selected through solicitations to achieve the purported savings claimed in the Brattle Report, especially to 25% or 33% of total US investment, would also require a shift in FERC policy about regional and local transmission planning and would involve revisiting several key decisions in Order No. 1000, 1000-A, and 1000-B. An expansion would also be inconsistent with recent Commission precedent about local transmission planning where the Commission generally found that Order No. 890 does not require local transmission planning to be conducted through the ISO/RTO regional planning process.[81] The Brattle Report offers no basis to revisit this precedent and we find that the Commission's reasoning in the Order No. 1000 proceedings was sound and remains sound based on the experience of the solicitations held to-date. Expanding the scope of solicitations throughout the US would also likely require changes in state law with respect of rights of first refusal, which the Brattle Report acknowledges.[82] Given the issues Concentric identified in the Brattle Report, we find no basis to do so.

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79 Brattle Report, p. 13.

80 Brattle Report, p. 13. Brattle assumes that US transmission investment over the next five years will be $100 billion and applies a 20% savings associated with conducting solicitations for new transmission projects. *See* Brattle Report, Figure 4, p. 13.

81 Monongahela Power Company et al. 164 FERC ¶ 61,217 (September 26, 2018), at P 13.

82 Brattle Report, p. 21.

The Brattle Report recommends that stakeholders and policymakers review and "potentially modify the criteria" used to determine the transmission projects eligible for solicitation under existing Order No. 1000-compliant planning processes in FERC-jurisdictional ISOs/RTOs. The report concedes that changing the scope of projects eligible for solicitation "may require modifying the requirements of Order No. 1000."[83] Given that the Commission has already found the regional transmission planning processes in these ISOs/RTOs to be just and reasonable and compliant with Order No. 1000, Brattle's recommendation would most certainly require revisiting some of the key findings in Order No. 1000, and recent Commission precedent about local planning.

In light of the Brattle Report's recommendation to expand the scope of transmission projects in ISO/RTO regional planning processes that are eligible for competition, Concentric reviewed the rationale the Commission used in Order Nos. 1000, 1000-A, and 1000-B to determine the applicability of those reforms. We also analyzed the Commission's reasoning and determinations in the individual ISO/RTO compliance filing orders where the Commission determined that the current planning processes in the ISOs/RTOs are just and reasonable and comply with Order No. 1000 requirements. Our review of Order No. 1000 precedent is contained in Appendix E.

Based on this review, we found that the Commission consciously targeted Order No. 1000 reforms to apply to a subset of *new* transmission projects that were selected in a *regional transmission plan* for purposes of *regional cost allocation*.[84] We believe that the Commission's choice to exclude certain types of transmission projects from the requirements of Order No. 1000 was appropriate at the time and remains appropriate. Given the flaws we identified in Brattle's "cost savings" estimates, we do not believe Brattle has demonstrated that expanding the scope of the Order No. 1000 requirements would produce the savings Brattle claims. Nor are we persuaded that the Commission's determinations in the Order No. 1000 proceeding or the subsequent ISO/RTO compliance filings are no longer just and reasonable.

As discussed in turn below, and in further detail in Appendix E, Order No. 1000 requirements do not apply to certain categories of transmission projects: (1) upgrades; (2) local transmission projects with costs that are not shared regionally; and (3) certain reliability projects. Each category and the rationale the Commission used to exclude such projects from Order No. 1000 is discussed in turn below.

5.1. Upgrades

The Commission affirmatively found that certain Order No. 1000 reforms only apply to *new* transmission facilities selected in a regional plan for purposes of cost allocation, and not upgrades.[85] As such, under Order No. 1000 reforms, incumbent TOs could retain a federal ROFR to upgrade their own transmission facilities. For example, the Commission stated that the Order No. 1000 reforms "do not affect the right of an incumbent

83 Brattle Report, p. 22.
84 Order No. 1000, p. 1.
85 Order No. 1000 at P 319 and Order No. 1000-A at P 357. See also Order No. 1000-B at P 41.

transmission provider to build, own and recover costs for upgrades to its own transmission facilities".[86] The Brattle Report notes that, consistent with the Order No. 1000 reforms, upgrades are excluded from solicitations in current ISO/RTO regional planning processes but suggests that "a vague or overly broad application of this clause" or "favoring upgrades over potentially more valuable transmission...limits the region from realizing the additional cost-efficiencies" that the report claims are possible from solicitations.[87]

In fact, there are often many good reasons to pursue upgrades to existing facilities in lieu of building a new transmission facility, including lower costs, minimal impacts to customers and landowners, and more efficient siting and permitting processes. In addition, in Order No. 1000-A, the Commission explicitly defined an upgrade as an "improvement to, addition to, or replacement of a part of, an existing transmission facility" and clarified that the term upgrade does not refer to an entirely new transmission facility.[88] Based on our review of the ISO/RTO Order No. 1000 compliance filings, the Commission carefully reviewed the proposed ISO/RTO tariffs to ensure that the ISO/RTO tariffs defined the term upgrade in a manner consistent with the definition provided in Order No. 1000-A.

5.2. LOCAL PROJECTS

Brattle argues that the determination the Commission made in Order No. 1000 to exclude local projects from the reforms has "greatly limited the scope" of competition in MISO.[89] Brattle recommends reviewing this exclusion and others. However, Order No. 1000 did not require ISOs/RTOs to eliminate an incumbent TO's federal ROFR to construct "local transmission facilities," where the Commission defined a "local transmission facility" as a "transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation."[90] The Commission would have to revisit this precedent to adopt Brattle's recommendation, but the report provides no basis or evidence to do so.

The Commission would also have to revisit more recent precedent that was not related to the Order No. 1000 proceeding. In August 2018, the Commission addressed applicability of Order No. 890 and expounded upon its view of local versus grid expansion projects when it rejected a complaint filed by California parties ("CPUC *et. al.*") against PG&E. Specifically, the Commission found that PG&E's "asset management projects", which were local transmission projects that were not selected through CAISO's regional planning process and not allocated regionally, were not subject to Order No. 890 requirements because such projects did not expand the transmission grid.[91]

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86 Order No. 1000 at P 319. See also Order No. 1000-A, P 426.
87 Brattle Report, p. 21.
88 Order No. 1000-A at P 426.
89 Brattle Report, pp. 20-21.
90 Order No. 1000 at P 63.
91 "[t]he transmission planning reforms that the Commission adopted in Order No. 890 were intended to address concerns regarding undue discrimination in grid expansion. Accordingly, to the extent that PG&E asset management projects and activities do not

In the same order, the Commission made a distinction between PG&E's asset management projects, which did not incrementally expand the grid but may incidentally do so, and grid expansion projects, which did incrementally expand the grid.[92] As such, expanding solicitations beyond the current scope (i.e., new transmission projects selected through a regional transmission plan for purposes of regional cost allocation) as Brattle suggests, would run contrary to recent precedent that found that local projects, such as asset management projects in PG&E, do not constitute grid expansion. Brattle also expressed concerns with the fact that some transmission investment occurs outside of the ISO/RTO regional planning process. The Commission's determination in the CPUC *et. al.* complaint suggests that the Commission finds such an arrangement just and reasonable, and compliant with Order No. 890.

The Brattle Report's proposal to require that a greater proportion of transmission projects be coordinated through the ISO/RTO regional transmission planning process is also inconsistent with recent Commission precedent in PJM. In September 2018, the Commission found that Order No. 890 did not require incumbent TOs in PJM to transfer their local planning process over to PJM. Instead, the Commission found that incumbent TOs retain primary authority over planning local or Supplemental Projects. Specifically, the Commission explained that "[w]hen transmission owners participate in an RTO, the Commission did not require them to allow the RTO to do all planning for local or Supplemental Projects... The PJM Transmission Owners therefore may retain primary authority for planning local Supplemental Projects..."[93] The Commission would have to revisit this finding to adopt the recommendation to conduct more local transmission planning through the ISO/RTO-coordinated regional planning process, yet the Brattle Report presents no compelling evidence to do so.

5.3. Reliability Projects

Based on our review, we found that the Commission carefully weighed reliability concerns in the Order No. 1000 proceeding. For example, the Commission explicitly recognized an incumbent TO's need to maintain reliability within its local area:

"We clarify that our actions today are not intended to diminish the significance of an incumbent transmission provider's reliability needs or service obligations. Currently, an incumbent transmission provider may meet its reliability needs or service obligations by building new transmission facilities that are located solely within its retail distribution service territory or footprint."[94]

In Order No. 1000 compliance proceedings, the Commission recognized that there may be insufficient time to carry out a solicitation if a project is needed to maintain reliability. For example, the Commission approved,

expand the grid, they do not fall within the scope of Order No. 890." *CPUC et al v. PG&E,* Order Denying Complaint, 164 FERC ¶ 61,161 (August 31, 2018), P 66.

92 The Commission found that only grid expansion projects are subject to Order No. 890 reforms. *Id.*

93 *Monongahela Power Company et al.* 164 FERC ¶ 61,217 (September 26, 2018) at P 13.

94 Order No. 1000 at P 262.

with modifications, PJM's proposal to forego solicitations for certain reliability projects that needed to be in service by a certain date to address reliability concerns: "We agree with PJM that there may be instances in which it may not be feasible to hold a competitive solicitation process to solve a reliability violation. Thus, to avoid delays in the development of transmission facilities needed to resolve a time-sensitive reliability criteria violation, we find that it is just and reasonable to include a class of transmission projects that are exempt from the competitive solicitation."[95] The Commission approved similar tariff provisions in ISO-NE and SPP.[96]

We believe the experience with the solicitations that have been held to date have proven the Commission correct. For example, Table 12 in Section 4 shows the timelines of the solicitations with more than one bidder ranged from a low of 133 days to a high of 1,498 days. Given the amount in of time involved, conducting solicitations for transmission projects needed to address a reliability issue may conflict with Commission's recent interest in enhancing the reliability and resilience of the transmission grid.

5.4. State Granted Rights-of-First Refusal

Finally, as explained further in Appendix E, the Commission clarified in Order No. 1000-A that the requirement to eliminate a federal ROFR in certain circumstances does not affect or preempt state laws regarding ROFRs that state or local governments might grant to incumbent TOs because the Order No. 1000 requirements were "focused on Commission-jurisdictional tariffs and agreements, and are not intended to preempt state or local laws or regulations."[97] Accordingly, as the Brattle Report notes,[98] expanding solicitations, especially by a significant degree, would also require changing state or local laws.

95 *PJM Interconnection, L.L.C.*, et al., Order on Compliance Filings, 142 FERC ¶ 61,214 (Mar. 22, 2013) at P 247.

96 See *ISO New England Inc.*, Order on Compliance Filings, 143 FERC 61,150 (May 17, 2013) at PP 235-236 and *Southwest Power Pool, Inc.*, Order on Compliance Filings, 144 FERC ¶ 61,059 (July 18, 2013) at PP 195-199.

97 Order No. 1000-A, at P 379.

98 Brattle Report, p. 21.

6. CONCLUSION

Based on Concentric's review, the results of the Brattle Report are inaccurate and as such, provide no basis to expand the scope of competitive solicitations in FERC-jurisdictional ISOs/RTOs. First, Concentric found that incumbent TOs do not experience the cost overruns claimed in the report. To the contrary, publicly available data from ISOs/RTOs with cost tracking databases suggests that incumbent TOs experience insignificant to very modest changes, ranging from -2.9% to 7.0%, between initial cost estimates and final or updated project cost estimates.

Second, it is not possible to estimate potential savings from the solicitations because the final costs are not known and the cost caps in some of the winning bids are not guaranteed to contain costs. Furthermore, Brattle's savings estimate for the solicitations are inaccurate because Brattle uses an inappropriate benchmark to estimate lower bound savings from the solicitations. The upper bound estimates are also methodologically flawed and rely on over-stated "cost overrun" estimates for incumbent TOs.

Third, expanding the scope of transmission projects selected through competitive solicitations could be inconsistent with the reliability and resilience goals the Commission expressed in recent orders and would require the Commission to directly contradict recent precedent regarding the applicability of Order No. 890. Expanding the scope of solicitations for new transmission projects would also require the Commission to revisit several of its findings in Order No. 1000 as well as more recent orders.

The Brattle Report does not present any credible evidence to suggest that the scope of solicitations for transmission projects should be expanded. However, if there is interest in expanding solicitations for transmission projects, we advise policymakers to wait until more of the projects selected through such solicitations have been placed in service. At such a time, more information will be available about the actual costs and operational performance of these projects and policymakers would be in a position to make better informed decisions about whether or not to expand such solicitations.

APPENDIX A: REVIEW OF INCUMBENT TO COST ESTIMATES

This appendix describes Concentric's analysis of the extent to which incumbent TOs' initial transmission project cost estimates compared to final or updated cost estimates. Concentric conducted this analysis to assess the accuracy of Brattle's estimates of the same figures. A discussion of the data and methods Concentric used to assess the Brattle estimates and produce its own estimates are described below for ISO-NE, MISO, PJM, SPP, and CAISO. Given the limited information about initial cost estimates for incumbent TO projects in NYISO, Concentric did not attempt to produce estimates for NYISO (consistent with Brattle).

ISO-NE

As noted above, the Brattle Report relied on the ISO-NE RSP cost tracking database for three of the 14 incumbent TO projects the report based its 70% cost escalation estimate on (Scobie-Tewksbury, Wakefield-Woburn, and Mystic Woburn).[99] Concentric was able to validate these estimates for the 3 projects that relied on the RSP database, but was unable to validate the Brattle Report's cost escalation estimates for the remaining 11 projects. As noted above, we believe the report inappropriately compared final project costs to early planning-level estimates that were developed before the scope of each project had been defined. For the 11 remaining ISO-NE projects, the Brattle Report relied on a February 2015 NextEra presentation for initial and final project cost figures.[100] Concentric analyzed the siting board decisions to determine the incumbent TO's initial project cost estimates and a February 2015 Eversource and National Grid presentation that responded to the NextEra presentation.[101] For example, the final siting approval order for National Grid's Worcester Reliability project included a range of cost estimates that varied depending on the project route and whether the new transmission lines would be overhead or underground. The lowest cost estimate National Grid provided for the Worcester project was $33.53 million based on a single overhead line and the highest estimate was $70+ million based on two underground lines.[102] In an effort to be conservative and permit the greatest "cost escalation", Concentric's analysis in Table 2 used the lowest cost estimate ($34 million) for the Worcester Reliability project. As shown in Table 2, Brattle used a $7 million initial cost estimate for the Worcester project which resulted in Brattle estimating a 377% escalation – 355% if adjusted for inflation – for this project, compared to Concentric's estimate of 2%. Using the same approach for the Greater Springfield project, the estimated project cost in the September 2010 siting approval for this project was $714.2 million,[103] but the

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99 Specifically, the Scobie-Tewksbury, Wakefield-Woburn, and Mystic Woburn projects, which the Brattle Report obtained initial and updated cost estimate data from the March 2018 RSP tracking database. See Brattle Report, Figure 25, p. 57.

100 NextEra Energy Transmission, *Greater Boston Cost Comparison*, January, 2015, *available at* https://www.iso-ne.com/static-assets/documents/2015/02/a2_nht_greater_boston_cost_analysis_public.pdf. *See also* Brattle Report, Figure 25, p. 57.

101 National Grid and Eversource, Response to NHT Cost Claims on Selected Projects. February 2015, available at https://www.iso-ne.com/static-assets/documents/2015/02/a2_ngrid_eversource_response_to_nht_greater_boston_cost_claims.pdf.

102 Worcester Reliability project siting board approval, Commonwealth of Massachusetts Energy Facilities Siting Board, Final Decision, Docket Nos. EFSB 09-1, D.P.U. 09-52, and D.P.U. 09-53 (March 11, 2011), Table 2, p. 18.

103 Greater Springfield siting board approval, Commonwealth of Massachusetts Energy Facilities, Final Decision, Docket Nos. EFSB 08-2, D.P.U. 08-105, and D.P.U. 08-106 (September 28, 2010), p. 82.

Brattle Report assumed a $350 million initial cost estimate.[104] The inflation-adjusted installed cost of the Greater Springfield was $676 million. Given the different initial estimates for the Greater Springfield project, the Brattle Report estimates a 117% escalation and Concentric estimates a -5% escalation. Table 14 below compares the Concentric and Brattle estimates of the cost escalations of the 11 projects.

Table 14: Analysis of Brattle Report Estimate of ISO-NE Project Cost Escalations

	Brattle Initial TO Cost Estimate ($ million)	Concentric Initial TO Cost Estimate ($million)	Installed Cost ($million)	Brattle Cost Escalation Estimate	Concentric Cost Escalation Estimate
Stoughton Cable	$213	$213	$317	49%	49%
Southwest Connecticut	$690	$993	$1,274	105%	28%
Norwalk Reliability	$128	$128	$234	83%	83%
Worcester Reliability	$7	$34	$34	377%	2%
Lower SEMA	$107	$107	$105	-2%	-2%
Millstone DCT Elimination	$22	$27	$39	76%	42%
NEEWS – Greater Springfield	$350	$714	$676	117%	-5%
NEEWS – Rhode Island Reliability	$150	$264	$330	110%	25%
Merrimack Valley/North Shore Salem Cables	$43	$62	$63	45%	1%
NEEWS – Interstate Reliability	$400	$542	$542	35%	0%
Stamford Reliability	$49	$47	$37	-15%	-21%

Source: Brattle Estimates: Brattle Report, Figure 25, p. 57. Concentric Estimates: See research above in Appendix A.

MISO

Brattle estimates that the costs of MISO's incumbent TO projects have increased by 18% for the 2015-2018 planning cycles. Because Concentric could not replicate the figures shown in Brattle's Figure 21, we are unable to review Brattle's methodology. However, Concentric reviewed the same publicly available transmission project cost data relied upon by Brattle, which shows that cost escalations ranged from 0.5% to 7.3%, far lower than the Brattle Report estimate.

[104] Brattle Report, Figure 25, p. 57.

Table 15: MISO Project Cost Change Estimates

	Initial ($million)		In-Service ($million)		% Change
MTEP 2014	$	9,085	$	9,747	7.3%
MTEP 2015		7,292		7,615	4.4%
MTEP 2016		6,304		6,675	5.9%
MTEP 2017		478		480	0.5%
Total	**$**	**23,159**	**$**	**24,517**	**5.9%**

Concentric reviewed the change between initial estimates and in-service costs for projects approved in the 2014-2017 MISO Transmission Expansion Plans ("MTEP"). Concentric examined the MTEP Appendix AB Projects List from each of the 2014, 2015, 2016, and 2017 MTEP planning cycles.[105] Concentric understands these tracking files represent projects that have been approved by MISO in a given planning cycle. The MTEP quarterly tracking reports, in contrast, represent updates to *some* project cost estimates, if they are known. The quarterly tracking reports therefore do not necessarily provide a complete cost status in any given quarter.

Concentric used MISO's "MTEP In Service Projects" list[106] for final cost estimates. This In-Service Projects list was updated by MISO as of April 29, 2019 at the time of Concentric's analysis. Concentric then compared the total project dollars approved in each of the MTEP 2014-2017 planning cycles to those projects' final in-service costs, to the extent they had been placed in service and reported to MISO as of 4/29/2019. Concentric excluded any projects for which there was no cost estimate, or a zero-dollar cost estimate, for either the initial or the final project costs. This analysis includes projects that had estimates provided in multiple MTEP Appendix AB tracking reports. As shown in Table 15, these projects have experienced a 6% cost escalation.

Finally, Concentric notes that the MISO data can be more difficult to track than other ISO/RTOs. For example, Concentric notes an Entergy Lake Charles Transmission Project had a project cost of $28 million as listed in the 2015 MTEP quarterly tracking reports, but is listed in the 2018 MTEP quarterly tracking reports with a project cost of $181 million for a perceived cost escalation of nearly 550%. Upon closer review, the approval for Entergy's Certificate of Public Convenience and Necessity ("CPCN") notes that the Company's actual initial cost estimate was $187 million.[107] In addition, it is apparent that project cost estimates in the MTEP Appendices are not listed in consistent dollar year terms, nor are they reported with consistent levels of estimation confidence (i.e., some projects list planning level estimates while others list engineering level estimates).

105 Concentric examined total projects, as opposed to individual facilities, of which there can be many under a given project's heading. Projects placed in-service indicate that all facilities are in service for the listed project.

106 https://www.misoenergy.org/planning/planning-test/mtep-quarterly-status-reports/#t=10&p=0&s=&sd=

107 Louisiana Public Service Commission, Order No. U-33645, December 16, 2015, p. 3.

PJM

The Brattle Report claims that Supplemental Projects in PJM are not tracked by the PJM Transmission Construction Status Database.[108] However, Supplemental Projects are tracked in the PJM Transmission Cost Allocation Database, which contains both initial and "latest cost estimates" for these projects.[109] The Concentric estimates thus include project cost tracking data for Supplemental Projects as well.

SPP

Brattle estimates that the costs of SPP's incumbent TO projects developed from 2009 through 2019 experienced cost escalations of 18%. Concentric determined that this estimate is significantly overstated. Table 16 shows the Brattle Report's cost escalation estimates for Balanced Portfolio Projects, Priority Projects, and ITP Portfolio Projects in SPP. In total, the Brattle Report claims that costs have increased from $2,028 million to $2,391 million (without controlling for inflation), for a total cost escalation of 18%. However, upon closer review of each category of projects using the same data sources, Concentric has determined an overall cost escalation of -2%.

Table 16: SPP Incumbent TO Project Cost Estimates

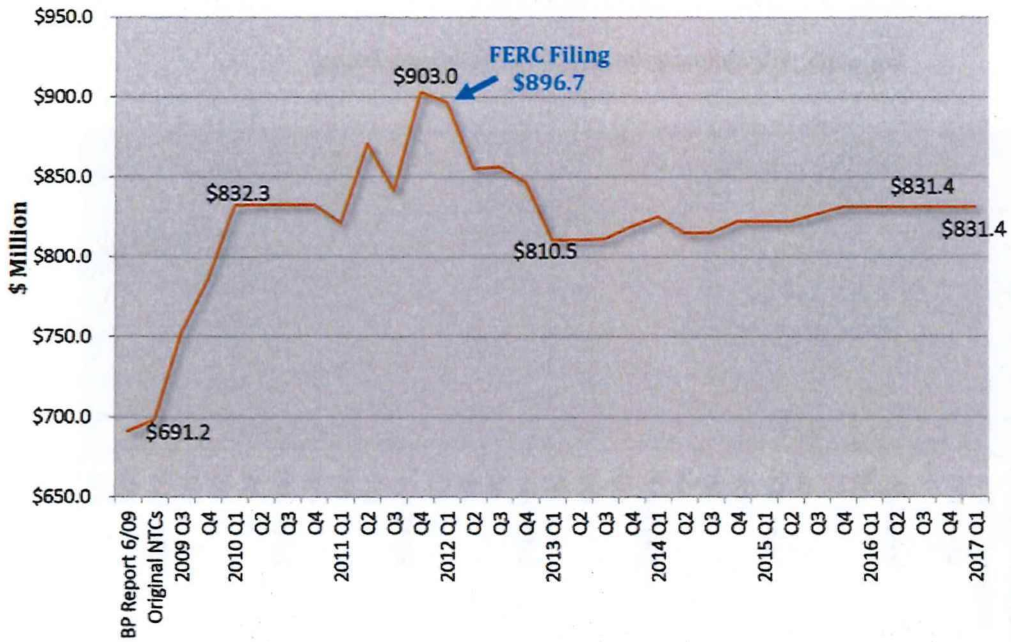
SPP Portfolio	Brattle Initial TO Cost Estimate ($ million)	CEA Initial TO Cost Estimate ($ million)	Latest Cost Estimate ($ million)	Brattle Estimated Cost Escalation	CEA Estimated Cost Escalation	# of Projects
Balanced Portfolio	$691	$832	$831	20%	0%	
Priority Projects	$1,145	$1,416	$1,349	18%	-5%	
ITP Portfolio Projects with Final Cost Estimates (2012 to 2017)	$192		$211	10%		42
ITP Portfolio Projects Listed as Complete (2012 to 2017)		$1,349	$1,330		-1%	150
Brattle Total Comparison	$2,028		$2,391	18%		
Concentric Total Comparison		$3,597	$3,510		-2%	

108 Brattle Report, p. 56. See notes in Figure 24.
109 *See e.g.*, https://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view.aspx

Balanced Portfolio Projects

Brattle relied on the 2017 Q2 SPP Quarterly Tracking Report to estimate the historical cost escalations of Balanced Portfolio Projects. These projects were part of an SPP initiative "to develop a group of economic transmission upgrades that benefit the entire SPP region and allocate those project costs regionally."[110] The figure below reports how estimates of the cost of this portfolio of projects have evolved over the 2009-2017 period.

Figure 4: SPP Balanced Portfolio Cost Estimate Trend



Source: SPP 2017 Q2 Quarterly Project Tracking Report, p. 12

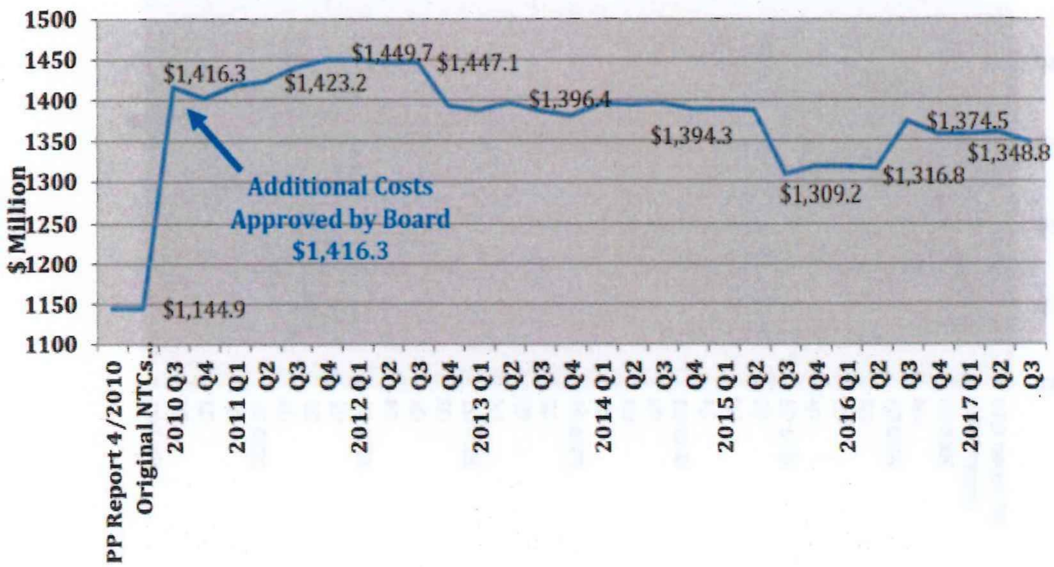
As shown in Figure 4, within 6 months of the original estimate, the cost estimate for the portfolio of Balanced Portfolio projects was revised upward by nearly $150 million. This increase was due to changes that SPP directed to promote a more consistent extra high voltage planning design.[111] This is an example of how estimates change significantly if the scope changes. Concentric believes the cost estimate from 2010 Q1 is a more accurate starting point from which to measure cost increases or decreases because the projects were re-scoped in the intervening months. The result is a 0% cost escalation figure for Balanced Portfolio Projects.

110 SPP 2017 Q2 Quarterly Project Tracking Report, p. 12.
111 SPP 2010 Q1 Quarterly Project Tracking Report, p. 2.

Priority Projects

Brattle relies on the 2017-Q4 SPP Quarterly Tracking Report to represent the cost escalations of Priority Projects. These projects were approved as "priority" high voltage electric transmission projects with large estimated regional benefits. As seen in Figure 5, within six months of the original cost estimates, SPP approved additional costs "due to line rerouting and addition costs for reactive compensation."[112] These types of adjustments could occur with any transmission project, regardless of its developer or the process by which it is selected. The total cost estimate for the SPP Priority Projects after the variances were approved was $1.42 billion.

Figure 5: SPP Priority Project Cost Estimate Trend



SPP 2017 Q4 Quarterly Project Tracking Report, p. 12.

Given the scope changes directed by SPP, Concentric believes the second reported data point is a more accurate starting point from which to measure cost increase or decreases. This results in a -5% cost escalation for Priority Projects.

ITP Portfolio Projects

Brattle relies on the 2019 Q1 SPP Quarterly Tracking Report, Appendix 1 data to represent the cost escalations of ITP Portfolio Projects. Concentric examined the 2019 Q1 tracking data and determined that Brattle did not consider the full sample of completed projects. This means Brattle has filtered the tracking data and only considered 42 projects, excluding over 100 completed projects. In our view, including the larger sample of projects is reasonable as the ultimate project costs are largely known. Including these projects also expands

112 SPP 2017 Q4 Quarterly Project Tracking Report, p. 12.

the project sample size from 42 to 150, which is more broadly representative of the portfolio of projects completed in SPP during the timeframe Brattle considered (2012-2017) and increases the total value of the transmission projects in the sample from $192 to $1,349 million. The change in costs between the initial estimate to the latest cost estimate tracked by SPP is -1%.

In summary, Concentric has examined each of the SPP documents the Brattle Report referenced to better understand these claims. Upon review, Concentric can determine that the Brattle Report's SPP estimates are significantly overstated, and do not necessarily provide the full context of how transmission project costs have evolved in SPP.

CAISO

Figure 23 of the Brattle Report presents estimates of the "historical cost escalation" of incumbent TO projects in CAISO. Figure 23 examines 18 transmission projects and notes that the projects are "not the complete universe of CAISO projects".[113] Figure 23 states that in aggregate, final costs of 18 projects exceeded initial estimates by 33%. However, Figure 23 also states that CAISO only published initial cost estimates for 10 of these projects (the other initial cost estimate data for the other projects was provided to the California Public Utilities Commission). The Brattle Report only used the 10 projects that also had CAISO estimates to calculate CAISO incumbent TO historical cost escalation, which the report estimated was 41%.[114] Limiting this already small sample of projects from 18 to 10 increased the estimated historical cost escalation in CAISO from 33% to 41%.

Concentric reviewed the same sources the Brattle Report cited in Figure 23 to assess the CAISO estimate and determined that the 41% cost escalation estimate is highly sensitive to the sample of projects selected. However, as noted above, we caution that this sample of projects is too small and unrepresentative to constitute a reasonable estimate of how final and/or updated project costs compare to initial incumbent TO estimates in CAISO. Nevertheless, we conducted our analysis to assess the reasonableness and accuracy of the Brattle Report's CAISO estimate.

1. <u>PG&E</u>

Concentric reviewed information about PG&E's initial and final project costs that was available in the FERC dockets referenced in the Brattle Report. Rather than limit the analysis to a subset of projects with initial and final cost estimates, Concentric analyzed all of the PG&E projects that had initial and final project cost information that was available in the FERC dockets referenced in Figure 23 of the report (Docket Nos. ER16-2320-000 and EL17-45-000). Concentric expanded the PG&E sample in two ways. First, the Brattle Report only relies on seven of the eight PG&E projects referenced in FERC Docket No. ER16-2320 while the Concentric

113 Brattle Report, Figure 23, p. 55.
114 Brattle Report, Figure 23, p. 55, at column 6.

analysis included all eight projects.[115] Second, Concentric included initial and final project cost information for 47 additional PG&E transmission projects (Substation and Line Capacity projects) that PG&E provided in response to a California Public Utilities Commission ("CPUC") data request.[116]

As shown in Table 17 below, expanding the sample results in a PG&E cost escalation estimate ranging from 6.1% to 18.8%. In total, this portfolio of PG&E projects experienced an "average" cost overrun of 12.6%. Concentric uses the initial estimates that PG&E provided to CAISO and not the "CAISO estimate" that the Brattle Report used, as such the figures are comparable to column 5 in Figure 23 of the report.

Table 17: Concentric review of Brattle's Historical Cost Escalation Estimate for PG&E

	CAISO Approved Cost ($)		Final or Updated Cost ($)
Docket No. EL17-45-000 projects	Low	High	
-Substation Capacity	358,499	485,899	339,842
-Line Capacity	317,600	373,600	437,246
Total	676,099	859,499	777,088
Docket No. EL16-47-000 projects	858,600	858,600	1,046,408
Total Estimate	1,534,699	1,718,099	1,823,496
Final or Updated - CAISO Approved ($)	288,797	105,397	
Final or Updated - CAISO Approved (%)	18.8%	6.1%	

Docket No. EL16-47-000 Projects: Exhibit CPUC-001, Prepared Direct Testimony of Geneva Looker, Docket No. ER16-23-20-000, p. 24, Table J (filed July 5, 2017). Docket EL17-45-000 Projects: California Parties v. Pacific Gas and Electric Co., (filed Feb. 2, 2017) Docket No EL17-45-000, Exhibit 2 - PG&E Response to CPUC Data Request, pp 4-6.

2. SDG&E

To estimate average historical cost escalations for SDG&E, Brattle Report relied on initial and updated project cost estimates that SDG&E provided to the CPUC. However, rather than use information for all 17 of the projects supplied, Brattle excluded seven projects in column 5 of Figure 23, without explanation, and estimated an average cost escalation of 19.7% for SDG&E. Brattle then limited the sample further to 3 projects with a "CAISO estimate" (column 3 of Figure 23), which results in an estimated escalation of 2.3% for the 3 projects. If Brattle had used all 17 projects, the average cost escalation would be 5.9% as demonstrated by Concentric. Although the sample of 17 is still limited and not necessarily representative of SDG&E's overall portfolio of projects, it provides a better estimate than the three SDG&E projects the Brattle Report used to estimate historical cost escalation in CAISO.

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115 Exhibit CPUC-001, Prepared Direct Testimony of Geneva Looker, Docket No. ER16-23-20-000, p. 24, Table J (filed July 5, 2017). Table J references Docket No. EL16-47-000, where PG&E sought abandoned plant recovery for certain transmission projects. The Brattle Report sample for PG&E excluded a project that had final costs that were below PG&E's initial estimate.

116 This information was included as an Exhibit to a February 2017 complaint filed at FERC (Docket No. EL17-45-000). *See California Parties v. Pacific Gas and Electric Co.*, (filed Feb. 2, 2017) Docket No EL17-45-000, Exhibit 2 - PG&E Response to CPUC Data Request, pp. 4-6.

It warrants mention that most of SDG&E's final project costs were below the initial cost estimates. One project - the East County ("ECO") Substation project referenced in Figure 23 of the Brattle Report - experienced significant cost overruns due to an unplanned routing change directed by the CPUC. During the permitting process, the CPUC required undergrounding a portion of the line. As a result, the final project cost for the ECO Substation was $410 million, a 50% increase above the initial cost of estimate $273 million.[117] We note this to reiterate that greenfield transmission projects face significant cost risks due to factors beyond the developer's control, such as regulatory siting and permitting issues.

Table 18: Sample of SDG&E Transmission Projects completeed Jan. 2014 – Nov. 2016

	Initial Project Cost Estimate ($)	Final Project Cost ($)	Difference ($)	%
TL 637 CRE-ST SW Pole Replacements	45,000,000	39,570,571	-5,429,429	-12.1%
Mira Sorrento 138/12KV Sub & Cirs. 1442 Thru 1446	50,300,000	18,733,717	-31,566,283	-62.8%
ECO Substation	273,000,000	409,839,624	136,839,624	50.1%
Poseidon Project-Modify Cannon Sub & Install 2 Ckts	14,500,000	11,332,962	-3,167,038	-21.8%
New TL ES-Ash #2	21,600,000	4,661,923	-16,938,077	-78.4%
IV West Generator Interconnection (Q608)	2,114,000	1,114,439	-999,561	-47.3%
TL694A Melrose Loop-In Project	41,363,000	33,788,430	-7,574,570	-18.3%
TL6914 Los Coches-Loveland SW Pole Replace	40,000,000	23,929,019	-16,070,981	-40.2%
Talega-Add Synchronous Condensers	64,400,000	80,840,653	16,440,653	25.5%
Shunt Reactor on Suncrest 500kV Bus	10,900,000	9,834,023	-1,065,977	-9.8%
Sunnyside 69/12kV Rebuild	16446000	9,780,217	-6,665,783	-40.5%
Pio Pico Energy Ctr.	9,422,000	9,584,640	162,640	1.7%
Wabash Substation Rebuild	6,100,000	9,777,332	3,677,332	60.3%
Relocate South Bay Substation	129,200,000	120,732,727	-8,467,273	-6.6%
Talega Bank 50 Replacement	5,500,000	2,138,852	-3,361,148	-61.1%
TL13821 and TL13828-Fanita Junction Enhancement	41,400,000	35,318,965	-6,081,035	-14.7%
Encina Bank 61	11,156,000	7,873,169	-3,282,831	-29.4%
Full sample (17 projects)	782,401,000	828,851,263	46,450,263	5.9%
Brattle sample (10 projects)	568,692,000	680,824,576	112,132,576	19.7%

Source: California Parties Complaint, filed Feb. 2, 2019 in Docket No. EL17-45-000, Exhibit 3, page 7.
*SDG&E indicated that this cost estimate was provided at the time the project first appeared on the AB970 report to the CPUC.

[117] *See e.g.*, CPUC proceeding for SDG&E CPCN application for the East County Substation (Application A.09-08-003).

3. SCE

The Brattle Report did not use any Southern California Edison (SCE) projects to estimate historical cost escalation of CAISO incumbent TO projects despite the fact that SCE is the second largest incumbent in CAISO. However, Figure 23 of the Brattle Report references a single project – the Tehachapi project that was completed in 2014. The Tehachapi project constitutes another example of the fact that transmission projects, particularly projects that require a new CPCN, face risks that are beyond the developer's control.[118] The Tehachapi project was a complex greenfield project and, as a result, faced significant and unexpected citing issues that other projects (e.g., upgrades don't typically require a CPCN) are unlikely to face. As such, the cost escalation experienced in the Tehachapi is not representative of the risk that the full portfolio of SCE projects will face.

The Tehachapi project was a large greenfield project designed to interconnect approximately 4,500 MW of generation capacity to the SCE system. Construction was split into 11 segments. SCE's preliminary cost estimate for segments 4-11 of the Tehachapi project was $1.72 billion (in 2009 dollars).[119] In December 2009, the CPUC issued a CPCN for these segments, which included an overhead route in the City of Chino Hills, California area (segment 8A). However, parties in the Chino Hills areas sought rehearing of this decision regarding segment 8A and in January 2010, 22 months after issuing the initial CPCN, the CPUC issued a stay on the construction of segment 8A, and SCE ceased construction activities on that segment, despite the fact that segment 8A was almost completed in an overhead configuration. In July 2013, the CPUC reversed its initial December 2009 decision of the CPCN for segment 8A and directed SCE to construct about 3.5 miles of segment 8A in the Chino Hills area underground. SCE also had to remove newly constructed overhead transmission structures and substation facilities it had constructed in accordance with the initial 2009 CPCN for the segment.[120] In 2014, FERC granted SCE's request to recover $14.445 million in abandoned plant to recover the costs of project support, engineering, environmental monitoring, and mitigation activities; direct material and construction costs; removal activity; and certain overheads associated with these expenditures.[121]

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118 See e.g., *Southern California Edison Company*, Order on Abandonment Cost Recovery Filing, 148 FERC ¶ 61,126 at PP 2-7 (Aug. 15, 2014).

119 Southern California Edison, Certificate of Public Convenience and Necessity Concerning the Tehachapi Renewable Transmission Project (Segments 4 through 11), Opening Brief, Application No. 07-06-031 (June 28, 2007), at *ix*. This estimate excludes Allowance for Funds Used During Construction.

120 *Southern California Edison Company*, Order on Abandonment Cost Recovery Filing, 148 FERC ¶ 61,126 at PP 2-7 (Aug. 15, 2014).

121 *Southern California Edison Company*, Order on Abandonment Cost Recovery Filing, 148 FERC ¶ 61,126 at P 10. (Aug. 15, 2014). Specifically, the $14.445 figure includes This amount includes: (1) $11.667 million in direct expenditures for construction of the overhead structures and substation, facilities that are now abandoned; (2) $3.595 million in costs for the removal of the overhead facilities; and (3) $38,000 in additional expected removal costs. SCE reduced its overall expenditures by $645,000 for reusable structures and by $210,000 for salvageable items.

APPENDIX B: ESTIMATING TRANSMISSION PROJECT COSTS

Estimating the cost of transmission projects is an inherently difficult task, as is the case with any large capital project. Most large transmission projects face risks to schedules and budgets at every step—from feasibility, siting, permitting and design to construction and operation. While there are many factors that can impact schedule and budget, they generally fall into three categories: i) economic and commercial risks; ii) regulatory issues; and iii) public opposition. Together, all of these elements have the potential to significantly impact project costs by altering project scope, prolonging project timelines and adding uncertainty to already complex financing processes, contributing to cost variances from the preliminary budget estimate.

Economic and commercial considerations are a fundamental part of the justification or rationale for planning and constructing a transmission project. Transmission planning often involves a host of economic assumptions and supporting analytic activities to demonstrate that a project is warranted. All economic and commercial considerations and associated cost forecasts are anchored to the time when they are made. As time passes, the assumptions upon which these considerations rest can change. For example, the price of steel may fall (or rise) between the time a project is conceived and the time it is built. In some instances, for example if the project is not needed for reliability, these changes may be so large that they undermine the economic or commercial viability of the project, and the project may be cancelled. The long lead times associated with development of transmission projects increases their exposure to these factors.

In addition, regulatory risks can threaten project budgets and schedules. States generally hold authority to issue a CPCN for construction and operation of a transmission line; this authority is most frequently under the jurisdiction of a state public utility commission. A CPCN is typically required for a transmission developer to construct facilities to transport electricity at transmission (and sometimes lower, sub-transmission) voltages within a state's borders. Issuance of a CPCN is based on a finding by the state authority that the proposed project is in the public interest. The public interest standard is typically measured by assessing the cost incurred by ratepayers against the expected economic impacts of a project within the state. For projects that involve more than one state, differences among the involved states' CPCN policies and processes must also be addressed. The risk of protracted regulatory processes to assess the public benefit of proposed transmission construction can threaten both cost and schedule estimates.

Finally, public opposition can play a significant role in a developer's ability to meet project cost thresholds and schedule milestones. Organized public opposition to proposed transmission lines has frequently had a material impact on project development by adding time to siting and routing processes, and it has sometimes led or contributed to the cancellation of projects or to the addition of mitigation measures that have increased the project developers' costs. For example, as described in Section 2, many of the projects Brattle used to estimate cost escalations in ISO-NE experienced such issues. Project developers frequently attempt to reduce these costs and associated time requirements through up-front information sharing and joint (and early) development of mitigation approaches. The success of these activities has hinged largely on the extent to which they lead to meaningful engagement and tangible commitments to address public concerns over line routing. For transmission line projects involving federal lands, compliance with the National Environmental Policy Act ("NEPA") involves a sequence of open processes: scoping meetings, public reviews of both a draft and final EIS, and issuance of a Record of Decision. Because of their geographic scope, multi-state transmission projects can entail coordination among more than one federal agency, multiple state offices, and also related state, tribal, and local agencies during the approval process. Approval processes involving multiple agencies raise many institutional issues that sometimes result in significant mitigation costs and time requirements to obtain final approval for a route involving non-private lands.

A good example of the impact these factors can have on schedule and budget was demonstrated in Texas. The Competitive Renewable Energy Zones ("CREZ") initiative was a multiyear effort to connect wind from West Texas to cities in the eastern part of the state that demanded more power. The new transmission projects cost Texas ratepayers over $6.8 billion, far higher than the $4.9 billion projection in 2008.[122] Inflation drove some of the increase. However, the increased scope of the project was a bigger factor. In calculating the original estimate, early cost estimates assumed the transmission lines would follow the most direct routes. As the process played out, however, regulators minimized intrusion by redrawing the routes to follow fences or roads. Those decisions added more than 600 miles of power lines that weren't originally planned.

In addition to the factors impacting the cost and schedule of transmission build noted above, the process used to develop the cost estimate does not lend itself to accurate cost variation analysis. First, many of the initial cost estimates, on which variances are frequently measured, are based on planning level information. These conceptual estimates often lack detailed engineering or design detail and are typically prepared from historical data and used for screening purposes only. However, as discussed further below, the precision of the ISOs/RTOs initial cost estimates, often measured by a percentage confidence level, varies.

For example, in SPP, once a project passes the conceptual screening criteria, a study estimate is prepared that is a more refined estimate of the cost of the transmission project. This project estimate often establishes the baseline for the project cost variance going forward. According to the SPP cost estimate guidelines, the project development stage has a direct impact on the precision of the cost estimate as shown in Table 1 below.

122 *See e.g.*, The Texas Tribune, *$7 Billion Wind Power Project Nears Finish*, October 13, 2013, available at https://www.texastribune.org/2013/10/14/7-billion-crez-project-nears-finish-aiding-wind-po/

Table 19: Southwest Power Pool Cost Estimate Stage Definition

Estimate Name	Level of Project Scope Definition	Precision Bandwidth
Conceptual	0% - 10%	-50% to +100%
Study	10% - 20%	-30% to +30%
Conditional Notification to Construct or Notification to Construct	20% - 40%	-20% to +20%
Design and Construction	40% - 100%	-20% to +20%

Source: SPP Cost Estimates Presentation, Katherine Prewitt, May 2011.

The precision of the cost estimate increases as the project progresses from the concept and study phase to the design and construction phase. The project's cost estimates become more precise as the developer acquires more information about the specifications of the project and updates the estimates accordingly. For example, equipment cost estimates become more precise after the developer learns more about the specific technical needs of new equipment. It is common practice to obtain multiple quotes for various project components. For a greenfield transmission project, better information on the route allows a developer to get a better sense of the construction costs and the equipment required to construct the project.

MISO uses different definitions for the various estimates it instructs developers to produce for cost tracking purposes. Table 20 shows that the precision of project estimates increase over time as more information becomes available, shown in the table as an increase in the "maturity level of project definition deliverables".

Table 20: MISO Cost Estimate Stage Definition

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

Source: MISO, Transmission Cost Estimation Guide – MTEP19, March 9, 2019, p. 4. Note: MISO described the different types of project cost estimates as follows: Class 3: MISO scoping cost estimate; and Class 4: MISO planning-cost estimate; Class 5: MISO exploratory cost estimate.

It is important to note that the category of estimates shown in the table above do not include any contingency amounts. Contingency is added to a project estimate to allow for uncertain or unexpected events which will likely result in additional costs. Contingency for transmission projects can range from approximately 5% to 50% of total construction costs, and contingency amounts tend to be highest during the early stages of a project's development process. In addition to the improper comparison of different types of cost estimates, e.g., use of a baseline cost estimate, other factors can lead to perceived cost variances that are only due to inflation, a cost escalating factor that the Brattle Report also notes.

APPENDIX C: ORDER NO. 1000 SOLICITATION DETAILS

This appendix describes the transmission solicitations reviewed in the report in more detail. As of the writing of this report, solicitations have been carried out through the ISO/RTO regional transmission planning processes in CAISO, MISO, NYISO, PJM, NYISO, and SPP, and these solicitations are discussed in turn in the remainder of this appendix.

CAISO

As of the writing of this report, the California ISO (CAISO) has had ten solicitations, but the last solicitation occurred in 2015. After CAISO selects a winning proposal from a solicitation, it executes an Approved Project Sponsor Agreement ("APSA") that specifies, among other things, the project's capital cost, operating and maintenance, and other terms the project developer included in its proposal that affect the annual transmission revenue requirement associated with the project. Below is a summary table of Concentric's research to recreate the figures in the Brattle table that purportedly summarized the cost savings associated with competitive transmission solicitations in CAISO. Concentric was only able to locate the APSAs of seven of the CAISO solicitations. Specifically, Concentric was not able to locate the costs of the bids of three projects of CAISO investor-owned utilities PG&E and SDG&E.

Concentric determined that the "cost savings" estimates for CAISO in figure 18 of the Brattle Report compare a CAISO planning-level estimate with the winning bid. The table below summarizes Concentric's recreation of the CAISO figure in Figure 12 of the Brattle Report. If the CAISO planning estimate was a range, Brattle used the high end of the range to calculate the savings in Figure 18, which maximized the estimated savings. Concentric recreated the $1,180 million figure Brattle used as the "RTO/ISO Incumbent estimate of project cost" figure for total planning estimate costs but not the $833 million figure given we could not identify APSAs for the Wheeler Ridge, Spring, and Miguel substations

Table 21: Summary of CAISO Transmission Solicitations

Project	Winning Bid	CAISO Planning Estimate ($ million)	Project Cost in Approved Sponsor Agreement ($)	Winning Bid vs. High CAISO Planning Estimate (low-high%)
Gates-Gregg (delayed)	PG&E /MidAmerican	115 - 145	157,021,766	-8 - 37%
Imperial Valley Element	Imperial Irr. Dist.	25	14,283,122	-43%
Sycamore – Penasquitos	SDG&E	111 - 221	129,975,759	-41% -17%
Delaney to Colorado River	DCR Transmission	-300	241,805,391	-19%
Estrella	NextEra	35 – 45	24,539,000	-30 – -45%
Wheeler Ridge	PG&E	90 – 140	Unknown	
Suncrest	Next Era	50 – 75	42,288,000	-44% – -15%
Spring Sbstn. Morgan Hill	PG&E	35 – 45	Unknown	
Harry Allen to Eldorado	DessertLink	144,000,000	147,000,000	2%
Miguel	SDG&E	30 – 40	Unknown	
Total	Range	$935-1,820		
	Average	$1,058		
Brattle figure for winning bids			$833,000,000	
Total winning bids w\out Wheeler, Spring, and Miguel			$756,913,038	
Avg. "savings" w\out Wheeler, Spring, and Miguel			3-26%	

Suncrest

Project Type: Policy[123]

Project detail: 300 MVAr dynamic reactive power support element connecting to the Suncrest 230 kV bus. SVC or synchronous condenser

Bid window: April 16, 2014 - June 16, 2014[124]

Bidders:

- NextEra Energy Transmission West, LLC ("NEET West")
- San Diego Gas and Electric Company

Winner: NEET West, who offered a project construction cost cap of $42,288,000 in 2015 dollars, with operation and maintenance costs for the first five years of operation capped at $360,000 per year. NEET West signed an APSA with CAISO on May 7, 2015.[125]

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

124 CASIO, Suncrest Valley List of Validated Project Sponsor Applications with Sufficient Information, August 5, 2015, p. 1.

125 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.

ISO Implementation Cost: $260,572[126]

ISO Project Cost Estimate: $50 - 75 million, produced April 2014.[127]

Delaney to Colorado River
Project detail: New 500 kV transmission line and associated series compensation between Delaney Substation and Colorado River Substation. Only the 500 kV transmission line and series compensation were eligible for solicitation. The facilities necessary at Delaney Substation and Colorado River Substation to interconnect with the project, including anticipated shunt reactors, were not eligible for solicitation per the CAISO tariff.[128]

Bid window: August 19, 2014-November 19, 2014[129]

Bidders:[130]

- DCR Transmission, LLC (A joint venture between Abengoa Transmission & Infrastructure and an affiliate of Starwood Energy Group Global, Inc.)
- California Transmission Development LLC (a wholly owned subsidiary of LS Power & Associates)
- Duke-American Transmission Company LLC, in collaboration with Western Area Power Administration Desert Southwest Region, and Citizens Energy Corporation.
- NextEra Energy Transmission West LLC (a wholly owned subsidiary of NextEra Energy Transmission)
- TransCanyon DCR LLC in collaboration with Southern California Edison

Winner: DCR Transmission, LLC. According to CPCN filed with CPUC for the "Ten West", the APSA had a cost cap of $ 241,805,391 and was signed December 1, 2015.[131] Updated project cost estimates were $279,560,483 in 2020, provided in October 2016.[132]

ISO Project Cost Estimate: $300 million in 2014 dollars, produced July 2014[133]

Expected In-Service Date: May 1, 2020

ISO Implementation Cost: $530,359[134]

Estrella Project
Need: reliability

126 CAISO, Summary of Accrued Project Sponsor Costs – Suncrest, March 20, 2015, p. 1.
127 CAISO, Suncrest 230 kV 300 MVAr Dynamic Reactive Power Support Description and Functional Specifications for Competitive Solicitation, April 15, 2014, p. 2.
128 CAISO, Delaney to Colorado River Project Sponsor Selection Report, July 10, 2015, at 2.
129 CAISO, Delaney to Colorado River Project Sponsor Selection Report, July 10, 2015, at 2 p. 2.
130 CAISO, Delaney to Colorado River Project Sponsor Selection Report, July 10, 2015, at 3.
131 DCR Transmission, Application for a Certificate of Public Convenience and Necessity for Ten West Link Project, Application A.1610-012, Appendix N, Approved Project Sponsor Agreement, October 12, 2016, p. 45.
132 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.
133 CAISO, Delaney to Colorado River 500 kV Transmission Line Project Description, Key Selection Factors, and Functional Specifications for Competitive Solicitation, July 2014, p. 2.
134 CAISO, Delaney to Colorado River 500 kV Transmission Line, Summary of Accrued Project Sponsor Costs, Updated December 7,

Project detail: new 230/70 kV substation approximately five miles east of the existing Paso Robles substation. Reliability-driven need to reinforce the 70 kV system to increase the reliability and mitigate thermal overloads and voltage concerns in the Templeton and Estrella areas. The Estrella Project includes a 230/70/12 kV substation, Estrella Substation, new 230/70kV and 230/12 kV transformers, and reconductoring and looping the existing transmission lines. Only the 230/70 kV transformer, 230 kV switchyard, and 230 kV termination structures were eligible for solicitation. The 230/12 kV transformer, 70 kV bus work and termination equipment, and modifications to existing facilities were not eligible for solicitation under the CAISO Tariff.[135]

Bid window: April 16, 2014 – August 18, 2014

Bidders:[136]

- Brookfield California Transmission, LLC (Brookfield CalTrans), an affiliate of Brookfield Asset Management, Inc.
- Golden State Transmission, LLC (Golden State), a joint venture company owned by Edison Transmission, LLC and Transource Energy, LLC
- NextEra Energy Transmission West, LLC ("NEET West")
- Pacific Gas and Electric Company (PG&E)

Winner: NEET West, which signed an APSA with a cost cap of $24,539,000 and a binding annual O&M cost cap for the first five years following commencement of commercial operation.[137]

ISO Implementation Cost: $206,104[138]

ISO Project Cost Estimate: both the solicitation portion and incumbent TO portions were estimated to cost between $35-$45 million.[139]

Proposed In-service Date: May 2019

Harry Allen to Eldorado
Need: economics

Project detail: new 500 kV line between SCE's 500 kV Harry Allen Substation and NV Energy's 500 kV Eldorado Substations. Approximately 60 miles in length.[140]

Bid window: January 30, 2015 - April 30, 2015.

Bidders:

135 CASIO, Estrella Project Sponsor Selection Report, March 11, 2015, p. 2.
136 CASIO, Estrella Project Sponsor Selection Report, March 11, 2015, p. 3.
137 *NextEra Energy Transmission West, LLC*, Order on Participating Transmission Owner Tariff and Rate Incentives Proposal, and Establishing Hearing and Settlement Judge Procedures, 154 FERC ¶ 61,009 (Jan. 8, 2016) at note 12.
138 CAISO, 2013-2014 Transmission Planning Process - Revised Summary of Accrued Project Sponsor Costs, November 11, 2014, p. 1.
139 CAISO, Estrella Substation Project Description and Functional Specifications for Competitive Solicitation, June 26, 2014, p. 3.
140 CAISO, Harry Allen-Eldorado 500 kV Transmission Line Project Sponsor Selection Report, January 11, 2016, pp. 2, 10.

- DesertLink, LLC ("DesertLink"), a wholly-owned subsidiary of LS Power Associates, L.P.
- Exelon Transmission Company, LLC, a wholly-owned subsidiary of Exelon Corporation
- NextEra Energy Transmission West, LLC, an affiliate of NextEra Energy, Inc., in collaboration with Southern California Edison Company (NEET West/SCE)

Winner: DesertLink

ISO Implementation Cost: $434,703[141]

ISO Project Cost Estimate: $144 million.[142]

Proposed In-Service Date: May 1, 2020

Notes on FERC Rate: 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 $147 million for the project, subject to certain conditions and exceptions. Pursuant to a settlement FERC certified in May 2018,[143] DesertLink has agreed 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.[144] Desert Link also agreed in the settlement that the transmission line will be in service by May 1, 2020, and that the transmission revenue requirement cost cap used in winning the competitive bid ($147 million) will be adhered to.

Wheeler Ridge Junction
Need: reliability

Project detail: Build a new 230/115 kV transmission substation at Wheeler Ridge Junction as well as CDWR pumps, with a more reinforced 230 kV source from Kern PP. The facilities in the Wheeler Ridge Junction substation project that are eligible for solicitation are the 230 kV bus-work and termination equipment, and the 230/115 kV transformers. The 115 kV bus-work and termination equipment and modifications to existing facilities are not eligible for solicitation. For the interconnection of the existing 230kV lines to the Wheeler Ridge Junction substation, the incumbent PTO (PG&E) was responsible to bring the new transmission line extensions up to a point within 100 feet of the new substation fence.[145]

Bidders:

- Brookfield Transmission

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141 CAISO, 2013-2014 Transmission Planning Process, Harry Allen to Eldorado 500 kV Transmission Line Summary of Accrued Project Sponsor Costs.
142 CAISO, Harry Allen-Eldorado Project Description and Functional Specifications, January 7, 2015, p. 1.
143 *Desert Link, LLC*, Certification of Uncontested Settlement, 163 FERC ¶ 63,014 (May 24, 2018).
144 Id. at P 5. See also http://www.cpuc.ca.gov/General.aspx?id=5240
145 CAISO, Wheeler Ridge Junction Substation Project Description and Functional Specifications for Competitive Solicitation, June 16, 2014, pp. 2-3.

- Golden State Transmission
- PG&E
- NextEra Energy Transmission West, LLC

Winner: PG&E

ISO Implementation Cost: $151,179[146]

ISO Project Cost Estimate: $90-140 million, including both the competitive and noncompetitive portions, to be between, produced June 2014[147]

Proposed In-Service Date: May 2020

Miguel
Need: reliability

Project detail: The reactive power support is required to provide continuous reactive power support with one of the following types of devices: SVC (Static VAR Compensator); STATCOM (Static Synchronous Compensator); or Synchronous Condenser. SDG&E will design, engineer, install, own, operate, and maintain the necessary equipment additions within Miguel substation.[148]

Bid window: April 16, 2014 - June 16, 2014

Bidder: San Diego Gas and Electric Company ("SDG&E")

Winner: SDG&E

ISO Evaluation Cost: $15,056[149]

ISO Project Cost Estimate: $30-$40 million[150]

Proposed In-Service Date: June 1, 2017. Project completed.

Spring Substation
Need: reliability

Project detail: Construct a new 230/115 kV substation, Spring Substation, west of the existing Morgan Hill Substation. Install a new 230/115 kV 420 MVA transformer at Spring Substation. Loop the existing Morgan

146 CAISO, 2013-2014 Transmission Planning Process - Revised Summary of Accrued Project Sponsor Costs, November 11, 2014, p. 2.
147 CAISO, Wheeler Ridge Junction Substation Project Description and Functional Specifications for Competitive Solicitation, June 16, 2014, p. 3.
148 CAISO, Key Selection Factors in Selection of Successful Project Sponsors Relating to the 2013-2014 Transmission Plan, May 1, 2014, p. 2.
149 CAISO, 2013-2014 Transmission Planning Process, Summary of Accrued Project Sponsor Costs - Miguel, November 11, 2014.
150 CAISO, Miguel 500 kV 375 MVAr Reactive Power Support Description and Functional Specifications for Competitive Solicitation, May 1, 2014, p. 1.

Hill-Llagas 115 kV Line into the Spring 115 kV bus using a portion of the idle Green Valley-Llagas 115 kV Line right-of-way.

Bid window: April 16, 2014 - August 18, 2014

Bidders:

- NextEra Energy Transmission West, LLC
- Brookfield California Transmission West, LLC
- Pacific Gas and Electric Company

Winner: PG&E

ISO Evaluation Cost: $165,912[151]

ISO Project Cost Estimate: $35-45 million, produced June 2014

Proposed In-service Date: May 2021[152]

Sycamore – Penasquitos
Need: policy

Project: 230 kV transmission line between SDG&E owned Sycamore and Penasquitos 230 kV substations.[153]

Bid window: April 1, 2013 - June 3, 2013

Bidders:[154]

- Abengoa T&D
- Elecnor, Inc
- SDG&E
- Trans Bay Cable LLC

Winner: SDG&E

APSA: initial: $129,975,759 (2014). Revised: $ 259,670,632 (2015)

Notes: The CAISO filed the initial APSA between SDG&E and the CAISO with FERC on August 11, 2014 in Docket No. ER14-2629-000. The CPUC issued its final certificate for the project on October 13, 2016, and it required the project to place the majority of the transmission line underground, whereas the CAISO specification assumed that the majority of the line would be placed above ground and in SDG&E's existing rights-of-way.

151 CAISO, 2013-2014 Transmission Planning Process - Revised Summary of Accrued Project Sponsor Costs, November 11, 2014, p. 1.
152 CAISO, Spring Substation Project (Morgan Hill Area) Description and Functional Specifications for Competitive Solicitation, June 26, 2014, p. 3.
153 CAISO, Sycamore-Penasquitos 230 kV Line Description and Functional Specifications Eligible for Competitive Solicitation, April 1, 2013, p. 1.
154 CAISO, Sycamore-Penasquitos Project Sponsor Selection Report, March 4, 2014, p. 4.

However, the CPUC certificate decision requires the SDG&E to underground the majority of the line, which increases the estimated cost to $260 million and extended the energization date to June 30, 2018.[155]

ISO Project Cost Estimate: $111-221 million, produced April 2013[156]

Proposed in-service date: Initial- May 2017, Revised- June 2018

Gates-Gregg

Need: Reliability

Project: The Gates-Gregg Project is a 230 kV transmission line that originates from the PG&E Gates Substation and terminates at the PG&E Gregg Substation. The Gates-Gregg Project includes the transmission line itself, all required work within the fence line of each substation is not included as part of the Gates-Gregg Project.

Window: April 1, 2013 - June 3, 2013.[157]

Bidders:[158]

- Elecnor Inc.
- Isolux Infrastructure
- PG&E and MidAmerican Transmission
- Pattern Energy Group LP and the City of Pittsburg
- G2G ProjectCo LLC (Trans Bay Cable)

Winner: PG&E and MidAmerican Transmission

Approved Sponsor Agreement: $ 157,021,766 (2013 dollars), signed August 31, 2014.

ISO Project Cost Estimate: $115 - $145 million[159]

Proposed In-service: Initially March 31, 2020, but now December 2022 per the CAISO 2017-2018 transmission plan.[160]

Notes: Per a filing on May 17, 2018 in Docket No. ER17-1628, CAISO requested an amendment to the APSA to revise the milestones so that the permitting and construction of the Gates-Gregg Project could be put on hold pending the results of the CAISO 2017-2018 transmission planning process. In reviewing the Gates-Gregg Project in the CAISO's 2016-2017 Transmission Planning Process, due to a decrease in the forecasted load the Gates-Gregg Project may no longer be needed.[161]

155 CAISO Transmittal Letter, Docket No. ER17-1627-000, May 18, 2017, pp. 1-2.
156 CAISO, Sycamore-Penasquitos 230 kV Line Description and Functional Specifications Eligible for Competitive Solicitation, April 1, 2013, p. 2.
157 CAISO Transmittal Letter, Docket No. ER14-2347-000, July 1, 2014.
158 CAISO, Gates Gregg Selection Report, p. 2.
159 CAISO, Gates-Gregg 230 kV Description and Functional Specifications for Competitive Solicitation, April 1, 2013, p. 2.
160 CAISO, 2017-18 Transmission Plan, March 22, 2018, p. 135.
161 CAISO-Gates Greg Approved Sponsor Project Agreement, filed May 18, 2017 in Docket No. ER17-1628.

Imperial Valley
Need: policy

Project detail: 230 kV collector substation (located approximately one mile north of the Imperial Valley ("IV") substation) and a 230 kV transmission line connecting the collector substation to the IV substation.

Bidders:[162]

- Imperial Irrigation District
- Abengoa Transmission & Distribution

Winner: Imperial Irrigation District[163]

Winning bid: $14,283,122

Notes: CAISO filed the APSA with FERC on May 23, 2014 in Docket No. ER14-2033-000 and FERC accepted the APSA effective July 23, 2014. The APSA had cost cap of $14,283,122.[164] The project began development in July 2013 and was originally scheduled for energization on May 15, 2015. CAISO received notice from the Imperial Irrigation District on November 24, 2015 exercising its right to terminate the APSA.

ISO Project Cost estimate: $25 million, produced 2013[165]

Proposed In-service Date: January 2015

MISO

Duff-Coleman
Need: efficiency

Project: MISO initiated its first solicitation process in January 2016 when it issued an RFP for a market efficiency project known as the Duff-Coleman EHV 345 kV Competitive Transmission Project, a 345-kV transmission line connecting the Duff substation in southern Indiana to the Coleman EHV substation in western Kentucky.

Bidders:

- Ameren Transmission Company of Illinois and PPL TransLink, Inc.
- Duke-American Transmission Company, LLC
- Edison Transmission, LLC
- GridAmerica Holdings, Inc.

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162 CAISO, Imperial Valley Project Sponsor Selection Report, July 11, 2011, p. 3.
163 CAISO, Imperial Valley Project Sponsor Selection Report, July 11, 2011, p. 1.
164 CAISO Transmittal Letter, Docket No. ER16-508, December 11, 2015, p. 41.
165 CAISO, Imperial Valley Project Sponsor Selection Report, July 11, 2011, p. 2.

- ITC Midcontinent Development, LLC
- Midcontinent MCN, LLC
- NextEra Energy Transmission Midwest, LLC
- Republic Transmission, LLC
- Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Incorporated and Public Service Enterprise Group. Inc.
- Transource Energy, LLC
- Xcel Energy Transmission Development Company, LLC.

Winner: Republic Transmission, LLC., a partnership between Big Rivers Electric Corporation and LS Power, with a bid of $49.8 million.[166] Republic Transmission's bid included a "firm rate base cap" of $58.1 million, or $47 million in 2016 dollars. MISO stated that the firm rate base cap transfers escalation risk and administrative and general cost increase risk away from customers.

ISO Implementation Cost: $1,331,940[167]

Notes: In March 2017 Republic Transmission petitioned FERC for certain transmission rate incentives related to the Duff-Coleman project, including: 1) deferred recovery of prudently incurred pre-commercial costs through creation of a regulatory asset; 2) full recovery of prudently-incurred costs if the project is abandoned for reasons beyond Republic's control; 3) use of a hypothetical capital structure consisting of 55% debt and 45% equity until the project achieves commercial operation; and 4) 50 basis point adder to Republic's return on equity ("ROE") for participating in a RTO, subject to the overall ROE cap accepted by MISO.[168] The Commission approved Republic's request for incentives with certain restrictions in October 2017, including the establishment of a regulatory asset for pre-commercial costs.[169]

ISO Project Cost Estimate: MISO estimated project cost was $58.9 million.[170]

166 MISO Duff-Coleman Selection Report, December 20, 2016, p. 38.
167 MISO, *Competitive Developer Selection Process Incurred Costs*, https://cdn.misoenergy.org/Incurred%20Costs%20-%20Duff-Coleman%20EHV%20345kV82322.pdf
168 Republic Petition, March 22, 2017, Docket No. EL17-52-000, p. 2.
169 *Republic Transmission, LLC, Order Granting Petition for Declaratory Order*, 161 FERC ¶ 61,036, (October 6, 2017).
170 MISO, Duff-Coleman Selection Report, December 20, 2016, p. 5.

Hartburg Sabine

Project: 500 kV line known as Hartburg-Sabine Junction. The MISO scoping level estimated project cost was reported as $122.4 million.[171]

Bidders:

- Avangrid Networks, Inc.
- EasTex TransCo, LLC
- GridLiance Heartland, LLC
- ITC Midcontinent Development, LLC / Hunt Transmission Services, LLC
- Midwest Power Transmission Arkansas, LLC
- NextEra Energy Transmission Midwest, LLC
- Transource Energy, LLC
- Verdant Plains Electric, LLC
- Xcel Energy Transmission Development Company, LLC

Winner: NextEra Energy Transmission Midwest won the solicitation with a project implementation cost capped at $114.8 million. NextEra submitted an estimated annual transmission revenue requirement of $95.0 million.[172] The transmission revenue requirement will be capped only for the first ten years of the project's service life. Other NextEra cost caps include an ROE cap of 9.8%, an equity ratio cap of 45%, and caps on O&M for the first ten years of the project's rate recovery.

ISO Evaluation Cost: $1,137,240[173]

PJM

PJM has conducted many solicitations for new projects since implementing Order No. 1000.[174] PJM indicated in a May 2019 presentation that the RTO incurred $447,717 to evaluate 2016 Proposal Windows 1, 2, and 3 and $1,230,402 to evaluate the 2016/17 long term proposal window and Window 1 in 2017 proposals.[175] The Brattle Report only estimates cost savings for the Artificial Island solicitation.

171 MISO, Hartburg-Sabine Selection Report, November 27, 2018, p. 5.
172 MISO, Hartburg-Sabine Selection Report, November 27, 2018, pp. 5-6.
173 MISO, Competitive Developer Selection Process Incurred Costs, January 25, 2019.
174 *See e.g.*, Federal Energy Regulatory Commission, 2017 Transmission Metrics Staff Report (October 6. 2017) pp. 16-18.
175 PJM, *Cost Containment Status and Next Steps* (May 16, 2019) at p. 20, https://www.pjm.com/-/media/committees-groups/committees/pc/20190516/20190516-item-08-cost-containment-status-and-next-steps.ashx

Artificial Island

PJM, which uses a sponsorship model to comply with Order 1000, does not produce planning-level estimates of the transmission needs it issues solicitations for. As such, the Brattle Report uses a PSE&G bid as a "reference cost" to estimate the cost savings from the Artificial Island solicitation. Concentric identified the sources of the two figures Brattle used to estimate the savings, which Brattle claims were 60%, associated with the solicitation process. The table below summarizes these sources.

Brattle Report Artificial Island Cost Estimate Sources

"Differences in Competitive Bids and Initial Cost Estimates"	RTO/Incumbent Estimate of Project Cost ($ M)	Winning Competitive Bid ($ M)	"Cost Advantage" of Winning Bid
Brattle Figure 13	$692	$280	60%
Source	PJM Artificial Island White Paper, July 2015 at 12, referencing PSE&G's Project P2013_1-7E "New Freedom – Deans 500 and Salem-Hope Creek 500 kV lines.	PJM AI update to TEAC, March 3, 2017 at 13 ($143 M for 230 kV Line and Silver Run Substation + $132M for Hope Creek 2B Interconnection + $2M for DE Interconnection)	

The source of Brattle Report's figure for the Incumbent cost estimate is PSE&G project # P2013_1-7E.[176]

Bidders that provided supplemental responses: [177]

- Dominion High Voltage (2013-1-1A)
- Dominion High Voltage (2013-1-1C)
- Transource (2013-1-2B) (also has a "Redacted Public Power Proposal")
- Northeast Transmission Development (2013-1-5A)
- PSE&G (2013-1-7K)
- Virginia Electric and Power Company
- First Energy Corporation
- Pepco Holdings, Inc and Exelon Corporation
- Atlantic Grid Holdings LLC
- PSE&G

Winner: LS Power.

Notes: See the Artificial Island Case Study in Section 4.1 of this report.

Ap South

Need: Market Efficiency 2014/15 Long Term Proposal Window[178]

176 PJM, Artificial Island Project Recommendation, July 29, 2015, at 12.
177 *See* PJM website https://www.pjm.com/planning/competitive-planning-process/closed-artificial-island-proposals.aspx
178 PJM, Transmission Expansion Advisory Committee Market Efficiency Update, presented to the TEAC on June 9, 2016, p. 3.

Bidders:[179]

Project	Cost Estimate ($ million)	Schedule Estimate (months)
6C	$41.1	32
6D	$38.5	30
9A	$267.1	59
14A	$52.6	42
19G	$46.6	33

Winner: Project 9A- Transcource Energy (an AEP affiliate), with integration work completed by BG&E and Allegheny Power. PJM released the results of its assessment where it determined that Project 9A offered the highest cost-benefit ratio.[180] The PJM Board approved staff's recommendation on August 2, 2016. PJM executed a Designated Entity Agreement with Transource Energy on November 2, 2016.[181]

Notes: The proposed capital cost for Project 9A was $269,073,000, with upgrades on incumbent TO systems bringing the cost to $340.6 million.[182] PJM reevaluated Project 9A in four times (September 2017, February 2018, September 2018, and November 2018) and continued to find a favorable cost-benefit ratio. The updated capital cost during a third re-evaluation that found the project continued to have a favorable cost-benefit ratio, was $372.23 million.[183]

Proposed In-Service Date: 2020

NYISO

NYISO has a sponsorship model and has carried out two solicitations –Western NY and AC Transmission. NYISO does not publicly release the winning bids but instead publishes project cost estimates produced by the independent consultant Substation Engineering Co.

Western NY Public Policy
Need: Policy

Project: build a power line that would allow for increased deliveries from a major New York Power Authority hydroelectric project and bring in renewable imports from Canada.

179 PJM, PJM 2014/2015 Long Term Proposal Window Independent Cost Review White Paper, April 28, 2016, p. 1.
180 PJM, Transmission Expansion Advisory Committee Market Efficiency Update, presented to the TEAC on June 9, 2016, p. 5.
181 *PJM Interconnection, L.L.C.*, Order Accepting Subject to Condition and Suspending Proposed Agreement, 158 FERC ¶ 61,021, (January 12, 2017) at P1.
182 PJM, Transmission Expansion Advisory Committee Market Efficiency Update, presented to the TEAC on June 9, 2016, p. 3.
183 PJM Transource Independence Energy Connection Market Efficiency Project, November 15, 2018, pp. 10-11.

Bidders:

Table 2-3: Proposed Projects

Developer	Project Name	Project ID	Category	Type	Location (County/State)
NRG Dunkirk Power	Dunkirk Gas Addition	OPP02	OPPP	ST	Chautauqua, NY
North America Transmission	Proposal 1	T006	PPTP	AC	Niagara-Erie, NY
North America Transmission	Proposal 2	T007	PPTP	AC	Niagara-Erie, NY, Wyoming, NY
North America Transmission	Proposal 3	T008	PPTP	AC	Niagara-Erie, NY, Wyoming, NY
North America Transmission	Proposal 4	T009	PPTP	AC	Niagara-Erie, NY, Wyoming, NY
ITC New York Development	15NYPP1-1 Western NY AC	T010	PPTP	AC	Niagara-Erie, NY
National Grid	Moderate Power Transfer Solution	T011	PPTP	AC	Niagara-Erie, NY
National Grid	High Power Transfer Solution	T012	PPTP	AC	Niagara-Erie, NY
NYPA/NYSEG	Western NY Energy Link	T013	PPTP	AC	Niagara-Erie, NY, Wyoming, NY
NextEra Energy Transmission New York	Empire State Line Proposal 1	T014	PPTP	AC	Niagara-Erie, NY
NextEra Energy Transmission New York	Empire State Line Proposal 2	T015	PPTP	AC	Niagara-Erie, NY
Exelon Transmission Company	Niagara Area Transmission Expansion	T017	PPTP	AC	Niagara-Erie, NY

PPTP = Public Policy Transmission Project　ST = Steam Turbine
OPPP = Other Public Policy Project　AC = Alternating Current Transmission

Source: NYISO, Western NY Public Policy Transmission Planning Report (October 17, 2017) p. 15.

Independent Third-Party Cost Estimates for Western NY proposals:[184]

Project ID	Independent Cost Estimate: 2017 $M
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

Winner: NextEra Energy Transmission New York, Inc., ("NEETNY") Empire State Line Project 1 (T014).[185] The project includes a new Dysinger 345 kV substation, a new East Stolle 345 kV 17 switchyard, and a 345 kV line connecting Dysinger and East Stolle substations, with a 700 MVA 345 kV phase angle regulator at the Dysinger switchyard. All facilities will predominantly use existing rights-of-way.[186]

Notes: NEETNY filed an application with the New York State Public Service Commission in August 2018 for a certificate of environmental compatibility and public need to build, operate, and maintain the Empire State Line Project. NEETNY also made a filing with FERC to establish the architecture for a formula rate and requested ROE adders, which FERC approved in November 2017.[187]

Proposed in-service date: June 2022.[188]

AC Transmission
Need: Policy

Project: Two new 345-kV transmission lines to address persistent transmission congestion at the Central East (Segment A) electrical interface and Upstate New York/Southeast New York (UPNY/SENY, or Segment B).[189]

Window: February 29, 2016 - April 29, 2016

Bidders: Six Developers submitted 16 project proposals

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184 NYISO, Western New York Public Policy Transmission Planning Final Report, October 17, 2017, p. 38.
185 NYISO Press Release, *NYISO Selects NextEra Transmission Project to Increase Access to Hydro Power*, October 17, 2017.
186 NextEra Energy Transmission New York, Inc. Application for a Certificate of Environmental Compatibility and Public Need, New York State Department of Public Service Case No. 18-T-0499, Testimony of Michael Lanon, August 10, 2018, p. 4.
187 *NextEra Energy Transmission New York, Inc.*, 161 FERC ¶ 61,138 (November 3, 2017).
188 Transmission Hub, https://www.transmissionhub.com/articles/2018/08/neetny-seeks-regulatory-approval-in-new-york-of-345-kv-empire-state-line-project.html
189 NYISO, AC Transmission, AC Transmission Public Policy Transmission Need Viability and Sufficiency Assessment, September 16, 2016.

AC Transmission Proposals

Developer	Project Name	Category	Type	Location	Size
National Grid / Transco	New York Energy Solution Seg. A	PPTP	AC Transmission	Segment A	N/A
National Grid / Transco	New York Energy Solution Seg. B	PPTP	AC Transmission	Segment B	N/A
NextEra Energy Transmission New York	Enterprise Line: Segment A	PPTP	AC Transmission	Segment A	N/A
NextEra Energy Transmission New York	Enterprise Line: Segment B	PPTP	AC Transmission	Segment B	N/A
NextEra Energy Transmission New York	Enterprise Line: Segment B-Alt	PPTP	AC Transmission	Segment B	N/A
North America Transmission / NYPA	Segment A +765 kV	PPTP	AC Transmission	Segment A	N/A
North America Transmission / NYPA	Segment A Base	PPTP	AC Transmission	Segment A	N/A
North America Transmission / NYPA	Segment A Double Circuit	PPTP	AC Transmission	Segment A	N/A
North America Transmission / NYPA	Segment A Enhanced	PPTP	AC Transmission	Segment A	N/A
North America Transmission / NYPA	Segment B Base	PPTP	AC Transmission	Segment B	N/A
North America Transmission / NYPA	Segment B Enhanced	PPTP	AC Transmission	Segment B	N/A
ITC New York Development	16NYPP1-1A AC Transmission	PPTP	AC Transmission	Segment A	N/A
ITC New York Development	16NYPP1-1B AC Transmission	PPTP	AC Transmission	Segment B	N/A
AvanGrid	Connect New York Recommended	PPTP	HVDC	Segments A and B	1000 MW
AvanGrid	Connect New York Alternative	PPTP	HVDC	Segments A and B	1000 MW
GlidePath	Distributed Generation Portfolio	OPPP	Generation	Orange, Ulster, Putnam, Greene, NY	112 MW

PPTP: Public Policy Transmission Project OPPP: Other Public Policy Project

Source: NYISO, ESPWG/TPAS Presentation, September 26, 2016 [190]

Third party estimate of AC Transmission Proposal Costs

Table A-3: Cost per MW Ratio

Project	Segment B Independent Cost Estimate (2018 $M)	Incremental UPNY/SENY (MW)	Cost per MW
T027+T019	$479	2,100	**0.228**
T027+T022	$373	1,600	**0.233**
T027+T023	$424	1,550	**0.274**
T027+T029	$422	1,475	**0.286**
T027+T030	$441	1,600	**0.276**
T027+T032	$536	1,525	**0.351**

The results show that T019 has the lowest Cost per MW ratio of all the Segment B projects.

Source: NYISO, AC Transmission, Revised Draft Report Addendum.[191]

Winners:

<u>Segment A</u>: NYISO staff recommended and the NYISO Board approved Project T027, a joint proposal by North America Transmission and the New York Power Authority to construct a double-circuit 345-kV line from Edic to New Scotland.

190 NYISO, AC Transmission, AC Transmission Public Policy Transmission Need Viability and Sufficiency Assessment, September 26, 2016, p. 10.

191 NYISO, AC Transmission Public Policy Transmission Planning Report Addendum, Draft, February 20, 2019, p. 11.

Segment B: NYISO staff recommended a joint proposal by North America Transmission and the New York Power Authority (project T029). However, the NYISO Board revised the NYISO staff's selection for Segment B, and selected a competing proposal by National Grid and New York Transco (project T019). The NYISO Board determined that project T019 "demonstrated superior performance across a broader range of metrics when compared to Project T029 and the other proposed Segment B projects, including, significantly, providing additional transfer capability across the UPNY/SENY transmission interface."[192]

SPP

To date, SPP's integrated transmission planning process has only recommended one project for solicitation, a 21-mile 115 kV line from North Liberal to Walkemeyer Station. SPP hires a third-party industry expert panel to review proposals for new transmission projects.

Walkemeyer

Bidders: The Walkemeyer solicitation had 11 total proposals with costs ranging from $17.1 million to $7.5 million.[193]

Winner: Mid Kansas Electric Company, with a total project cost of $8.3 million.[194] All other project bidders remain confidential. The Walkemeyer project was canceled in June 2016 due to declining load.

ISO Project Cost Estimate: $17.5 million[195]

ISO Evaluation Cost: $522,196[196]

192 NYISO, Notice of Board of Directors' Decision on Approval of AC Transmission Public Policy Transmission Planning Report and Selection of Public Policy Transmission Projects (April 8, 2019) at 4.
193 Industry Expert Panel Recommendation Report, RFP-000001 (Walkemeyer - North Liberal 115kV) April 12, 2016, p. 4, Table 1.
194 SPP 2016 Q3 Quarterly Project Tracking Report, p. 7.
195 SPP, MOPC Report to Board of Directors / Members Committee, April 28, 2015, slide 51.
196 SPP Strategic Planning Committee – Order 1000 Workshop Meeting Minutes (July 7, 2016), p. 1.

APPENDIX D: COST CAPS

Cost caps have been included in multiple ISO/RTO solicitation proposals and comprise a broad range of containment measures. The following provides an overview of bidders' proposed cost caps in each RTO or ISO that held solicitations.

CAISO

HENRY ALLEN TO ELDORADO (DESERTLINK)[197]

Incentive rate treatments:

- Deferred recovery of prudently incurred pre-commercial costs through creation of a regulatory asset
- Full recovery of prudently incurred costs if the project is abandoned for reasons beyond DesertLink's control
- Use of a hypothetical capital structure consisting of 50% debt and 50% equity until the project achieves commercial operation
- 50-basis point RTO Participation adder subject to the overall ROE not exceeding the ROE cap commitment in DesertLink's Project proposal (9.8%)

MISO

DUFF-COLEMAN (REPUBLIC TRANSMISSION)

- "Firm rate base cap" of $58.1 million, or $47 million in 2016 dollars.[198]
- MISO discussed that the firm rate base cap transfers escalation risk and administrative and general cost increase risk away from customers.

FERC RATE INCENTIVES:[199]

- Deferred recovery of prudently incurred pre-commercial costs through creation of a regulatory asset;
- Full recovery of prudently incurred costs if the Project is abandoned for reasons beyond Republic's control;

197 *DesertLink, LLC,* Order on Transmission Owner Tariff and Formula Rate Proposal, Establishing Hearing and Settlement Judge Procedures and Dismissing Request for Rehearing, 161 FERC ¶ 61,126 (October 31, 2017). Note, not all CAISO project cost caps are discussed herein.

198 Duff-Coleman Selection Report, December 20, 2016, p. 38

199 *Republic Transmission, LLC,* Order Granting Petition for Declaratory Order, 161 FERC ¶ 61,036 (October 6, 2017).

- Use of a hypothetical capital structure consisting of 55% debt and 45% equity until the project achieves commercial operation, which ratio is consistent with Republic's commitment and accepted by MISO; and
- 50-basis point adder to Republic's ROE for participating in a RTO, subject to the overall return on equity cap (inclusive of incentives) Republic committed to as part of its project proposal submitted to and accepted by MISO.[200,201]

Other proposals offer cost caps such as caps on ROE, capital structure, implementation costs, O&M costs, inflation rate assumptions, and other rate concessions.

HARTBURG-SABINE (NEXTERA ENERGY TRANSMISSION MIDWEST)

Project implementation cost capped at $114.8 million[202]

Estimated annual transmission revenue requirement of $95.0 million or $11 million below the median estimate, capped for the first 10 years of project's recovery lifetime.[203]

ROE cap of 9.8%, an equity ratio cap of 45%, and caps on O&M for the first ten years of the project's rate recovery.

Other proposals' cost caps included caps on total implementation cost, foregoing AFUDC, foregoing CWIP, a line route changes from the Texas siting authority, ROE and equity ratio caps, and caps on annual transmission revenue requirement and O&M expenses that range from 5 years to 40 years.[204]

SPP

WALKEMEYER (MID KANSAS ELECTRIC COMPANY)

- The Walkemeyer project was canceled in June 2016 due to declining load.
- Cost containment ability and experience metric was considered in evaluation of each RFP

Other proposals included various cost cap provisions such as total cost caps, ROE and equity ratio caps, and rate base caps. The proposals also included a mix of provisions for cost overrun pass-throughs such as capitalized property taxes.

200 Republic Transmission, LLC Transmittal Letter, Docket No. EL17-52-000, March 22, 2017, p. 2.

201 *Republic Transmission, LLC,* Order Granting Petition for Declaratory Order, 161 FERC ¶ 61,036. Docket No. EL17-52-000. (October 6, 2017). Republic argued that the requested incentives "are narrowly tailored to the risks faced in the development and construction of the Project and will allow Republic to attract the capital necessary to move forward with the Project in the most efficient and cost-effective manner." The FERC approved Republic's request for incentives with certain restrictions in October 2017, including the establishment of a regulatory asset for pre-commercial costs.

202 MISO, Hartburg-Sabine Selection Report, November 27, 2018, p. 5.

203 MISO, Hartburg-Sabine Selection Report, November 27, 2018, p. 5-6.

204 Hartburg-Sabine Selection Report, November 27, 2018, p. 20.

NYISO

WESTERN NEW YORK PUBLIC POLICY

- FERC ROE incentives[205]
- NYISO did not take cost caps into account in its selection process noting it is not required by Order No. 1000.

AC PUBLIC POLICY TRANSMISSION NEEDS

- NYSPC highly encouraged cost containment incentives, noting that the developer should share in some portion of cost overruns should they occur. Similarly, the developer should share in any cost savings should they occur.[206]

PJM

ARTIFICIAL ISLAND (NORTHEAST TRANSMISSION DEVELOPMENT)

- Northeast Transmission Development received FERC-approved ROE, debt/equity structure, abandonment recovery, and cost containment provisions.
- Construction cost cap subject to certain exemptions.

AP SOUTH (TRANSOURCE)

- Project cost cap of $197.1 million, with an annual 3% compounded escalation adjustment to account for inflation as measured from the bid submission date of February 27, 2015 and the Project In-Service Date in 2020.
- FERC-approved ROE plus incentives on the costs incurred for the Project up to the Estimated Project Cost;
- FERC-approved ROE on the costs incurred for the Project above the Estimated Project Cost, but shall forego any return on equity incentives approved by FERC (including the RTO participation adder) for the project cost portion that exceeds the Estimated Project Cost; and
- Cap on actual equity content of no greater than 50% for the Project, once permanent financing is in place.
  - Transource shall be granted relief from this commitment if the capital market conditions do not remain normal and the Transource Subsidiaries do not have the ability to finance these transmission projects with the proposed capital structure.

205 *NextEra Energy Transmission New York, Inc.*, 161 FERC ¶ 61,138 (November 3, 2017) at P 2.

206 State of New York Public Service Commission, Case 12-T-0502, *et al.* (December 17, 2015) at pp. 47-48.

APPENDIX E: ORDER NO. 1000 BACKGROUND

In July 2011, the Federal Energy Regulatory Commission issued a final rule entitled *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*.[207] The Commission subsequently clarified and revised the Order No. 1000 requirements in Order No. 1000-A[208] in May 2012 and Order No. 1000-B[209] in October 2012. It is important to understand the scope of FERC's Order No. 1000 reforms,[210] specifically what they did and did not require with respect to transmission planning. Regarding transmission planning, Order No. 1000 required public utility transmission providers, such as Independent System Operators ("ISOs") or Regional Transmission Organizations ("RTOs"), to:

- Participate in a regional transmission planning process that produces a regional transmission plan;
- Amend its Open Access Transmission Tariff ("OATT") to describe procedures to consider transmission needs driven by public policy requirements established by local, state, or federal laws or regulations in the local and regional transmission planning processes;
- Remove federal ROFRs from Commission-jurisdictional tariffs and agreements for certain new transmission facilities; and
- Improve coordination between neighboring transmission planning regions for new interregional transmission facilities.[211]

Order No. 1000 also established regulations related to allocating the costs of new transmission facilities selected through a regional planning process to subregions of a planning region (e.g., zones). However, these cost allocation requirements are not the focus of this report and are not discussed herein. Order No. 1000 also required that the regional transmission planning process result in a regional transmission plan that satisfies the transmission planning requirements set forth in Order No. 890: 1) coordination; 2) openness; 3) transparency; 4) information exchange; 5) comparability; 6) dispute resolution; and 7) economic planning.[212]

The Order No. 1000 requirements were never intended to open all new FERC-jurisdictional transmission facilities – or some arbitrary percentage of them – to solicitation. Rather, the Order No. 1000 requirements

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207 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 136 FERC ¶ 61,051 (July 21, 2011) (Order No. 1000).

208 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 139 FERC ¶ 61,132 (May 17, 2012) (Order No. 1000-A).

209 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 141 FERC ¶ 61,044 (October 18, 2012) (Order No. 1000-B).

210 This report refers to the requirements promulgated in Order No. 1000, as clarified in Order Nos. 1000-A and 1000-B, collectively as "Order No. 1000 requirements" or "Order No. 1000". Distinctions are only made for purposes of citation.

211 Order No. 1000 Summary.

212 Order No. 1000 at PP 146, 151. These transmission planning principles are explained in Order No. 890 (*Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, order on reh'g, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), order on reh'g, Order No. 890-B, 123 FERC ¶ 61,299 (2008), order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228, order on clarification, Order No. 890-D, 129 FERC ¶ 61,126 (2009)).

were discretely focused on a subset of new transmission facilities. Specifically, Order No. 1000's transmission planning requirements require public utility transmission providers to adopt transparent and not unduly discriminatory criteria for selecting *new* transmission facilities in a *regional* transmission plan for *purposes of cost allocation.*[213] As such, the Order No. 1000 requirements only applies to transmission facilities that meet all three of the following requirements:

- new facilities (i.e., not upgrades to existing facilities)
- selected as part of a regional transmission plan (as opposed to a local plan)
- allocated regionally (i.e., not allocated solely within a single zone).

The three requirements are discussed in turn below. In promulgating the Order No. 1000 requirements, the Commission determined it was necessary, in certain circumstances, to eliminate the federal right of first refusal ("ROFR") afforded to incumbent transmission owners from FERC-jurisdictional tariffs and agreements to ensure the selection of new transmission facilities through the regional planning process for purposes of cost allocation does not impede a nonincumbent transmission developer's participation in regional transmission planning.[214] Practically speaking, removing the federal ROFR from FERC-jurisdictional tariffs and agreements (e.g., ISO/RTO tariffs or TO participation agreements) permitted nonincumbent transmission developers to propose alternative solutions in the regional transmission planning process. The Order No. 1000 requirements only apply to certain transmission projects, and the ISO/RTO tariffs that the Commission ultimately approved to comply with Order No. 1000 requirements retain an incumbent TO's federal ROFR for other transmission projects. The transmission projects that are subject to the Order No. 1000 requirements – new facilities that are selected in a regional plan with costs that are allocated regionally – are discussed below.

New transmission facilities

Order No. 1000 applies to new facilities, not upgrades. As such, the Order No. 1000 requirements only eliminated the federal ROFR from FERC-jurisdictional tariffs and agreements for *new* transmission facilities selected in a regional plan for purposes of cost allocation.[215] Accordingly, incumbent TOs retained a federal ROFR for upgrades to their own transmission facilities .[216] For example, the Commission stated that the Order No. 1000 requirements:

> [D]o not affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities, such as in the case of tower change outs or reconductoring, regardless of whether or not an upgrade has been selected in the regional transmission plan for purposes of cost allocation. In other words, an incumbent transmission

213 See e.g., Order No. 1000-A at P 455 and Order No. 1000-B at P 59.

214 See e.g., Order No. 1000 at PP 261, 320. See also Order No. 1000 at P 261.

215 Order No. No. 1000-A at 415. See also Order No. 1000-B at P 41.

216 The NYISO tariff and agreements did not contain any federal ROFRs and thus were not required to modify any ROFR pursuant to Order No. 1000 requirements.

provider would be permitted to maintain a federal right of first refusal for upgrades to its own transmission facilities.[217]

In Order No. 1000-A, the Commission clarified that an upgrade is an "improvement to, addition to, or replacement of a part of, an existing transmission facility" and does not refer to an entirely new transmission facility.[218]

Facilities selected in a regional transmission plan

ISO/RTO transmission planning involves both a local aspect, which generally occurs within a given incumbent TO's distribution service territory, and a regional aspect related the integrated operation of the local distribution service territories within a larger planning region (e.g., ISO/RTO). As noted above, the Order No. 1000 requirements only applied to new transmission facilities that are *selected through a regional transmission plan for the purposes of cost allocation.* As such, Order No. 1000 did not require ISOs/RTOs to eliminate an incumbent TO's federal ROFR to construct local transmission facilities, where the Commission defined a "local transmission facility" as a "transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation."[219]

The Commission explicitly recognized the fact that incumbent TOs must comply with reliability standards and have an obligation to serve customers. Accordingly, the Commission affirmatively stated that the Order No. 1000 requirements were not intended to disrupt a TO's local planning processes:

> We clarify that our actions today are not intended to diminish the significance of an incumbent transmission provider's reliability needs or service obligations. Currently, an incumbent transmission provider may meet its reliability needs or service obligations by building new transmission facilities that are located solely within its retail distribution service territory or footprint. The Final Rule continues to permit an incumbent transmission provider to meet its reliability needs or service obligations by choosing to build new transmission facilities that are located solely within its retail distribution service territory or footprint and that are not submitted for regional cost allocation.[220]

Order No. 1000 did not create a categorical exemption from eliminating a jurisdictional federal ROFR for reliability projects selected through the regional planning process.[221] However, the Commission stressed the importance of the incumbent TO's responsibility to maintain reliability in its service territory. Specifically, Order No. 1000 states that "nothing herein restricts an incumbent transmission provider from developing a local transmission solution that is not eligible for regional cost allocation to meet its reliability needs or service obligations in its own retail distribution service territory or footprint."[222]

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217 Order No 1000 at P 319. *See also* Order No. 1000-A at P 426.
218 Order No. 1000-A at P 426.
219 Order No. 1000 at P 63.
220 Order No. 1000 at P 262.
221 Order No. 1000-A at P 428.
222 Order No. 1000 at P 329.

The Commission also recognized that reliability issues may need be addressed quickly and that, "one function of the regional transmission planning process is to identify those transmission facilities that are needed to meet identified needs on a timely basis and, in turn, enable public utility transmission providers to meet their service obligations."[223] For example, Order No. 1000 required public utility transmission providers to have procedures in place in the event that a transmission project selected through the regional planning process experienced development delays that could threaten an incumbent TO's obligation to meet its reliability needs or service obligations.[224]

The Commission also recognized the need to satisfy reliability requirements in a timely matter in the Order No. 1000 compliance orders it issued for the six jurisdictional ISOs/RTOs.[225] As discussed further below in the Order 1000 compliance section of this Appendix, the Commission has accepted ISO/RTO tariff provisions that retain, in certain circumstances, an incumbent TO's federal ROFR to construct a transmission project in that TO's service territory if a given project is needed by a certain date for reliability purposes.

For example, when the Commission approved PJM's Order No. 1000 compliance filing to designate the incumbent TO as the transmission developer of "Immediate Need Reliability Projects," which are projects needed in three years or less. The Commission stated "We agree with PJM that there may be instances in which it may not be feasible to hold a competitive solicitation process to solve a reliability violation. Thus, to avoid delays in the development of transmission facilities needed to resolve a time-sensitive reliability criteria violation, we find that it is just and reasonable to include a class of transmission projects that are exempt from the competitive solicitation."[226] The Commission approved similar provisions in ISO-NE and SPP.

Projects with regionally allocated costs

The Commission Order No. 1000 requirements only apply to new transmission projects that are selected through a regional planning process and for which the costs will be allocated to more than one zone. The Commission clarified in Order No. 1000-A that Order No. 1000 "does not require elimination of a federal right of first refusal for a new transmission facility if the regional cost allocation method results in 100% of the facility's cost being allocated to the public utility transmission provider in whose retail distribution service territory or footprint the facility is to be located."[227] In Order No. 1000-A the Commission further clarified that the phrase "selected in a regional transmission plan for purposes of cost allocation" "excludes a new transmission facility if the costs of that facility are borne entirely by the public utility transmission provider in whose retail distribution service territory or footprint that new transmission facility is to be located."[228] The Commission also clarified in Order No. 1000-B that the act of selecting a new transmission facility in the

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223 Order No. 1000 at P 264.

224 Order No. 1000 at P 329. *See also* Order No. 1000-A at P 428.

225 ISO/RTO Order No. 1000 compliance orders, which occurred over several iterations, are available here: https://www.ferc.gov/industries/electric/indus-act/trans-plan/regional.asp?csrt=917136660019168714

226 PJM Interconnection, L.L.C., 142 FERC ¶ 61,214 (March 22, 2013) at P 247.

227 Order No. 1000-A at P 423.

228 Order No. 1000-A at P 423.

regional transmission plan for purposes of cost allocation triggers the applicability and attendant requirements of Order No. 1000.[229] Accordingly, transmission facilities that are not selected through a regional planning process (e.g., selected through a local planning process) and facilities that are selected through a regional planning process but not for purposes of regional cost allocation are not subject to Order No. 1000 requirements.

ROFR and rights-of-way granted by others

FERC only has jurisdiction over ROFRs, to the extent they exist, in FERC-jurisdictional tariffs and agreements. However, an incumbent TO may have a ROFR to construct a transmission project within its service territory that is granted by a state or local authority. The Commission clarified in Order No. 1000-A that the requirement to eliminate a federal ROFR in certain circumstances does not preempt state law because the Order No. 1000 requirements are "focused on Commission-jurisdictional tariffs and agreements, and are not intended to preempt state or local laws or regulations."[230] With respect to rights of way in particular, the Commission explained that Order No. 1000 requirements are "not intended to alter an incumbent transmission provider's use and control of its existing rights-of-way"[231] and that the requirements do not "grant or deny transmission developers the ability to use rights-of-way held by other entities, even if transmission facilities associated with such upgrades or uses of existing rights-of-way are selected in the regional transmission plan for purposes of cost allocation."[232]

229 "[O]nce a new transmission facility is selected in the regional transmission plan for purposes of cost allocation, it is no longer a local transmission facility exempt from the requirements of Order Nos. 1000 and 1000-A regarding the removal of federal rights of first refusal." Order No. 1000-B at P 52.

230 Order No. 1000-A at P 379.

231 Order No. 1000 at P 319.

232 Order No. 1000 at P 319.

DAIRYLAND POWER
COOPERATIVE

February 2, 2022

Representative Mike Kuglitsch
Chairman, Committee on Energy and Utilities
129 West, State Capitol
Madison, WI 53708

Subject: Support for Senate Bill 838/Assembly Bill 892

Dear Chairman Kuglitsch and Members of the Committee,

Dairyland Power is a Generation and Transmission cooperative headquartered in La Crosse, Wisconsin, serving member cooperatives in Wisconsin, Minnesota, Iowa and Illinois. Dairyland provides the wholesale power supply and other services to 24- distribution cooperatives and 17 municipal utilities in the Upper Midwest. Electricity is delivered via 3,200 miles of transmission lines and over 350 substations located throughout our 44,500 square mile service area. In turn, the member distribution co-ops and municipals customers deliver the electricity to consumers—meeting the needs of more than a half-million people.

Dairyland is a Member of The Midcontinent Independent System Operator or MISO. This is an independent, not for profit, member-based organization that is responsible for operating the power grid across 15 states and Manitoba, Canada. MISO also coordinates with its members and stakeholders in planning the grid for the future.

The four key pillars in the utility sector are Reliability, Affordability, Sustainability and Safety. As a non-profit electric cooperative with an 80-year history of providing critical services in the Upper Midwest, Dairyland supports SB 838/AB 892 because planning for reliable, cost effective power delivery is in the best interest of our members, Wisconsin, the regional electric grid, and energy consumers.

As a local transmission owner/operator in Wisconsin, Dairyland has a long history of reliable and cost-effective service in Wisconsin. Dairyland is committed to growing and supporting our communities and member distribution cooperatives in the wholesale purchase and delivery of electricity.

As a cooperative, we have a unique business model. Our non-profit status and the democratic Cooperative Business Model allow for local control by our member-consumers through local Boards of Directors. Local ownership by Dairyland also allows economic benefits of transmission ownership/operation to flow back to the local energy consumers. Transmission revenues off-set costs of service which help generate stable rates for our members over time.

SB 838/AB 892 will allow for local control, retaining a Wisconsin presence in building out and, more importantly, reliably operating the Wisconsin grid. Currently, our neighboring states—Minnesota, Iowa, Michigan, and the Dakotas— have moved to this model emphasizing a state's right rather than a federal selection to build out the transmission infrastructure.

Dairyland has a strong history of working collaboratively to support the development, construction, and operation of the electric grid. Dairyland is a member of the Grid North Partners (GNP), the group formerly known as CapX 2020. Grid North Partners is the result of Cooperatives, Municipal, and Investor-Owned Utilities serving consumers in Minnesota coming together to build out the next generation of high voltage transmission lines for improving reliability and enabling renewable energy. Included in this effort was the new power line from the Twin Cities to Rochester to La Crosse completed in 2016.

Dairyland has also collaborated with other utilities on the Badger Coulee transmission line and the on-going development of the Cardinal Hickory Creek transmission project.

By participating in these high voltage transmission efforts, Dairyland brings a non-profit, low capital investment cost benefit to the projects. Dairyland and our member distribution cooperatives also have existing utility rights-of-ways and relationships with the rural landowners impacted by the future transmission projects subject to this new legislation. Local control of transmission projects by utilities with a presence in Wisconsin benefits Wisconsin residents, landowners, and member-consumers that pay for electric service.

The Wisconsin Control of Transmission legislation ensures transmission development and long-term reliable operations remain within the state. Without this legislation, MISO has the authority and the obligation to choose transmission developers from its offices in Carmel, Indiana. MISO has expertise in regional transmission planning, that is choosing the right projects from a reliability and renewable energy enabling basis. In regard to siting a transmission line and working with local and state governments, Dairyland and the other utilities testifying today have the local knowledge and understand the impacts to the communities we serve.

The other significant consideration is the time it takes to plan, permit, and finally construct needed transmission lines. It is not a simple or quick process. Planning the right transmission lines and then preparing for the regulatory and environmental permitting process takes years. Without local control of transmission projects impacting Wisconsin, the MISO process of competitively bidding projects adds considerable time, up to another year as noted by ATC.

There is no need for this added process by MISO. The Wisconsin Certificate of Public Convenience and Necessity (CPCN) procedure along with Wisconsin Public Service Commission and Cooperative Boards of Director oversight already does a good job of ensuring competitive costs for transmission projects. These same institutions hold the local transmission owning utilities accountable for both cost and schedule.

In the end, transmission owning and operating electric utilities like Dairyland Power have over 80 years of experience effectively building and reliably operating the transmission system in Wisconsin. As our neighboring states already know, the local transmission owning utilities will do the best job of cost effectively developing and reliably operating the Wisconsin transmission system for the long-term. This will keep the jobs in Wisconsin, the transmission revenues in Wisconsin, and the control of the Wisconsin transmission grid in Wisconsin.

Thank you for the opportunity to testify in support of Senate Bill 838/Assembly Bill 892. Dairyland is pleased to provide our comments and answer questions that you may have for the panel.

Sincerely,

Ben Porath

Ben Porath
Chief Operating Officer
Dairyland Power Cooperative

BLP:JKS:meh

Testimony
Tony Clark, Sr. Advisor Wilkinson Barker Knauer, LLP
February 3, 2022
Wisconsin State Assembly
Committee on Energy and Utilities
Assembly Bill 892

Mr. Chairman and members of the Committee, my name is Tony Clark. I am a Senior Advisor at the firm of Wilkinson Barker Knauer, LLP, which has offices in Washington, DC and Denver. Prior to my current position I spent over two decades in the public sector. Most recently, I was a Commissioner of the Federal Energy Regulatory Commission, but my personal and professional background is Midwestern. I served for 12 years as a North Dakota Public Service Commissioner, approximately half that time as Commission Chairman. Prior to that, I was Labor Commissioner of North Dakota, and I was a state legislator, serving in the North Dakota House of Representatives. I am also proud to let you know, I'm a Wisconsin native, so I am particularly honored to appear before you today.

I hope to be able to provide you the perspective of someone who has worked on transmission and electric reliability issues in these number of different roles. My testimony today is on behalf of my firm's client, American Transmission Company.

The legislation that you are reviewing is similar to laws passed in at least ten other states, including the surrounding states in the Upper Midwest. The reason so many states like Wisconsin have adopted this legislation is two-fold.

First, state leaders have recognized that they have an interest in preserving some measure of state authority over the planning and execution of the wires portion of the electric business. Under the Federal Power Act, state and local governments' authority is much clearer when a utility actually serves customers in that state. This ensures a greater measure of local control and accountability. The utilities that serve retail customers tend to not plan and propose transmission projects if their own states are inalterably opposed to them. Because they serve customers in that state, and because the state has retail jurisdiction over them, they have an interest in not finding themselves getting crosswise with state officials and regulators. This aligns utility planning with the public interest. Pure merchant developers have no such nexus with the state. Their interest is getting selected by regional and interregional planners that are overseen by the Federal government – which may or may not reflect the preferences of Wisconsin. And coming out of the recent infrastructure package passed in Congress, there is even more reason to be concerned, because Congress – unfortunately in my view – greatly expanded the federal government's ability to site electric transmission projects against the wishes of a state.

Customers cannot reasonably choose their "own" transmission line. As such, it is a heavily regulated business. Transmission lines are not built in a vacuum. They are part of a planned, interconnected network that must work together to deliver 24/7 energy to customers. In planning that system, retail customer needs must come first, because they are the whole reason the system is built. Simply put, transmission exists to support customers' needs. Customers do not exist to support the plans of transmission developers. Therefore, the planning of the system – should be done from the bottom-up.

In conducting this planning, Wisconsin utilities must be responsive to the state's public policy goals determined by this legislature, and also to the oversight of your Public Service Commission. Sometimes, those plans might require new transmission lines. Other times, they may determine that customers are best served by generation closer to load, or through other energy conservation measures. Each of these decisions has cost and potential reliability trade-offs, which is why states have typically wanted to ensure their interests are protected. As with so many public policy issues, no one is going to care for the consumers, landowners and businesses of Wisconsin more than the people living here, so it only makes sense to want to keep maintain as best you can your ability to make these decisions.

If approved, this legislation will confirm that new transmission projects in Wisconsin will be constructed as part of the traditional regulatory structure. It simply codifies the practice that has served Wisconsin well. This helps ensure that Wisconsin's interests are placed first. The decisions that companies like ATC, Xcel and the retail customer serving utilities make are done with accountability – because they are made with the oversight of regulators who work to see that Wisconsin's public interest is met.

Second, other states have rejected the false dichotomy that is presented by opponents of this legislation. Opponents will tell you this is a matter of "free-market competition vs regulation." But that bumper sticker is not reality in this business. Unlike choosing a brand of laundry detergent, customers cannot choose their own transmission lines. The economics of this high fixed-cost, infrastructure heavy network industry preclude it. Rather, the choice you have as policy makers, is what type of regulation you will select to best protect your constituents. In my opinion, it boils down to a choice between one regulatory model with certain aspects of competition that has generally worked well for states and localities over many decades, and one newer regulatory model with other aspects of competition that has not worked in practice.

Under the form of regulation used in Wisconsin, the transmission owners and utilities whose primary purpose is ultimately to serve retail customers, are responsible for planning, designing, and operating the grid in a service territory. As part of that endeavor, they will often engage certain aspects of competition, such as solicitations of construction contracts, requests for proposal, and other processes to help demonstrate to their regulator that the project was not the result of self-dealing or gold plating. These costs must be prudently incurred, used and useful, and are reviewable by regulators before they are placed into rates. This is the essence of what is known as "cost-of-service" ratemaking. Yes, it is "regulation," but it can be structured to utilize aspects of competition within it.

A different regulatory approach to address the planning, construction and ownership of transmission emerged at my former agency, FERC, about a decade ago, and this is the top-down Federal regulatory planning regime supported by opponents of this type of legislation. As part of its "Order 1000" regulation, which was adopted shortly before my tenure, FERC created a new process for certain types of projects. Among the changes, FERC imposed extensive new regional and interregional planning requirements that would be conducted by the Regional Transmission Organizations, like MISO, rather than states or the utilities that serve customers in them. For projects selected under the Federal process, it required a solicitation bureaucracy to determine what projects are selected and which companies own and operate those lines – even though the RTOs own and manage no lines or serve retail customers themselves. Unfortunately, the lines selected under this Federal process might contradict state energy goals, or not be viewed as beneficial to customers by state and local officials. You will not be surprised to learn this has caused significant controversy.

Slow and litigious is a good way to describe the roll-out of this regulation. Projects that are selected must go through a complex bureaucratic solicitation process, and the decisions the RTOs make are subject to challenge by the other developers that were not selected. FERC decides how to allocate costs for these lines. This is an inevitably contentious process and states that are unhappy with the share of costs their customers are forced to pay also litigate.

A report by the analysis firm Concentric noted that these processes add significant time delays to projects. The average Order 1000 solicitation process has taken over 500 days just to move from solicitation to selection. Some have taken well over 1000 days. The RTOs themselves spend millions administering the processes. And that is just the selection process. Actual permitting, construction and placing projects in service can add years more.

One instructive example of these shortcomings is the project known as "Artificial Island" in New Jersey and Delaware. It was first identified by the RTO as early as 2012-2013 as an area that needed a transmission solution. It solicited more than two dozen ideas for alleviating the concern. By 2014 it had changed the technical specs for the project. Later in 2014, RTO staff recommended accepting a solution by one company, which was subsequently challenged by another company. The RTO board delayed selection throughout 2014 – including requesting assistance from FERC's alternative dispute resolution service. By 2015, the RTO Board selected a different project. By 2016, that project had ballooned from approximately $270 million in anticipated costs to a budget of over $400 million. This caused the RTO to go back and re-scope the project – to bring it back down to approximately $270 million. Simultaneously, because the State of Delaware was so displeased with how my former agency proposed to allocate the costs of the project – the legislature got involved – attempting to block the construction of it unless the costs were instead allocated more heavily to New Jersey. New Jersey interests, not surprisingly, objected. The cost allocation litigation took several years to be considered by the courts. This project, which consisted of about 5 miles of transmission line and facilities at each end of it in

New Jersey in Delaware, just finished completion within the past year. One can only wonder how many millions were spent in regulatory and appellate litigation. One of the utility executives involved with this project said in Congressional testimony in 2018 that the "promised efficiency looks more like confusion, controversy and chaos."

This complex Federal RTO-led process is too often a square peg in a round hole in regions like the Upper Midwest. It does not fit the rest of regulatory model that the state has adopted. Wisconsin's process for planning, siting, and constructing transmission has been more straight-forward by comparison and allows for aspects of competition that complement, rather than fight, the manner in which the state has chosen to regulate its electricity sector.

Mr. Chairman and committee members, the traditional transmission planning and procurement process that Wisconsin has used has generally worked well. Passage of this legislation merely confirms that what has worked well will continue. FERC itself acknowledges these types of state laws where they exist, because states have unambiguous authority over the permitting function related to transmission construction and ownership. Similar laws have been adopted by numerous states and they have been uniformly upheld by the Federal courts. I encourage you to support Assembly Bill 892.

WISCONSIN INDUSTRIAL ENERGY GROUP

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To: Assembly Committee on Energy and Utilities

From: Todd Stuart, Executive Director
Wisconsin Industrial Energy Group, Inc.

Re: Opposition to Assembly Bill 892

Date: February 3, 2022

Chairman Kuglitsch and members of the Assembly Committee on Energy and Utilities, thank you for the opportunity to provide comments on Assembly Bill 892. Wisconsin Industrial Energy Group, Inc. respectfully offers these comments on behalf of its members in opposition to AB 892 regarding an incumbent transmission facility owner's right to construct, own, and maintain certain transmission facilities.

WIEG is a non-profit association of 25 of Wisconsin's largest energy consumers. The group has long advocated for policies that support affordable and reliable energy. Since the early 1970s, WIEG has been the premier voice of Wisconsin ratepayers and an engine for business retention and expansion. Each year its members collectively spend more than $400 million on electricity in Wisconsin. Many of these companies have electric bills of over $1 million each month, and it is one of their top costs of doing business.

WIEG and our members join ratepayer organizations like Citizens Utility Board (CUB), taxpayer advocate groups like Americans for Prosperity (AFP) and Americans for Tax Reform (ATR), free market advocates like Wisconsin Institute of Law and Liberty (WILL), and other trade associations representing thousands of Wisconsin employees like Midwest Food Products Association and Wisconsin Cast Metals Association in opposing this legislation.

This bill eliminates competition on the development of large new regionally cost shared transmission projects approved by the Midcontinent Independent System Operator (MISO). Eliminating competition will almost certainly cost Wisconsin businesses and consumers more money. Without competition, there are fewer checks and balances on cost estimates, and no pressure or incentive to curb transmission project costs and prevent cost overruns.

Wisconsin's ratepayers simply can't afford additional cost burdens. High electric rates are effectively a tax on ***all*** Wisconsin homeowners and businesses. Wisconsin's electric rates have been well above the Midwest average since 2003 and continue to be above the national average. Energy inflation is a real issue in Wisconsin.

This is a major concern for our members, employing thousands of Wisconsin taxpayers across the state. With MISO expected to approve $30 billion to $100 billion of transmission projects in the coming months, this proposed change will have negative effects on our state's economy. MISO's cost allocation for these projects will be filed for approval at the Federal Energy Regulatory Commission (FERC) later this month. Wisconsin has historically had between 13% to 15% cost share of regional projects. If a similar percentage of cost sharing is applied to the new MISO projects, then Wisconsin would see billions of dollars in new projects in the coming years.

Transmission costs have been a contributing factor in Wisconsin's persistently high rates. Transmission has steadily grown and now makes up a significant and growing line item on electricity bills in Wisconsin. According to the PSC, transmission costs increased at an annual rate of 4.5% between 2009 and 2018. Based on MISO's expansion plans, we have no reason to believe there will be any diminished rate pressure from the growth in capital expenditures related to transmission.

The Public Service Commission (PSC) has supported transmission competition at MISO because competitive bidding serves the public interest and promotes compliance with FERC Order 1000. Multiple regulatory and consumer agencies, including National Association of Regulatory Utility Commissioners (NARUC) and National Association of State Utility Advocates (NASUCA) filed comments last year related to FERC Order 1000 in support of competition.

President Trump's Department of Justice said that bills like AB 892 will increase costs, reduce reliability and harm consumers. The Trump administration commented on the Texas version of AB 892: *"such laws can similarly reduce competition and thereby harm consumers... consumers may face higher electricity rates and less reliable service as H.B. 3995 [the Texas version of AB 892] may limit construction of transmission that would increase the supply of generation available to serve a local territory or area."*

According to studies by the Brattle Group, competition to build regional transmission projects drives cost savings between 20% - 30%, and when cost overruns by incumbent utilities are factored in, the cost savings are estimated closer to 50%.

Real world examples demonstrate how competition can spur innovation and create savings for customers. Duke Energy and ATC (DATC) have a joint venture company to build, own and operate transmission lines in North America. DATC owns Path 15, which is an 84-mile, 500 kV project in California. Path 15 was completed on time and under budget at a cost of approximately $250 million, 18% below the incumbent utility's $306 million initial cost estimate.

Within the MISO footprint, there have been projects that show the benefits of competition. The Duff-Coleman Project in Indiana and Kentucky was the first FERC Order 1000 competitive solicitation. There were 11 proposals for the approximately $60 million project, including multiple MISO transmission owners and transmission owners from other regions competing outside their service territory. DATC and Xcel Energy bid on the project. The winning bid had financial concessions consisting of cost caps, a reduced return on equity and a guaranteed schedule. It also had a strong use of local partners in its operating and maintenance plan.

Another competitively bid project is the Hartburg-Sabine Junction 500-kV line from Texas to West Virginia. MISO received 12 competitive proposals from 9 separate developers (or groups of developers), including Xcel Energy. MISO noted that 8 of the 12 proposals offered a return on equity cap, and each had a schedule guarantee. There was only one proposal that did not offer any cap or concession.

The schedule guarantees and reduced return on equity are significant long-term benefit to the consumer. These commitments end up being incorporated into binding and enforceable contracts with MISO. In other words, if there are delays or cost overruns, the developer must absorb the financial consequences. If AB 892 were signed into law, these protections are removed and large, regionally cost shared projects default to the incumbent utilities. The excess costs to consumers resulting from the lack of competition would be easily reach into the billions from overruns and/or lack of financial concessions.

Wisconsin has one of the most manufacturing-dependent economies in the country. Our member companies support 35,000 good paying jobs, compete locally, regionally and globally. Energy costs are one of the primary factors considered for retention, relocation or expansion for manufacturers throughout our great state.

Many utility customers, both large and small, are already feeling the impact of double-digit rate hikes on their electric bills effective in 2022. Wisconsin should maintain the right of competition to prevent further energy inflation. Wisconsin needs to preserve all avenues of reducing rates to ratepayers.

WIEG, along with taxpayer advocates, business coalitions, and ratepayer groups, respectfully ask that you oppose AB 892.

AMERICAN TRANSMISSION COMPANY®

MEMORANDUM

TO: Minnesota Senate Energy, Utilities and Telecommunications Committee

FROM: John Garvin, American Transmission Co.

DATE: March 20, 2012

SUBJECT: Senate File 1815

Thank you very much for the opportunity to provide testimony regarding Senate File 1815.

ATC owns, operates, builds and maintains the high voltage transmission system serving portions of Wisconsin, Michigan, Minnesota and Illinois. Formed in 2001 as the nation's first multi-state transmission-only utility, ATC has invested $2.7 billion to improve the adequacy and reliability of its infrastructure. ATC is a $3.1 billion company with 9,440 miles of transmission lines and 519 substations.

ATC is also a national leader in the cost efficient planning, development and construction of high voltage electric transmission facilities. With nearly $3 billion invested in the last 10 years, ATC has a proven track record of building needed transmission as cost efficiently as possible for electricity users.

Senate File 1815, unfortunately, would stifle competition in the development and construction of electric transmission facilities leading to higher costs for electricity users in Minnesota. Unquestionably the competitive free market system in America has benefited businesses and consumers for decades. This same competitive spirit will only benefit Minnesota electricity users when applied to the development, construction, ownership and maintenance of electric transmission facilities.

Senate File 1815 is contrary to the nation's energy policy governing transmission. In July, 2011, the Federal Energy Regulatory Commission (FERC) issued Order 1000. One of the central tenets of Order 1000 is to enable incumbent and non-incumbent transmission developers to compete to build transmission facilities that would provide regional benefits, with the costs shared on a regional basis. In its regional transmission planning process, MISO is proposing that these projects would be designated "Market Efficiency Projects" that provide economic savings and "Multi-Value Projects" that provide public policy, reliability and/or economic benefits. FERC's goal with Order No. 1000 was to encourage the development of the substantial amount of transmission needed to support Renewable Portfolio Standards and reliability among other purposes, and that it be developed in the most efficient and cost effective manner.

Establishing an exclusive right of incumbent transmission owners to construct and own electric transmission lines that connect to facilities of the incumbent provider, as proposed in Senate File 1815, would remove any competition to plan, construct, own, operate and maintain certain transmission facilities that MISO would require to provide within its regional planning process. Yet Minnesota incumbent transmission owners who would be protected from competition inside Minnesota would at the same time be able to compete to develop transmission projects in other states that do not impose ROFRs on the market.

Finally, the legislation would create an "off-ramp" for projects that are included in the MISO regional plan for the state of Minnesota. The projects included in that plan are those determined to be the best solution to address a given transmission need. Senate File 1815 would inappropriately give Minnesota transmission owners the ability to refuse to build a project that is included in a regional plan, and this would conflict with the MISO Transmission Owners' obligation to build.

Today, the transmission grid is a regionally interconnected regional system, not a series of in-state systems. An incumbent transmission owner's ability to veto a project that is included in a regional plan could have cost and reliability impacts both on Minnesota electricity users, as well as users beyond the Minnesota state border.

Public Service Commission of Wisconsin

Ellen Nowak, Commissioner

4822 Madison Yards Way
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PUBLIC HEARING
Assembly Committee on Energy and Utilities
February 3, 2022
Testimony of Ellen Nowak
Commissioner
Public Service Commission of Wisconsin

Chairman Kuglitsch and members of the Assembly Committee on Energy and Utilities:

Thank you for the opportunity to testify today in support of SB 892. I am Ellen Nowak, a Commissioner at the Public Service Commission. I have served in that role since 2011 with the exception of 2018 when I served as Secretary of Administration.

I am testifying on my own behalf and not on behalf of the Commission.

I do not often testify on legislation, viewing the Commission as a creature of the Legislature charged with carrying out the utility regulation you determine. However, given that SB 838 impacts the ability of the state of Wisconsin to regulate its own utility infrastructure in the face of an encroaching alphabet soup of federal and regional entities, I decided to speak out.

As a utility regulator, I must balance the interests of all consumers - industrial, commercial and residential - against the financial health of the utilities that, in exchange for regulatory oversight, have a duty to serve every customer in their defined territory. The affordability, reliability and resilience of the services provided by Wisconsin's utilities is at the core of every decision I make.

I understand the impact unreasonably high rates or an unreliable grid has on Wisconsin's customers. But this legislation isn't about rates, it is about reliability and construction costs which make up around 10% of a customer's bill. Any suggestion that turning over the decision as to who builds critical infrastructure in Wisconsin to out of state bureaucrats or the federal government will save money is false.

What this bill does is protect Wisconsin's ability to have a say in who owns and maintains critical infrastructure in our state. Wisconsin residents and businesses have a reliable transmission grid due, in large part, to the system we have in place now. Forfeiting Wisconsin's ability to determine who can build here and replacing our process with a slow, cumbersome bureaucratic process run by the federal government or an arm of the federal government is not in the best interest of Wisconsin. *Who* owns the transmission and builds it here matters. It matters for economic reasons, health reasons and safety reasons. Wisconsin, not out of state bureaucrats or the federal government, should make those decisions because we know what is best for our state.

Preserving a state's ability to make decisions about transmission development is not a partisan issue. The National Association of Utility Regulators, the entity that represents all state utility commissioners – a diverse group – was united in its opposition to the portion of the federal infrastructure bill that allows the FERC and Department of Energy to pre-empt state siting jurisdiction and grants eminent domain powers as they relate the siting certain electric transmission projects. The real question is: Does the federal government, via FERC by itself or through the rules it imposes on its regional transmission organizations including MISO, know what is best for the citizens of Wisconsin? If not, then we should jealously protect the right of Wisconsin to decide what is best for Wisconsin.

This bill also preserves the existing competitive process for determining the costs associated with construction of transmission lines. Under current law, a transmission provider that owns the project competitively bids the construction process, many of which are completed by other Wisconsin companies. PSC staff thoroughly review costs for reasonableness. As Commissioners we also review the costs, cap the costs, impose environmental and financial conditions on the project, set timelines for construction and maintain enforcement over the permit – all under the transparent view of the citizens of

Wisconsin. Our permitting process allows for ample participation by the public and intervenors at every step.

The transmission system is one of the most heavily regulated components of the bulk electric power system. The notion that this legislation will stifle competition or free market forces is a false choice.

From a larger perspective, this bill will not change the status quo for the vast majority of lines being built in Wisconsin or in the MISO region. Many of those lines are already subject to a right of first refusal or located in states that have one. FERC's Order 1000, which altered the federal commission's electric transmission planning and cost allocation requirements for public utility transmission providers has not worked. Republicans and Democrats agree on this. Order 1000 was a one-size-fits-all approach to transmission planning that has, by most measures, not achieved its various goals. This is not the first time that a federal mandate has failed to take into account the specific needs and structure of state systems and when that happens, the states often lose.

Finally, the suggestion that there is $100 billion of new transmission on the horizon in our area is wrong. The most recent information from MISO is that it will propose a slate of projects that is one-third of that cost. Also, the projects will be spread out among a 15 state region and most of those projects will not be cost-shared across the region. For the lines that are cost-shared, Wisconsin pays approximately 15%. For example, let's say MISO approves the construction of a new high-voltage transmission line that will start in South Dakota, travel through Iowa and end in Illinois. Under the current cost-allocation methodology, Wisconsin ratepayers will pay 15% of the costs of that line, despite the fact that the line does not touch our state. This is because MISO determines that certain lines have regional benefits and must be cost shared by the entire region. Interestingly, in the example I provided, Iowa and South Dakota have passed legislation similar to SB 838. Those states have determined that it is in their best interest to know who is building in their state rather than outsource that choice. As the generation resource portfolio is changing rapidly, the need for transmission to accommodate and adapt to those changes is growing. It should not be surprising that some states passed right of first refusal legislation so that they can maintain a voice in the energy transition. Wisconsin should do the same.

I hope that this testimony has clarified the purpose of this bill. Energy regulation, transmission construction, and cost allocation are highly technical and complex processes and systems. It is important that Wisconsin maintain its voice in who owns and builds here in order to preserve reliability while maintaining the competitive construction process.

Because I believe that we must place a premium on the reliability of Wisconsin's transmission system – the success of our economy and health of our citizens demands it – I support this bill. My colleagues and I will continue to vigorously review each case on its own merits and consider the testimony from all parties in order to make a decision that is in the best interests of Wisconsin. Wisconsin cannot afford to sacrifice more control to unelected bureaucrats of the federal government and regional organizations that your constituents have never heard of.

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Testimony in opposition to Assembly Bill 892 from:
Josiah Neeley, Texas Director, R Street Institute

February 3, 2022

Assembly Committee on Energy and Utilities

Chair Kuglitsch and members of the committee,

My name is Josiah Neeley. I am a senior fellow with the R Street Institute, a center-right, free market think tank that supports limited effective government in many areas, including the electricity market. This is why Assembly Bill 892, which would grant incumbent transmission utilities the right of first refusal (ROFR) to build and operate new transmission projects, is of special interest to us. There are several points I'd like to emphasize with respect to this legislation.

First, Assembly Bill 892 is anti-competitive and bad for consumers. The bill would give an incumbent utility the authority to insulate itself from competition for transmission projects. These state-sanctioned monopoly utilities operate under cost-of-service regulation, meaning that the more capital they spend, the more profit they make under government-guaranteed rates of return. Historically, the absence of transmission competition has resulted in a severe lack of economic discipline—leading to cost overruns, with captive consumers footing the bill.

We all know that competition can help keep costs down and spur better service. Think how expensive food would be if you were only allowed to shop at one grocery store. When it comes to building electric transmission, the cost savings from competition can be substantial. For example, the Brattle Group recently studied how competitive transmission projects fared compared to their non-competitive counterparts. For electric transmission projects open to competition, the winning bid averaged 40 percent less than the initial cost estimate for the project, while non-competitive projects historically cost 34 percent more than initial estimates.[1] Transmission costs are already a growing fraction of the price of

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[1] Johannes P. Pfeifenberger et al., "Cost Savings Offered by Competition in Electric Transmission," The Brattle Group, April 2019, pp. 29, 40.

delivering electricity to consumers throughout the country, and up to $100 billion in new transmission projects are expected in the region in the coming years. Wisconsin's electric rates are already above the national average and have been above the average for Midwest state for almost 20 years. Legislation should aim to help alleviate these costs, not add to them.

Second, ROFR requirements can delay needed transmission projects and provoke conflicts with other states. Where incumbent utilities have secured ROFR laws in other states, they have left a wake of deleterious economic results and lawsuits. The concerns even evoked engagement from the United States Department of Justice, which has made clear that state ROFRs reduce competition and harm consumers.[2]

The ROFR backlash has undermined interstate cooperation in developing regional transmission projects, especially in the Midwest. For example, the state of Illinois began to resist paying for the burdens of other states' anti-competitive transmission laws over a decade ago.[3] In deterring regional transmission, ROFR has forced states to forego reliability and economic development benefits. Utilities often circumvent efficient regional projects by breaking up the project into smaller, balkanized and costlier pieces in order to comply with a ROFR law.[4]

Third, Assembly Bill 892 will not affect federal action on competitive transmission requirements. This legislation is being considered during a larger national discussion about the benefits of competition for electric transmission. In 2011, the Federal Energy Regulatory Commission (FERC) unanimously issued its Order 1000, which removed federal ROFR requirements in order to promote greater competition and encourage transmission investment at the lowest cost. FERC is currently considering updating its transmission regulations, and may expand Order 1000 to allow competitive bidding for a greater number of transmission projects. For the purposes of this hearing, it is important to note that nothing in Assembly Bill 892 would or could prevent FERC from acting in this area. It has been an established principle of American law for over 200 years that where state law conflicts with federal laws or

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https://brattlefiles.blob.core.windows.net/files/16726_cost_savings_offered_by_competition_in_electric_transmi s sion.pdf.

[2] "Letter of the U.S. Department of Justice Antitrust Division to the Honorable Travis Clardy," Department of Justice, April 19, 2019. https://www.justice.gov/atr/page/file/1155881/download.

[3] Illinois Commerce Commission v. FERC, 576 F.3d 470, 476 (7th Cir.2009), filed April 13, 2009. https://www.dwt.com/files/uploads/Documents/Advisories/Illinois%20Commerce%20v%20FERC.pdf.

[4] Josiah Neeley, "Right of First Refusal Laws for Electric Transmission are Anti-Competitive in Interstate Commerce," The R Street Institute, June 2021, p. 1. https://www.rstreet.org/wp-content/uploads/2021/06/explainer27-1.pdf.

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regulations, it is the federal law that governs.[5] Indeed, the passage of similar ROFR laws in other states is part of what has motivated FERC to take up consideration of this matter again.

For these reasons, the R Street Institute opposes Assembly Bill 892. Thank you for your time today and I would be happy to take questions.

[5] McCulloch v. Maryland, 17 U.S. 316 (1819).

AMERICANS FOR PROSPERITY
WISCONSIN

TO: Members of the Assembly Committee on Energy and Utilities

FROM: Eric Bott, Director, Americans for Prosperity – Wisconsin

DATE: February 3rd, 2022

SUBJECT: Oppose Assembly Bill 892 - Monopoly Transmission Construction Legislation

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Chairman Kuglitsch and members of the Assembly Committee, thank you for the opportunity to provide feedback on Assembly Bill 892. I regret not appearing in person before the committee; however, prior commitments require me to work out-of-state today.

The stated goal of AB 892's proponents is to preserve state authority over transmission development. While we appreciate the intentions behind this goal, our analysis of the bill's language leads us to conclude the AB 892 will not succeed as hoped.

AB 892 doesn't alter the coordinated planning conducted by the Midcontinent Independent System Operator (MISO) and it can't impact the policies of Federal Energy Regulatory Commission (FERC). Transmission expansion planning is performed by MISO and is subject to stakeholder input and FERC approval prior to going into effect. AB 892 does nothing to alter this situation.

Simply put, the bill fails to accomplish its stated purpose. So, what exactly does AB 892 accomplish? The plain language of the legislation grants a new monopoly to existing utilities in Wisconsin at the expense of Wisconsin employers, our economy, and customers.

Cost Concerns with AB 892

"Competition does a much more effective job than government at protecting consumers." – Thomas Sowell

To say that monopolies tend to drive up prices while reducing quality and that free competition tends to provide converse benefits is as close to a maxim as one will find in economics. There is no magical exemption from these generally applicable and nearly universally accepted principles for transmission line construction. Empirical studies and real-world examples bear this out.

A 2019 study and corresponding follow-up reports from economists at the Brattle Group estimated that competition to construct regional transmission lines drives costs lower by 20% - 30%. Further, when cost overruns on traditionally developed lines are taken into account, potential savings resulting from competition rise to nearly 50%. Keep in mind, the Brattle Group isn't an obscure thinktank or fly by night operation, but rather a well-regarded global economic firm that has worked with more than half of Fortune 100 companies.

Real-world examples of cost savings from competition in transmission construction abound.

Here are but a few:

> **Wolf Creek to Blackberry Line, Kansas** – Coming in at $85.2 million, this 345-kV project was 27% less costly than the next least expensive bid. Operations and maintenance costs were approximately 30% lower.
>
> **Coldwater, Michigan** – Competition contributed to nearly $20 million in savings for consumers. The incumbent ITC revised a $65 million proposed project down to $47 million after competitor GridLiance submitted an alternative proposal that would have resulted in greater reliability at a lower cost.
>
> **Path 15, California** – This 500 kV CAISO project was completed in 2004, 18% below the incumbent's $306 million initial cost estimate.

We must note that the Path 15 project is now largely owned by DATC, a partnership between Duke Energy and ATC, the primary supporter of SB 838. It appears that they want to have it both ways – competition outside of Wisconsin and government protected monopoly status within.

In fact, ATC has a very inconsistent position on competition in transmission construction and legislation like SB 838. ATC Manager of State Government Relations John Garvin previously provided the following testimony when Senate File 1815, legislation similar to SB 838, was up for a committee hearing in Minnesota:

> "Last summer there was a significant event on transmission regarding Order 1000 and in that bill there was an encouragement to seek competition in transmission investments. Now from our perspective, within that bill, within FERC order 1000 they did express a lot of respect for states' rights in particular issues like routing, siting, cost concerns and so on and things of that nature.
>
> "But the thing that causes us the most concern about it [MN's version of SB 838] is that we find it difficult to believe that the FERC would issue an order of this significance while at the same time offering an invitation to state legislatures to pass legislation that would run completely counter to that.

> "So, as I said the state PUC has significant oversight any transmission siting in the state and so I think that is preserved in many, many respects but in terms of the overall concept of competition is good for transmission siting, I think that is something that FERC has recognized. For example the legislation that was passed in the Dakotas, that before Order 1000, that's obviously grandfathered in. I think it's an open question as to whether legislation that is passed subsequent to Order 1000, where that stands."

ATC's written testimony is even more interesting:

> Senate File 1815, unfortunately, would stifle competition in the development and construction of electric transmission facilities leading to higher costs for electricity users in Minnesota. Unquestionably the competitive free market system in America has benefited businesses and consumers for decades. This same competitive spirit will only benefit Minnesota electricity users when applied to the development, construction, ownership and maintenance of electric transmission facilities.

Let's sum up ATC's position. In Wisconsin, they want government to insulate them from competition, but in states like Minnesota, ATC believes that FERC Order 1000 preserves states' rights, that "competition is good for transmission siting," and that bills like SB 838 will lead to, "higher costs for electricity users."

Clearly, a strong public interest exists for allowing competitive bidding on regional transmission projects. Competition lowers costs, increases quality, improves reliability, and provides ratepayers with desperately needed savings.

Legal Concerns with AB 892

Americans for Prosperity – Wisconsin and the ATC of yesteryear aren't alone in coming to this conclusion that a strong public interest exists for allowing competitive bidding.

The Seventh Circuit Court of Appeals, which covers Wisconsin, issued scathing commentary on so-called called Right of First Refusal (ROFR) laws generally:

> No one likes to be competed against. A firm blessed with a right of first refusal can by exercising its option exclude competition with it, in this instance competition in building a new transmission facility. So naturally members of MISO in areas in need of additional facilities oppose Order No. 1000. They want to retain their right of first refusal—they don't want to have to bid down the prices at which they will build new facilities in order to remain competitive. And so while legal challenges to the order eliminating rights of first refusal have already failed, see *South Carolina Public Service Authority v. FERC, supra,* 762

> F.3d at 48–49, 72–82, the MISO transmission owners are trying to prevent the order from applying to them by arguing that FERC must *presume* that their contractual right of first refusal is reasonable.
>
> But why? The owners have made no effort to show that the right is in the public interest. Neither in their briefs nor at oral argument were they able to articulate any benefit that such a right would (with limited exceptions discussed later in this opinion) confer on consumers of electricity or on society as a whole under current conditions.

"The owners have made no effort to show that the right is in the public interest." The same can be said of Wisconsin's incumbent utilities in respect to AB 892, at least when they're in the state of Wisconsin and not in Minnesota.

Legal concerns with monopoly transmission construction legislation or ROFR laws don't begin and end with the Seventh Circuit.

In upholding FERC's original order creating this avenue for competition, the DC Circuit noted that even when incumbent utilities succeed in obtaining projects through the competitive process, "the threat of competitive entry (e.g., through competitive bidding) will lead [incumbent] firms to lower their costs." The circuit continued by noting that ROFRs are, "likely to have a direct effect on the costs of transmission facilities because they erect a barrier to entry: namely, non-incumbents are unlikely to participate in the transmission development market because they will rarely be able to enjoy the fruits of their efforts."

Additionally, President Donald Trump's Department of Justice previously weighed in on state laws like AB 892. The Trump administration commented on Texas's version of AB 892, numbered H.B. 3995, explaining, "such laws can similarly reduce competition and thereby harm consumers," and concluding, "consumers may face higher electricity rates and less reliable service as H.B. 3995 may limit construction of transmission that would increase the supply of generation available to serve a local territory or area."

We believe the Trump administration had it right when they said that a bill like AB 892 will increase costs, reduce reliability, and harm consumers.

Iowa's recently enacted monopoly transmission construction bill is also facing a legal controversy. The legislation, which originally died in committee, was introduced as an amendment to the Omnibus Appropriations Bill at 1:35 a.m. and passed at 5:47 a.m. on the final day of that state's session. Such a process doesn't exactly convey "public interest." Iowa's legislature now faces a lawsuit alleging illegal logrolling occurred in passing this bill.

Versions of AB 892 enacted in other states have faced and are facing credible legal challenges on the grounds that they violate the Commerce Clause of the United States Constitution. With cases maturing in multiple federal circuits, we believe these questions to be ripe for action by the U.S. Supreme Court.

Without a defined public interest in advancing this legislation and strong evidence that AB 892 will harm consumers, why would Wisconsin want to wade into what can only be described as a legal hailstorm?

Conclusion

Americans spend over $1.27 trillion per year on energy. More than 30 million American households face high energy burdens and pay a substantial portion of their take-home pay for electricity, heating, and fuel.

In Wisconsin, the lowest income households devote more than 20 percent of their after-tax income on residential utilities and gasoline. Energy policies supported by President Biden at the federal level and Governor Evers here in Wisconsin are already exacerbating energy poverty.

Governor Evers' appointees on the Public Service Commission recently approved massive rate hikes on Wisconsin consumers, some in the double digits. Our activists have been stunned this month to open skyrocketing utility bills. Local media outlets are reporting that many Wisconsinites are seeing their heating costs increase by $100 or more over the course of a single month.

Over time, the passage of AB 892 will make these problems worse, raising costs on those who can least afford to pay while making our manufacturing sector less competitive nationally and internationally.

This committee and the greater legislature shouldn't follow the Evers administration down its cold path toward greater energy poverty. This committee must reject AB 892.

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February 3, 2022

MEMORANDUM REGARDING RIGHT OF FIRST REFUSAL LEGISLATION

Several states have enacted what are called "right of first refusal" ("ROFR") laws. Assembly Bill (AB) 892 is an attempt to create such a law here in Wisconsin. The Wisconsin Institute for Law & Liberty opposes such legislation for policy reasons as outlined herein. In addition, this memorandum summarizes some of the open legal questions surrounding such legislation.

State ROFR Laws Limit Competition

AB 892 is an attempt to further eliminate what little competition exists in Wisconsin's transmission market. A company that has ROFR protection under AB 892 can block all competition in building a new transmission facility here in Wisconsin. It makes sense why certain companies are here today seeking such protection. If they were forced to compete, it would necessarily mean bidding down prices.

It is important to note that transmission companies do not operate in a "natural" monopoly. Across the nation, transmission companies regularly connect to each other's facilities as part of the larger grid and they do so while competitively bidding against one another. This competitive process ensures that lines are built in an efficient manner, at the lowest cost for ratepayers. In fact, one study by the Brattle Group found that competition can save ratepayers 20-30% on the cost of the project. When coupled with the fact that contracts under the competitive bidding process often include containment measures, thus limiting the potential for overruns, these savings have the potential to grow even more. Considering that the MISO region—where Wisconsin operates—is considering $30 to $100 billion in projects in the coming years, these savings can be substantial. Bottom line, the market can absolutely support more than one firm bidding and building these projects.

The state should embrace this competition and have those firms bid against one another to lower costs which in turn help Wisconsin families. Alternatively, if this bill were to pass, ratepayers could likely expect an increase on their power bills as a result.

State ROFR Laws Have Been Challenged Elsewhere

In addition to the strong policy objections, we have to the elimination of competition which will drive up energy costs on Wisconsinites, we also note that these laws have been challenged elsewhere and their legality is uncertain.

The United States Constitution's commerce clause gives unto Congress the power "to regulate commerce … among the several states …" U.S. Const., Art. 1, Sect. 8, Cl. 3. Caselaw interpreting that provision has established the "dormant" commerce clause – which is the implicit prohibition against states adopting legislation which discriminates against or excessively burdens interstate commerce. Under the Supreme Court's "dormant Commerce Clause cases, if a state law discriminates against out-of-state goods or nonresident economic actors, the law can be sustained only on a showing that it is narrowly tailored to " 'advanc[e] a legitimate local purpose.'" *Tennessee Wine and Spirits Retailers Association v. Thomas*, 139 S.Ct. 2449, 2461 , 204 L.Ed.2d 801 (2019) (citations omitted).

Tennessee Wine is the Supreme Court's most recent dormant commerce clause case, and was a 7-2 opinion striking down a Tennessee law as an unconstitutional discrimination against non-state residents. The Tennessee law that was challenged in that case provided that anyone in Tennessee who wanted to own or operate a liquor store had to first establish an in-state presence – i.e., the state law discriminated directly against out-of-state participants in the market.

It could be argued that AB 892, in a similar way, discriminates against anyone who is not an "incumbent transmission facility owner" – and the legislation defines that term as "a transmission company or transmission utility." AB 892, Sec. 1. The terms "transmission company" and "transmission utility" are already defined in statute. A transmission company is defined, among other things, as a company organized under the laws of Wisconsin. Wis. Stat. s. 196.485(1)(ge). A transmission utility is defined as a cooperative or public utility that owns a transmission facility in the state or provides transmission service in the state. Wis. Stat. s. 196.485(1)(i). In order to qualify under SB 838, you must first establish in-state presence, similar to the law from the *Tennessee Wine* case.

Litigants have challenged two state ROFR laws as violations of the dormant commerce clause. The first challenge, was brought against the State of Minnesota's ROFR law. The eighth circuit in that case upheld Minnesota's law in *LSP Transmission Holdings, LLC v. Sieben*, 954 F.3d 1018 (8th Cir. 2020). The Supreme Court did not grant review.

A second and still pending challenge was brought against the State of Texas' ROFR law. There the case is just awaiting a decision from the Fifth Circuit Court of Appeals. *See* NextEra Energy Capital Holdings, Inc. et al v. D'Andrea, 5th Cir., Case No 20-50160.

Both the Minnesota and Texas challenges were brought by Paul Clement, former solicitor general of the United States. In addition, both the Minnesota and Texas ROFR laws were opposed by the U.S. Department of Justice under the Trump administration. Depending on the outcome of the Fifth Circuit case, there could be a circuit split which would make this issue a prime target for U.S. Supreme Court review.

Conclusion

Using the heavy hand of government to eliminate competition does not benefit Wisconsin families who will have to foot the bill for the added expense. In addition, while legal challenges elsewhere play out, it would be prudent for Wisconsin to set this proposal aside.

Please oppose AB 892.

CUB CITIZENS UTILITY BOARD
Citizens Utility Board of Wisconsin, Inc.
Thomas Content - Executive Director
P.O. BOX 8983 | Madison, WI 53708-8983
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To: Members of the Assembly Committee on Energy and Utilities
From: Tom Content, Executive Director, Citizens Utility Board of Wisconsin
Date: Feb. 3, 2022
Re: Opposition to Assembly Bill 892

Thank you for the opportunity to provide input as you consider passage of Assembly Bill 892. CUB urges you to keep cost saving tools in the regulatory toolbox for customers across Wisconsin and oppose this incumbent monopoly utility protection legislation.

CUB advocates on behalf of homeowners, renters and small businesses across the state — the residential and small business customers of Wisconsin's electric, natural gas and water utilities. CUB is a nonpartisan non-profit organization created by the Legislature in 1979 to level the playing field in cases at the state Public Service Commission. CUB advocates for safe, reliable and affordable utility service.

This bill undercuts efforts to find savings when power lines are built. Consumer advocates and customer groups across the country have mobilized in the name of cost savings to support competitive bidding for projects as part of an expected multi-billion-dollar expansion of the Midwest and national power grid.

Customer savings are paramount. Transmission spending is taking up a larger share of a typical customer's electric bill, and Wisconsin customers pay the second highest electricity rates in the Midwest. Our electricity rates rank among the top 15 most expensive states in the country for residential and business customers.

Competitive bidding has been shown to save up to one-third on transmission line costs. Significantly, cost caps in competitively bid projects assure that utility customers aren't on the hook for cost overruns. Wisconsin utility customers have paid hundreds of millions of dollars in construction overruns for utility projects over the past 10-15 years.

We need every tool in the toolbox to protect customers from unnecessarily high utility bills. CUB partnered with business groups in the past on transmission issues at the Federal Energy Regulatory Commission to bring down the Return on Equity — or profit rate — transmission companies earn. That case helped reduce a profit rate that was above 13% for transmission companies. Utility customers in Wisconsin have seen credits on their bills in recent years because of that action.

At a time when customers across the state are seeing surging natural gas prices on their energy bills, CUB respectfully requests your help in keeping utility costs in check by opposing AB 892.

cleanwisconsin

your environmental voice since 1970

Date: February 3, 2022
To: Assembly Committee on Energy and Utilities
From: Erik Kanter, Government Relations Director, Clean Wisconsin
Re: Please Oppose Assembly Bill 892

Clean Wisconsin is a non-profit environmental advocacy organization working on clean water, clean air and clean energy issues. We were founded over fifty years ago and have over 30,000 members and supporters around the state. We employ scientists, policy experts and attorneys to protect and improve Wisconsin's air and water resources.

We respectfully request that committee members oppose Assembly Bill 892. The legislation undermines the competitive bidding process for transmission projects, which enables monopolistic transmission development to the detriment of ratepayers.

Under current law, the Midcontinent Independent System Operator (MISO) manages the transmission in 15 states, including Wisconsin and the northern Midwest. Interstate coordination of transmission allows energy customers to benefit from diverse energy production by exporting and importing energy across a region. It also ensures the regional grid is sufficiently powered and guides the region's energy future.

MISO is regulated by the Federal Energy Regulatory Commission (FERC), which requires competitive bidding processes for new transmission projects. Senate Bill 838 seeks to preempt this process by allowing an incumbent transmission company to exercise right of first refusal in the development and construction of new transmission within its service territory in Wisconsin. In short, Assembly Bill 892 enables anti-competitive territorial monopolies.

Competitive bidding necessarily leads to lower costs to build projects, which in turn benefits ratepayers. A recent study found winning bids in competitive bidding processes for transmission projects were on average 40 percent lower than the initial cost estimates.[1] In contrast, Assembly Bill 892 threatens to shift escalated project costs incurred by transmission companies onto ratepayers.

Robust competition for construction of transmission lines helps provide clean, affordable energy to residents across the state. Assembly Bill 892 neither streamlines grid connectivity nor lowers energy costs. We respectfully request the committee reject this legislation.

If you have any questions, please contact Erik Kanter at ekanter@cleanwisconsin.org.

[1] Brattle Economists: Competitive Transmission Planning Offers $8 Billion in Potential Consumer Benefits Over Five Years - Brattle