Cost Savings Offered by Competition in Electric Transmission

Experience to Date and the Potential for Additional Customer Value

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Evidence on Cost Savings to Date and the Potential for Additional Customer Value

Numerous studies have presented and discussed the high economic value that regional and interregional transmission investments can provide in the U.S.[1] Nevertheless, seven years after FERC Order No. 1000, major regional investments have been limited and interregional projects are almost non-existent. Advancing competition in transmission can help increase the value of the investments and provide more transparency into transmission costs. Doing so would ultimately increase the attractiveness of strengthening the regional and interregional transmission grid to create a more robust and cost-effective electricity system.

The current level of competition in electric transmission has been very limited. We have identified thirty-one competitive solicitations for transmission projects in ISO/RTO regions, of which 16 occurred in PJM and 10 in CAISO. Overall, the transmission projects subject to competition represent 3% of U.S. nationwide transmission investments between 2013 and 2017. The 3% includes all of the projects that have been selected through competitive solicitations, including projects proposed by incumbent utilities. The limited number of competitive projects is explained by restrictive regional planning criteria that have precluded most transmission investments from being subject to competitive processes. Some of these criteria are set out in Order 1000, limiting competitive processes to regionally cost-allocated transmission projects and excluding local projects.

Based on the experience with competitive projects in the U.S. to date, we estimate that the potential cost savings from expanding competitive processes could range from approximately 20% to 30%, consistent with savings achieved with similar competitive transmission processes in Canada, the U.K., and Brazil. At an estimated cost savings of 25%, the potential customer value from expanding competitive processes from 3% to 33% of all planned U.S. transmission investments would be approximately $8 billion over the course of five years. In addition to cost savings, competitive processes for transmission investments stimulate innovation through

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1 For a summary of various studies see Pfeifenberger and Chang, *Well-Planned Electric Transmission Saves Customer Costs*, June 2016, pp. 5-14. Available at: https://wiresgroup.com/docs/reports/WIRES%20Brattle%20Report_TransmissionPlanning_June2016.pdf

opportunities for transmission developers to propose: (1) innovative technological and engineering solutions to more cost-effectively address identified transmission needs; and (2) cost containment mechanisms that reduce the extent to which customers are exposed to the risk of cost escalations.

We recommend that federal and state policymakers consider the positive experiences with competitive processes to date and expand the scope of competitive transmission investments to capture more of the innovation and cost reductions benefits achieved through competition. Applying more innovative and cost-effective solutions to both competitively- and traditionally-developed transmission projects will support the role that the transmission grid will play in ensuring system reliability, spurring economic development, and integrating renewable generation as the costs of generation and storage technologies continue to decline and the economy transitions to a clean-energy future.

Ultimately, the U.S. will require a more robust transmission infrastructure. Using competitive forces to stimulate innovation and reduce the costs of necessary investments both increases opportunities for transmission developers while providing value to customers.

Growth in U.S. Transmission Investments Have Primarily Been Reliability-Based and Locally-Developed Projects

Investments in electric transmission facilities have grown significantly over the past 15 years in the U.S. As Figure 1 below shows, U.S. transmission companies are now investing approximately $20 billion/year in transmission infrastructure.

This growth was largely in response to a growing need to meet reliability standards, to cost-effectively integrate new generating resources, and to reinforce and replace the aging existing transmission infrastructure—much of which was developed 50–60 years ago during a period of rapid economic expansion and electricity demand growth in the 1960s and 1970s. Regulatory and governmental agencies, such as the Federal Energy Regulatory Commission (FERC) and the U.S. Department of Energy (DOE), have long documented this need to reinforce, replace, and modernize the nation's aging, inefficient, and heavily-congested transmission infrastructure as critical to meeting the future energy needs of the economy.[2]

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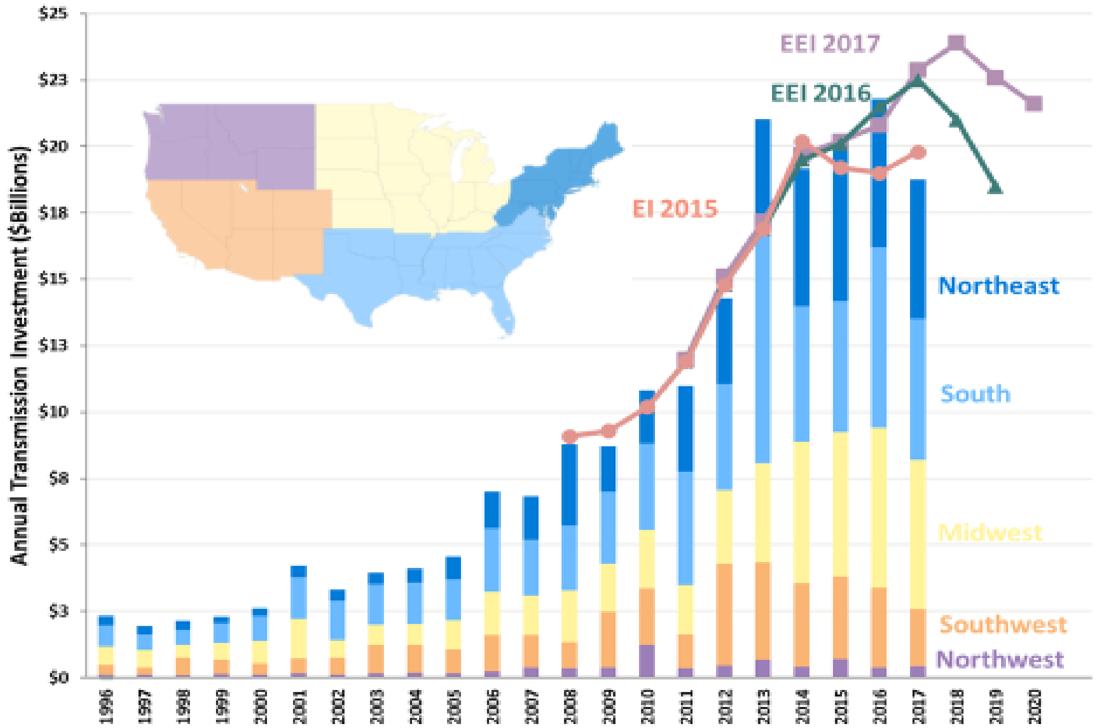
[2] See, for example, U.S. DOE's QER Report: Energy, Transmission, Storage and Distribution Infrastructure, April 2015, p. S-5.

Figure 1
U.S. Annual Transmission Investments
(For FERC-jurisdictional and ERCOT Transmission Owners)



Sources and Notes: Regional Investment based on FERC Form 1 investment compiled in ABB Inc.'s Velocity Suite, except for ERCOT for years 2010–2017, which are based on ERCOT Transmission Project Information Tracking (TPIT) reports. Based on EIA data available through 2003, FERC-jurisdictional transmission owners estimated to account for 80% of transmission assets in the Eastern interconnection and 60% in WECC. Facilities >300kV are estimated to account for 60–80% of shown investments. EEI annual transmission expenditures updated December 2017 shown (2011–2020) based on prior year's actual investment through 2016 and planned investments thereafter.

Overall, every region has experienced growth in transmission investments to meet the various needs of the U.S. electricity industry. The transmission investments within markets operated by U.S. ISOs and RTOs accounted for over 80% of recent transmission investments by FERC-jurisdictional and ERCOT transmission owners.[3] From 2013 through 2017, an average of $17 billion/year of transmission investments were made within the U.S. ISO/RTO regions,

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[3] In 2017, transmission investment within markets operated by U.S. ISO/RTOs was $15.5 billion, compared to $18.8 billion of total transmission investment made by FERC-jurisdictional and ERCOT transmission owners. The 2013–2017 average transmission investment made within U.S. ISO/RTOs was $17.2 billion/year, which compares to $20.1 billion/year average investment made by all FERC-jurisdictional and ERCOT transmission owners during the same period.

Transmission investments outside FERC jurisdiction and ERCOT (*e.g.*, those of public power agencies such as the Tennessee Power Authority, Bonneville Power Authority, or Western Area Power Authority) are not reflected in these transmission investment statistics.

including ERCOT.[4] Since 1999, transmission investments have grown the most within the ISO/RTO regions, ranging from 10% to 16% of average annual growth, compared to 6% to 10% in regions not operated by ISOs or RTOs.[5] Significant investments have been made, but relatively little has been built to meet the broader regional and interregional economic and public policy needs envisioned when FERC issued Order No. 1000. Instead, most of these transmission investments addressed reliability and local needs.

A Robust Transmission Grid Provides Benefits to Customers

The electricity industry is in the midst of major transitions due to significant changes in resource mix, environmental policies, electricity uses, and reliability and resiliency standards. While going through such transitions, the transmission grid continues to be the foundation that maintains reliability for all electricity users, integrates new generating resources, and improves the overall cost effectiveness of electricity service. The continued need for regional transmission investments that provide substantial reliability and economic benefits to all electricity users in the region is clear and continues to be better understood.[6]

Given the amount of transmission investments that are and will be needed across the country, we examine the possibility of advancing competitive processes in developing and constructing new transmission. This report analyzes the potential cost savings offered by competitive processes based on the experience to date and discusses how expanding those experiences could increase the benefits of having a robust transmission system to electricity users. To conduct our analysis, we undertook an extensive effort in collecting data and analyzed the costs of transmission projects to estimate the impacts of competitive processes across the U.S. We also reviewed international experiences with competitive transmission development in the Canadian provinces of Ontario and Alberta, the U.K., and Brazil.

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4 Our analysis covers the years from 2013 to 2017, as explained in greater detail in the body of the report. Total transmission investment data for 2018 is not yet available.

5 In 1999, the seven US ISOs and RTOs invested only $1.6 billion on transmission assets, compared to $15.5 billion transmission investment in 2017. During the same period, transmission investments in the non-ISO/RTO regions grew from $0.7 billion in 1999 to $3.2 billion in 2017. See Figure 5 for more detailed data.

6 See, for example, Southwest Power Pool (SPP), *The Value of Transmission*, January 26, 2016, documenting that benefits of transmission investments have exceeded their costs by a ratio of 3.5-to-1. Accessed here: https://spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf

Seven Years after Order No. 1000 Mandated Competition in Transmission Planning, 97% of U.S. Transmission Investments Occur Outside the Competitive Processes

In 2011, FERC Order No. 1000 sought to promote "more efficient or cost-effective transmission development" by requiring "opportunities for non-incumbent transmission developers to propose and develop regional transmission facilities through competitive transmission planning processes."[7] Despite the Commission's order and the efforts of FERC-jurisdictional regional transmission planning entities to modify their planning processes and tariff structure around cost allocation, only 3% of U.S. transmission investments approved between 2013 and 2017 have been subject to competitive processes that were open to non-incumbents.[8] The 2013-2017 share of competitive projects for individual regions range from none in ISO-NE[9] to 5.1% of total transmission investments in PJM, 6.8% in CAISO, and 7.0% in NYISO. FERC staff's recent assessment of transmission investment metrics shows that there is significant interest from and participation by many transmission developers in competing for the available opportunities.[10]

For the period from 2013 through 2017, competitively-developed projects account for about $540 million of average annual transmission investment, compared to the approximately $20 billion in average annual transmission investments made during the same period across the country.[11,12]

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7 FERC, 2017 Transmission Metrics Staff Report, p. 6, October 6, 2017; also see FERC Order No. 1000: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Final Rule, July 21, 2011.

8 An estimated 3% of U.S. transmission investments approved through competitive processes is derived based on the value of competitive projects approved between 2013 and 2017, though recognizing that these approved competitive projects have not yet been placed in-service. See Figure 6 below for more details.

9 We recognize that several New England states have issued competitive solicitations for renewable and clean energy, which included proposed generation projects that were bundled with dedicated transmission projects.

10 FERC Staff, *2017 Transmission Metrics Staff Report*, October 6, 2017, p. 14, accessed here: https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf

11 See Section VI for the list of approved competitively-developed projects.

12 The $540 million per year average for 2013–2017 does not account for projects approved in 2018 and 2019, including MISO's $122 million Hartburg-Sabine Junction 500 kV transmission line (awarded late 2018), $50 million of projects approved by PJM in its 2018 competitive window, and NYISO's April 2019 approval of the AC Transmission Public Policy projects ($1.230 billion). If we include these projects, the 2013–2019 average is $587 million per year. Of the $20 billion/year of total U.S. transmission investments, $15 billion/year of the average annual transmission investments for 2013–

Transmission Project Eligibility Criteria for Competitive Processes are Restrictive, Reducing the Scope of Competition

The tariffs that specify the rules for transmission planning for each region currently exclude the large majority of transmission investments from competitive processes. We do not see compelling policy reasons for broad limits or having significant differences in criteria used in various regions that directly or indirectly exclude transmission projects from the competitive processes. In addition, limiting competition only to projects that are regionally cost allocated (as specified by FERC Order 1000) creates barriers to realizing the benefits of competition for those transmission projects whose costs are paid for solely by the local transmission users. By building on the full set of experience with competition from across regions, we recommend that federal and state policymakers consider expanding the scope of competitive transmission investments.

Subjecting more transmission investments to competition would stimulate innovation, increase the cost-effectiveness of the investments, and provide greater overall benefits to customers. For example, through its competitive process, MISO was able to increase the estimated benefit-to-cost ratio of its Hartburg-Sabine Junction project in Texas from 1.35 to 2.20.[13] At lower costs, transmission will more frequently provide cost effective solutions to the benefit of both customers and transmission developers. For the local transmission owners that must respond to cost pressures from regulators, applying innovations from competitive processes to reduce the costs of traditionally-developed projects also increases the companies' ability to invest in other valuable technologies to help meet customers' needs.

Significant Investments in Transmission Are Made Without Full ISO/RTO and Stakeholder Engagement in the Planning and Approval of Projects

Our analysis of the available transmission investment data for years 2013 to 2017 shows that about one-half of the approximately $70 billion of aggregate transmission investments by FERC-jurisdictional transmission owners in ISO/RTO regions are approved outside the regional planning

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2017 were made within the six FERC-jurisdictional ISO/RTOs. Including ERCOT, which is not FERC jurisdictional, the estimated average annual transmission investments for ISO/RTOs is $17.2 billion/year.

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

processes or with limited ISO/RTO and stakeholder engagement.[14] Instead, they are based solely on local planning processes of the existing transmission owners with only cursory reviews by the ISO/RTO planners.[15] Since locally-planned projects are not subject to competitive planning requirements under Order 1000, shifting transmission investment away from regional processes reduces the extent to which competitive processes can enhance the overall cost-effectiveness of transmission investments.

Figure 2 below summarizes for 2013–2017: (1) the estimated share of transmission investments placed in-service within various U.S. ISO/RTOs over a five-year historical period that were subject to the full ISO/RTO stakeholder-based regional transmission planning processes; and (2) the share of those investments that have been subject to competitive regional planning processes. As the figure shows, transmission investments not subject to the full regional planning process range from 29% in ISO-NE to 54% in PJM.

In our review of ISO/RTO transmission project cost estimation and cost tracking data, we found substantial differences in the amount of information available across regions. While some regions have implemented transparent project cost tracking mechanisms, some provide very limited cost information. Given that the great variance of project cost reporting and tracking standards makes it difficult to compare cost trends within and across the various planning regions, we recommend that FERC and the ISOs/RTOs consider implementing consistent minimum requirements for project cost reporting and tracking.

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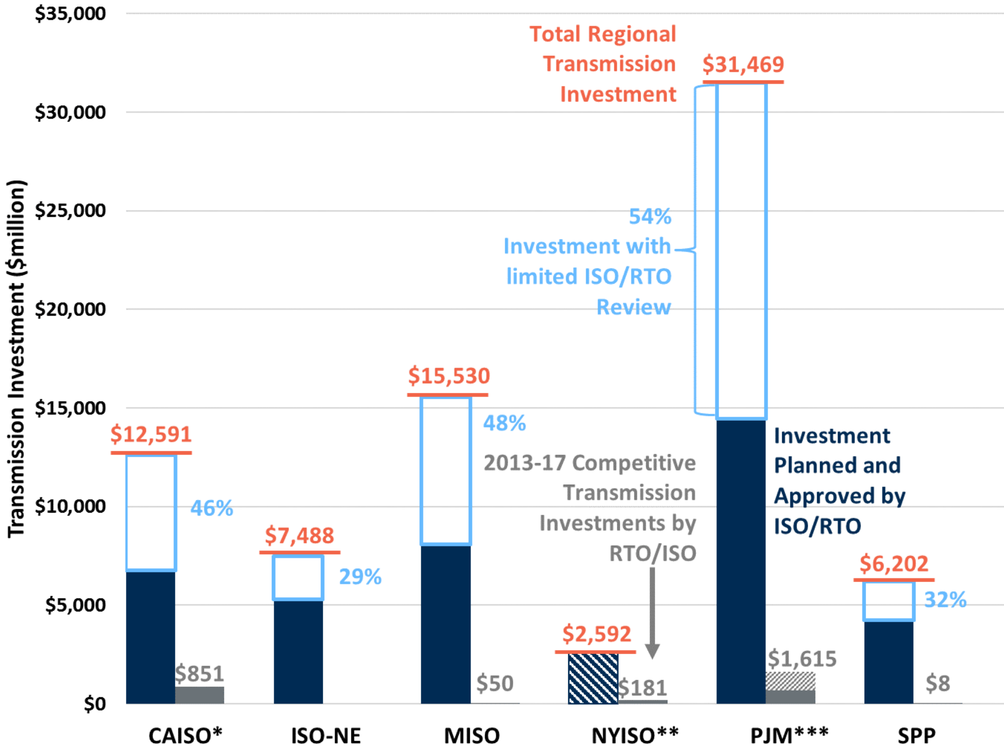
14 The aggregate transmission investment of approximately $70 billion reflects the last 5 years of investments by transmission owners in FERC-jurisdictional ISO/RTOs (2013–2017), with the exception of CAISO (for which transmission investments reflected in the approximately $70 billion is for 2014–2016 only, due to data limitations).

15 This issue has been central in a recent complaint by the California Public Utilities Commission before FERC. See FERC Order Denying Complaint (Docket No. EL17-45), August 31, 2018.

FERC, in response, issued an order denying the complaint and clarifying that transmission activities such as "maintenance, compliance, work on infrastructure at the end-of-useful life, and infrastructure security undertaken to maintain a transmission owner's existing electric transmission system and meet its regulatory compliance requirements" are not considered transmission expansion activities and therefore are not subject to the regional transmission planning and expansion requirements of Order Nos. 890 and 1000. The order (still subject to request for rehearing) confirmed that ISO/RTOs are not required to maintain full oversight on transmission utilities' activities not considered transmission system planning or expansion.

Figure 2
2013–2017 FERC-Jurisdictional Transmission Investments With Full and Limited Stakeholder Review within ISO/RTO Regional Planning Processes



Notes:
*CAISO Investment Planned and Approved by ISO percentage reflects data for 2014 through 2016. Percentages have been applied to total CAISO Transmission Investment over the 2013–2017 period. Data reflects transmission additions/approved investments of only PG&E, SCE, and SDG&E.
**NYISO investment reflects total investment throughout the market because data on Investment Planned and Approved by NYISO is not available. NYISO competitive transmission investment only accounts for the Western NY Public Policy project that was announced in 2017, but not the $1.230 billion AC Transmission Public Policy projects approved in April 2019.
***We have identified only three competitive PJM projects awarded to non-incumbent developers, totaling $663 million. PJM additionally awarded through its competitive solicitation windows 136 projects worth $952 million to incumbent transmission developers; few of these were open to non-incumbent participation because 132 of them involved upgrades to existing facilities. (Source: TEAC Project Statistics Presentation, available as part of the January 11, 2018 TEAC meeting materials; PJM presentation at WIRES Annual Meeting 2018)
SPP's values for 2013 and 2017 contain only partial December values, due to data limitations. Total Investment for each ISO/RTO reflects total FERC Form 1 transmission additions over the indicated time period. Investments approved by ISO/RTO exclude locally-planned projects and reflect the total value of transmission additions placed in-service over indicated time period, approved through ISO/RTO processes.

The Experience to Date Indicates that Competitively-Developed Transmission Offers Significant Innovation and Cost Savings for Customers

Of the competitively-developed transmission projects awarded to date, we were able to analyze sixteen transmission projects subject to competition in which cost data is available. On average across the sixteen projects, the selected proposals were priced significantly below the *initial* project cost estimates prepared by the ISO/RTOs or incumbent transmission owners prior to receiving proposals through the competitive process. The low costs of some of the proposals are consistent with the significant interest and participation in competitive processes by numerous market participants as documented by FERC staff.[16] In addition to the low costs, the selected project proposals generally have included cost caps or cost-control measures, which are expected to reduce the risks to ratepayers of cost escalations as the projects are developed and constructed in the coming years.

Since the competitively-developed projects are not yet constructed, we assume they will likely incur at least some level of cost escalations as they advance through the development and construction phases of the projects. We thus analyze a range of potential cost escalations for the competitively-developed projects: (1) projects completed as proposed with no escalation, (2) cost escalation equal to 5-years of inflation, and (3) cost escalation similar to historical average cost escalations for transmission projects.[17] Figure 3 below shows for two regions, CAISO and MISO, the estimated cost range of competitively–developed projects (dark green bars) under these three cost escalation assumptions compared to our estimate of the final costs of the same project if it had been traditionally developed (blue bar) and incurred typical historical escalations from the initial project cost estimates.[18]

If the projects subject to competition could be developed and constructed *without any cost increases*, the estimated *average cost savings could be as high as 28% in MISO and 50% in CAISO* relative to the likely costs of these projects if they had been traditionally developed. Actual cost savings are expected to be smaller given the potential for at least some level of cost escalations. We estimate that overall cost savings of 15% for MISO and 29% for CAISO would result from the competitive processes even if the competitively-developed projects were to experience percentage cost escalations similar to the historical experience with major transmission projects in these regions.

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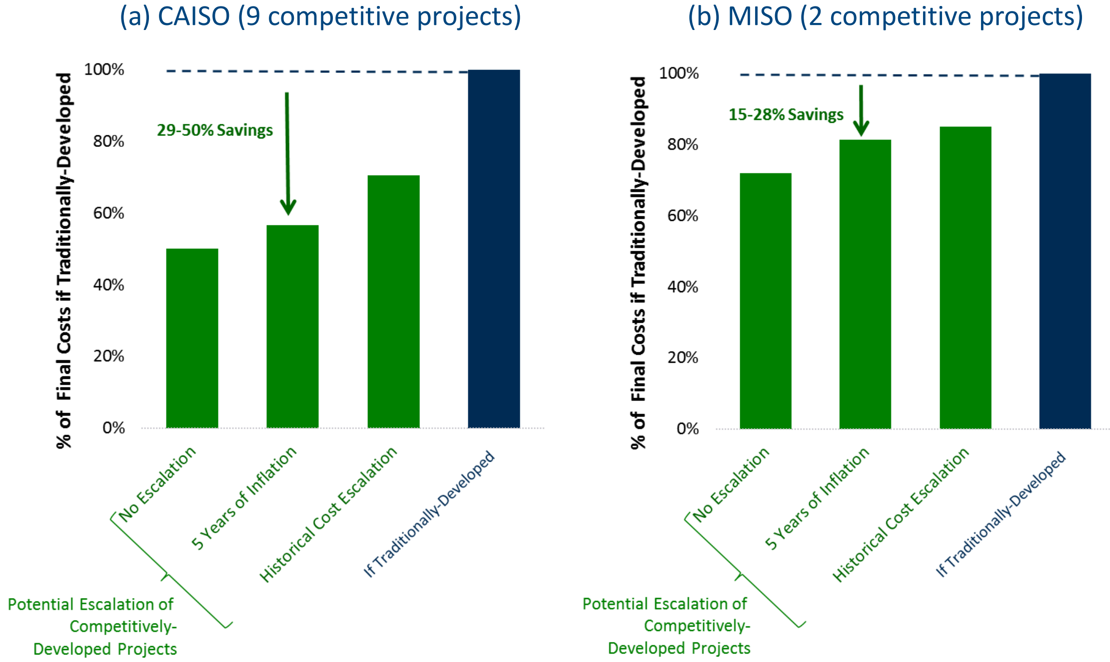
16 FERC, *2017 Transmission Metrics Staff Report*, October 6, 2017, p. 22. Available at: https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf

17 We estimate that, relative to initial estimates, the costs of major transmission projects historically escalated on average by 18% in MISO and by 41% in CAISO. See Appendix A for more details.

18 Only CAISO develops and publishes an initial cost estimate for all transmission projects, allowing for a more direct comparison of the costs of competitively-developed and traditionally-developed projects. Our estimate of potential customer savings for MISO relied on transmission owners' initial cost estimates for estimating average historical cost escalations for transmission projects. These cost escalations reflect factors such as inflation during the often lengthy project development process as well as costs associated with conditions imposed during the siting and permitting process.

Figure 3
Cost Savings for Competitive Projects in Selected RTO/ISOs



Notes: Cost comparisons are based on the actually-reported nominal dollars. Cost escalation in the "5 Year of Inflation" case assumed 2.5% inflation rate and in the "Historical Escalation" case is equal to the historical escalation of major regional transmission projects (41% for CAISO and 18% for MISO).
Source: See Figure 18 in Section IX below.

The range of potential savings in MISO and CAISO assuming some level of cost escalation is consistent with the estimated cost savings from competitive processes in other parts of North America—such as 22% savings in NYISO, 21% in Alberta, and 16% in Ontario—and the already realized cost savings in international markets, which include savings of 23% to 34% in the U.K. and about 25% in Brazil. Based on these experiences with competition to date, we estimate that competitive transmission development processes can be expected to yield cost savings ranging from 20% to 30% on average.

Based on our experience and discussion with industry participants, the cost savings reflected in the selected competitive proposals can be attributed to a wide range of innovative approaches to transmission development. They include innovative project designs, such as using new technologies for conductors, tower type, materials, and foundations; optimized routing to reduce permitting costs; innovative contracting; cost-control mechanisms (such as improved risk sharing with and incentives for the engineering and construction contractors); and innovative partnerships and financial structures, including public-private partnerships to streamline project permitting.

In regions with "solution-based" competitive procurement processes, such as NYISO and PJM, competition can foster significant additional benefits from innovative project design and risk mitigation to address the identified need. For example, in the solicitation process for PJM's Artificial Island Project, many developers proposed a wide range of solutions to meet the identified transmission need. Some developers also proposed innovative lower-voltage design options that addressed all the needs identified by PJM at substantially lower costs and reduced constructability risk. In contrast, other developers offered to include significantly longer circuit-miles and only 500 kV options at significantly higher costs. In NYISO, the solutions-based competitive processes similarly attracted multiple design innovations that yielded lower costs and higher customer benefits.

We see significant value in such "sponsorship" or "solutions-based" approaches to the competitive process because developers are also competing on broader design ideas, which can yield significant additional cost benefits when innovative solutions can more cost-effectively meet identified system needs. While we document significant cost savings for project-based competitive processes, the potential savings are likely to be less because developers are purchasing materials and services from the same market and must meet the project-specific criteria. Thus, to maximize the value of competitive transmission development processes, we recommend moving toward more sponsorship or solutions-based approaches.

The Cost of Competitive Processes

The cost of administering and participating in competitive processes are not trivial, but are relatively small compared to the costs of the transmission projects and the potential cost savings from developing and implementing the competitive processes. Administrative costs associated with the evaluation process are typically assigned to the project developers participating in the competitive processes.

For example, SPP's cost of administering its first competitive process was approximately $500,000—requiring the recovery of $47,000 from each of the eleven respondents and accounting for approximately 3% of the project's $17 million cost estimate, none of which was directly passed through to transmission customers.[19] During 2016 and 2017, PJM spent $1.7 million administering

[19] SPP estimated that developers spent $300,000 to $400,000 to prepare each of the 11 proposals submitted to SPP's solicitation for the North Liberal–Walkemeyer 115 kV project, for a total of $3.3 million to $4.4 million of developer costs. (See *Prepared Statement of Paul Suskie, Executive Vice President and*

five solicitation windows, 97% of which were recovered from the project proponents through fees.[20] The U.K. regulator Ofgem estimated that approximately 4% of large competitive transmission projects' total costs are associated with conducting and participating in the competitive bidding process—with developer costs estimated at 2% of total project cost, the cost of conducting the solicitation at 1%, and the rest incurred by the network owners and system operators.[21]

Developers' costs (including the ISO/RTO administrative charges imposed on them) will ultimately have to be recovered and would thus need to be reflected in the costs of competitively-developed proposals—even if not every developer includes these costs in every proposal and every round of competitive solicitations. As a result, these costs likely are included in competitive project costs and thus already accounted for in the above estimates of cost savings. For individual developers who have gained experience in the processes, we anticipate that their costs will decrease over time as they improve and streamline assembling a competitive proposal. The lessons learned from each process will carry forward and improve the industry's ability to explore innovative techniques in developing transmission projects.

Expanding the Scope of Competitive Processes Could Yield Significant Cost Savings

Increasing the share of transmission investments developed through competitive transmission planning processes is likely to yield significant customer savings. Based on the experience with competitively-developed transmission in the U.S. and other countries, competitive processes are more likely to be adopted for higher voltage and higher cost projects. Of all the recent RTO-planned transmission investment in PJM and MISO (excluding supplemental and transmission owner-initiated projects), about half of all MISO-planned projects and 77% of PJM-planned projects cost more than $25 million.[22] Based on voltage, about half of the investments planned by MISO and PJM have involved voltage levels above 300kV and about 66% have been above 150kV.

General Counsel, Southwest Power Pool, Inc., FERC Docket No. AD16-18-000.) Similar to SPP's costs of administering the competitive solicitation process, these costs are incurred by project developers and will thus tend to be reflected in the proposed project costs.

20 PJM, Competitive Planning Process Proposal Fee Status Update, December 14, 2017, p. 4.

21 Ofgem, *Extending Competition in Electricity Transmission: Impact Assessment*, May 27, 2016, Sections 3 and 4.7.

22 See Figure 20 for more details.

Based on these statistics, and recognizing that a substantial portion of transmission development cannot be open to competition because it involves refurbishment or upgrades to aging existing facilities, it should be possible to expand the scope of competition to cover approximately one quarter to one third of total transmission investments—particularly if the current barriers to the development of cost-effective regional and interregional transmission projects to address market efficiency and public policy needs can be reduced. If competition can reduce costs by 25% on average, the cost savings from competition on one third of the planned U.S. transmission investments would be approximately $8 billion over five years. Figure 4 below shows that these potential cost savings to customers range from a five-year total of $4.4 billion at the low end (if only 25% of U.S.-wide investment was subjected to competition and competitively-developed projects yielded 20% cost savings) to $9.0 billion at the high end (if 33% of total transmission investments were developed competitively and achieved 30% cost savings).

Figure 4
Potential 5-Year Cost Savings from Increasing U.S. Transmission Investments Subject to Competition

Estimated Savings from Competitive Processes (*% of Transmission Costs*)	**20 - 30%**
Estimated 5-year US-wide Transmission Investment (*$ million*)	$100,000
Current Share of Competitive Projects (*% of Total Investment*)	3%
Estimated 5-Year Cost Savings of Expanded Competitive Processes ($ million)	
25% of Transmission Investment Subject to Competition	$4,400 - $6,600
33% of Transmission Investment Subject to Competition	$6,000 - $9,000

To conclude, the experience with competitive transmission processes to date demonstrates that they can attract significant interest from a wide range of transmission developers and have been able to deliver significant innovations and cost savings. Expanding these competitive processes to a larger portion of total transmission investments would magnify the net benefits of the investments and meaningfully reduce customer costs. Developing a larger portion of transmission projects through competitive processes would also benefit transmission owners by reducing rate pressure and increasing the attractiveness of transmission investments as a solution to the challenges of a rapidly-changing energy economy.

I. About this Report

LSP Transmission Holdings, LLC ("LS Power") asked The Brattle Group to undertake an in-depth examination of the experience with competitive transmission. The objective of this report includes assembling available data on the costs of transmission projects in the U.S. and abroad. As a part of this undertaking, we set out to evaluate current experience with competition and discuss whether increasing the scope of competitive transmission in the U.S. would offer meaningful cost savings. In this report, we:

1. Analyze the extent to which transmission investments are fully vetted through stake-holder-driven ISO/RTO planning processes;
2. Examine the use of competitive processes in ISO/RTO transmission planning and solicitation to date;
3. Review the evidence from existing competitive processes in the U.S. and Canada;
4. Assess whether and if so, the extent to which competitively-developed projects are likely to result in cost savings compared to traditionally-developed transmission;
5. Estimate the potential customer benefits that would be achieved by expanding the scope of competition; and
6. Provide selected case studies of U.S. and international experiences with competitive processes.

We have presented a draft summary this analysis at several public forums[23] and obtained valuable feedback from transmission developers, policymakers, regulators, and customer representatives, which we have incorporated in this report. We describe our updated analyses, approach, and findings in this report, with additional detail presented in the Appendices.

II. Historical Transmission Investments in the U.S.

We have previously explained that much of today's transmission grid was built in the 1960s and 1970s, with very limited transmission investments occurring from the mid-1980s through the late 1990s.[24] U.S. investments in electric transmission facilities have grown from approximately

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[23] For example, see 2018 presentations to NARUC and WIRES.

[24] For example, see J.P. Pfeifenberger, J. Chang, and J. Tsoukalis, *Investment Trends and Fundamentals in U.S. Transmission and Electricity Infrastructure*, Presented to the JP Morgan Investor Conference,

$2 billion per year during the late 1990s to approximately $20 billion per year during the last five years. Transmission investments made within regions operated by FERC-jurisdictional U.S. ISO/RTOs and ERCOT account for over 80% (about $17 billion/year) of this recent level of transmission investments. Figure 5 below provides details of these transmission investment levels for 1999 and the period from 2010 through 2017.

To assemble the investment amount, we relied on FERC Form 1 reports for all U.S. transmission owners reporting to FERC and computed total annual investments in "Electric Transmission Plant-in-Service" for each company and each year over the past two decades. We also relied on the Department of Energy's Form EIA-861, which provides information on transmission owners' ISO/RTO affiliations—thereby allowing us to analyze annual transmission investments for each ISO/RTO and non-ISO/RTO region.[25]

July 17, 2015, slide 6, posted at: http://files.brattle.com/files/5916_investment_trends_and_fundamentals_in_us_transmission_and_electricity_infrastructure.pdf

25 Each year, FERC-jurisdictional transmission owners (*e.g.*, electric utilities) file FERC Form 1 reports, which collect financial and operational data from each filing entity. We analyzed these FERC Form 1 reports for all reporting U.S. transmission owners and computed total annual investments in "Electric Transmission Plant-in-Service" for each company and each year over the past two decades. For 2010–2017, our analysis reflects actual annual ISO/RTO affiliations for the FERC-jurisdictional utility. However, since Form EIA-861 includes ISO/RTO membership information only since 2010, our classification of transmission investments prior to 2010 is based on 2010 ISO/RTO membership information. This has the advantage that the significant changes in ISO/RTO members during the first decade of ISO/RTO formation do not distort the investment trends within the specific geographic regions. For non-ISO/RTO utilities analyzed in our study, we identified the utility's NERC region and evaluated investments at the regional stratification. Finally, for ERCOT—a system operator that is not a FERC jurisdictional ISO or RTO—we relied on ERCOT's Transmission Project and Information Tracking (TPIT) reports to document transmission investments within ERCOT. While some transmission owners operating in ERCOT file FERC Form 1 reports, relying on ERCOT's TPIT provides a more comprehensive record of transmission investments.

Figure 5
U.S. Annual Transmission Investments (2010–2017)
(nominal $ billion)

	1999	2010	2011	2012	2013	2014	2015	2016	2017	2013–2017 Total	1999–2017 CAGR
CAISO	$0.33	$1.7	$0.9	$3.5	$3.2	$2.6	$2.5	$2.4	$1.8	**$12.6**	**10%**
ISO-NE	$0.09	$0.7	$0.6	$1.4	$1.8	$1.4	$1.7	$1.4	$1.2	**$7.5**	**15%**
MISO	$0.34	$1.4	$1.0	$1.3	$2.5	$2.7	$3.0	$4.0	$3.3	**$15.5**	**14%**
NYISO	$0.08	$0.5	$0.7	$0.3	$0.4	$0.5	$0.5	$0.5	$0.6	**$2.6**	**12%**
PJM	$0.46	$1.9	$3.4	$2.9	$4.1	$6.6	$7.3	$7.1	$6.4	**$31.5**	**16%**
SPP	$0.11	$0.8	$0.6	$1.2	$1.0	$2.1	$0.9	$1.4	$0.9	**$6.2**	**12%**
FERC-jurisdictional ISO/RTOs	**$1.43**	**$7.0**	**$7.3**	**$10.6**	**$12.9**	**$15.9**	**$15.8**	**$16.9**	**$14.4**	**$75.9**	**14%**
ERCOT	$0.14	$0.8	$1.2	$1.0	$5.3	$0.9	$0.9	$2.0	$1.1	**$10.2**	**12%**
U.S. ISO/RTOs	**$1.56**	**$7.8**	**$8.4**	**$11.7**	**$18.2**	**$16.8**	**$16.8**	**$18.9**	**$15.5**	**$86.1**	**14%**
Other WECC	$0.32	$1.7	$0.7	$0.8	$1.2	$0.8	$1.3	$1.0	$0.9	**$5.2**	**6%**
Southeast & Other	$0.43	$1.3	$1.8	$1.8	$1.6	$1.6	$1.9	$1.9	$2.3	**$9.4**	**10%**
Total Reported to FERC	**$2.31**	**$10.8**	**$11.0**	**$14.3**	**$21.0**	**$19.1**	**$19.9**	**$21.8**	**$18.8**	**$100.7**	**12%**

Source: The supporting data for Figures 1 and 7 show annual transmission investments made by U.S. utilities since the 1990s (see Appendix C).

While the increased investments in transmission provide significant reliability and economic benefits in excess of project costs,[26] the scale of the current level of investments understandably can raise concerns over their impacts on customer costs and the extent to which the investments are being made in a cost-effective manner. The increasing share of transmission costs in retail rates increases the scrutiny by customer groups and state regulators and for that reason we are sensitive to the need to ensure that future investments are made in the most cost-effective manner by increasing transparency in transmission planning, and in the approval and cost-tracking processes

26 For example, see Southwest Power Pool, *The Value of Transmission*, January 26, 2016, which finds that SPP's transmission investments provide benefits that significantly exceed costs with a benefit-to-cost ratio of approximately 3.5-to-1. Accessed here: https://spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf

See also Midcontinent ISO (2014), MTEP14 MVP Triennial Review: A 2014 Review of the Public Policy, Economic, and Qualitative Benefits of the Multi-Value Project Portfolio, September 2014, finding benefit-to-cost ratios of transmission investments ranging from 2.6-to-1 to 3.9-to-1. Accessed here: https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MTEP14%20MVP%20Triennial%20Review%20Report.pdf as discussed later in this report.[27] Efforts such as competitive processes that can unlock greater cost-effectiveness in transmission infrastructure development will have the potential to provide significant additional benefits to customers. Allowing cost savings to be recognized will require a robust and consistent cost tracking approach across the country.

III. U.S. Experience with Competitive Transmission Processes

The Federal Energy Regulatory Commission issued its final rule on Order 1000, creating incentives for regional and interregional planning, and encouraging competition in transmission planning, on July 21, 2011. In Order 1000, the Commission stated that it was "amending the transmission planning and cost allocation requirements established in Order No. 890 to ensure that Commission-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential."[28] One of the main objectives of Order No. 1000 was to increase regional and interregional transmission development. Well-planned regional and interregional transmission projects are needed to facilitate the growth of renewable generation, capture load and generation diversity across larger footprints, reduce transmission congestion, and improve system reliability and resiliency. However, now, seven years after the Commission's Order No. 1000 was issued, much of the transmission development is focused on reliability and local needs, with only a modest increase in regional projects, and no progress in developing interregional projects, to address market efficiency and public policy needs.

Order No. 1000 also sought to promote "more efficient or cost-effective transmission development" by way of increased competition.[29] To achieve that goal, the order set in place rules requiring "opportunities for non-incumbent transmission developers to propose and develop regional transmission facilities through competitive transmission planning processes."[30] FERC staff's 2017 assessment of transmission investment metrics shows that there is significant transmission

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27 The share of transmission costs in retail rates grew from 6% in 2008 to 10% in 2017 based on EEI data.

28 FERC Order No. 1000: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities; Docket No. RM10-23-000; Issued July 21, 2011.

29 2017 Transmission Metrics Staff Report, p. 6, October 6, 2017; see also FERC Order No. 1000: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Final Rule, July 21, 2011.

30 SPP, 2017 Transmission Metrics Staff Report, p. 6, October 6, 2017; see also FERC Order No. 1000: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Final Rule, July 21, 2011.

developer interest in competing for transmission investment opportunities.[31] However, the strong interest by transmission developers has not translated into significant competitive opportunities. Between 2013 and 2017, only an estimated 3% of the total U.S. transmission investments have been subject to competitive processes.[32] In some regions, such as SPP and MISO, less than 1% of total 2013–2017 transmission investments were subject to the competitive procurement processes established by these ISO/RTOs. In other regions, such as PJM, CAISO and NYISO, shares of competitive projects have been comparatively larger, but still range from only 5.1% to 7.0% of total transmission investments from 2013 to 2017. In ISO-NE and non-RTO regions none of the region's transmission investments have been subject to the regional planning entities' competitive transmission processes to date.[33]

Figure 6 below shows estimated annual investments for competitively-planned transmission by selection year from 2013 through 2017. The 2013–2017 average of annual competitive transmission investments of $540 million/year remains relatively small compared to $20 billion/year average of annual transmission investments in the U.S.[34]

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31 FERC Staff, *2017 Transmission Metrics Staff Report*, October 6, 2017, p. 14,

32 As shown in Figure 6, we estimated the amount of competition relative to total investment by comparing the amount of projects selected in 2013 to 2017 to the total investment that occurred in those years. While FERC required compliance with the Order 1000 within 18-months of issuance of order, examining the share of competitive projects during 2013–2017 implicitly allows for a two-year implementation window. For more details see also: https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

33 We note, however, that some of the New England states' competitive generation solicitations have been bundled with transmission projects. This occurred outside the regional transmission planning processes.

34 The $540 million per year average for 2013–2017 does not account for projects approved in 2018 and 2019, including MISO's Hartburg-Sabine Junction 500 kV transmission line ($122 million), $50 million of projects approved by PJM in its 2018 competitive window, and NYISO's 2019 approval of the AC Transmission Public Policy projects ($1,230 million).

Figure 6
Competitively-Developed Projects in FERC-Jurisdictional Regions and Selection Years 2013-2017
(Project costs in nominal $ million)

	CAISO	ISO-NE	MISO	NYISO	PJM*	SPP	Non-RTO	Total
2013	$144	$0	$0	$0	$0	$0	$0	$144
2014	$148	$0	$0	$0	$90	$0	$0	$238
2015	$425	$0	$0	$0	$912	$0	$0	$1,337
2016	$133	$0	$50	$0	$471	$8	$0	$662
2017	$0	$0	$0	$181	$142	$0	$0	$323
Total Estimated Competitive Project Costs Selected in 2013-2017	**$851**	**$0**	**$50**	**$181**	**$1,615***	**$8**	**$0**	**$2,705**
Total Reported FERC Form 1 Transmission Investment in 2013-2017	$12,600	$7,500	$15,500	$2,600	$31,500	$6,200	$14,600	$90,500
Total Estimated Competitive Project Costs Selected in 2013-2017 (% of 2013-2017 Total Investment)	**6.8%**	**0.0%**	**0.3%**	**7.0%**	**5.1%***	**0.1%**	**0.0%**	**3.0%**

Notes: In addition to these regions, ERCOT accounts for another $10.2 billion of transmission investments for 2013–17.
* In estimating the total costs of competitive projects approved in PJM, we include 136 projects awarded under competitive windows to incumbent transmission owner with total costs of $952 million, of which 132 projects are upgrades to existing facilities that were not open to competitors.

IV. State of Competition in U.S. Transmission Planning

To examine why competition in transmission planning has remained limited to only 3% of investments, we reviewed the FERC-jurisdictional ISO/RTOs' tariffs and business process manuals and compiled the key eligibility criteria and types of exclusions that limit the scope of competitive processes. We find that the criteria and exclusions vary considerably across ISO/RTOs as summarized in Figure 7 below. This review of the various competitive transmission processes highlights that five of six FERC-jurisdictional ISO/RTOs allow competitive transmission planning to various degrees for three major types of transmission projects or needs: (1) Reliability Projects, (2) Economic or Market Efficiency Projects, and (3) Public Policy Projects.

Figure 7
Competitive Transmission Project Eligibility for U.S. ISO/RTOs

	CAISO	ISO-NE	MISO	NYISO	PJM	SPP
Types of Projects Eligible for Competition	Reliability, Economic, Public Policy	Reliability, Economic, Public Policy	Market Efficiency, Multi-Value (MVP)	Reliability, Economic, Public Policy	Reliability, Economic, Public Policy	ITP, High Priority, Interregional
Exclusions						
Exclusions for Reliability Projects		√ (Based on Need Date)	√*		√ (Based on Need Date)	√ (Based on Need Date)
Exclusions for Local Cost Allocated Projects (per Order 1000)	√	√	√	√	√	√
Exclusion of Upgrades (per Order 1000)	√	√	√	√	√	√
Exclusions Based on Voltage						
Voltage > 300 kV						
Voltage 200-300 kV			√** *(For MEP)*			
Voltage 100-200 kV	√		√** *(For MEP)*		√***	
Voltage < 100 kV	√	√	√**		√***	√

Notes: Additionally, competitive transmission may be precluded in certain states, due to state Right of First Refusal (ROFR) provisions.
*In MISO, projects that are only classified as Baseline Reliability Projects are locally allocated (regardless of voltage), making them ineligible for competitive processes. Projects designated as Baseline Reliability Projects and MEPs/MVPs are cost-allocated as though they are MEPs/MVPs.
**MISO limits competition to MEPs and MVPs; MEPs must have a total cost of at least $5 million and a minimum voltage of 230 kV; MVPs must have a total cost of at least $20 million and a minimum voltage of 100 kV; see MISO Tariff Attachment FF, Sections II.B, and II.C.
***PJM has exceptions to these exclusions on lower voltage facilities for specific types of reliability violations. These exceptions are detailed in PJM Manual 14F Section 5.3.4.

As shown in the figure above, in some cases, certain transmission projects may not be eligible for competitive processes if their operating voltages are below a defined voltage level. As also as shown in the figure, applying the competitive processes only to regionally-planned transmission projects, consistent with Order No. 1000, the ISO/RTOs exclude from competitive processes all projects needed for "local" reliability or that rely strictly on local cost recovery. This rule has an unintended consequence. For example, MISO only applies its competitive process to multi-value projects that are above $20 million and 100 kV and market efficiency projects that are above $5 million and 345 kV. This is because reliability projects in MISO's footprint are effectively not candidates for the competitive process as their costs are now allocated to the local zones instead of allocated through a regional sharing mechanism. This change in cost allocation has greatly limited the scope of

MISO's competitive process given that reliability projects account for the overwhelming majority of MISO-planned and approved transmission investments.

In addition, Order 1000 does not affect state or local laws or regulations regarding the construction of transmission facilities, including authority over siting or permitting of transmission facilities, and in some cases those laws may work (and, in fact, may have recently been modified) to exclude some projects from competition. The Final Rule issued by the Commission in Order 1000 emphasized that the reforms did not eliminate incumbent transmission owner's right of first refusal (under federally-approved tariffs) for upgrades to its own existing facilities.[35] This means that any upgrades to existing facilities are currently excluded from competitive processes. While excluding upgrades to existing facilities is consistent with Order 1000, a vague or overly broad application of this clause (or favoring upgrades over potentially more valuable alternative transmission investments) nonetheless limits the region from realizing additional cost-efficiencies through competitive development of transmission.

CAISO and NYISO impose fewer restrictions on the eligibility criteria for transmission projects to enter into the competitive processes, while MISO is the most-restrictive overall. Proportionally, CAISO and NYISO have made a significantly higher share of total transmission investments available to competitive solicitations than the other FERC-jurisdictional planning regions. However, even within the more permissive CAISO and NYISO competitive processes, there are important differences. For example, in New York, the competitive process for the "AC Transmission Public Policy Project" provided for the possibility of non-incumbent developers' utilizing existing utility rights-of-way, thereby enabling broader participation in the process.

The collective experience across these regions shows that competitive processes are feasible for a wide variety of transmission projects, even though certain types of projects may currently be excluded from competitive processes in other regions. For example, given that NYISO and CAISO have successfully implemented competitive transmission planning processes with fewer restrictions, there is not a compelling reason for other ISO/RTOs to apply more restrictive processes than NYISO or CAISO.

In some developers' views, subjecting regionally-planned projects to competition has discouraged transmission companies from suggesting potentially valuable regional projects, anticipating that the projects would need to go through competitive processes and thus could be delayed. Such

35 See FERC Order No. 1000, par. 319.

concerns are legitimate. However, as competitive processes become more common and well-practiced, they should run more smoothly and require less time.

We recommend that the more restrictive processes be reviewed by stakeholders and policymakers and potentially modify the criteria to expand the set of qualifying projects based on the positive experiences in other regions. Taking this step would increase the cost-effectiveness of transmission investments and provide greater benefits to customers. We recognize, however, that doing so may require modifying the requirements of Order 1000, which currently only requires competitive processes for new transmission projects with region-wide cost sharing. This limitation to regional cost-sharing already had unanticipated consequences as shown by MISO eliminating regional cost sharing for the reliability projects (regardless of voltage or investment level), thus effectively eliminating reliability projects from its competitive planning requirements.[36] Opportunities for taking actions that could result in the expansion of transmission projects that can participate in competitive processes exist at both the federal level (including through ISO/RTO stakeholder processes and FERC proceedings) and the state level (to the extent existing state laws serve as an impediment to competition for new transmission investments).

V. Scope of Transmission Investment Oversight

Long-standing FERC policy requires regional oversight of transmission investment in ISO/RTO regions. In Order 2000, FERC declared that each RTO "should have the ultimate responsibility for both transmission planning and expansion within its region."[37] FERC explained that "[t]he rationale for this requirement is that a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels." To gain greater insights into the scope of full ISO/RTO and stakeholder engagement in the planning and approving of U.S. transmission investments within their regions, we analyzed ISO/RTO-reported transmission investment data over 2013 through 2017. From the limited available databases and reports, we identified all transmission projects that have been placed into service and computed the aggregate annual investments using the ISO/RTO-reported final project costs (excluding financing costs during construction). This aggregate annual transmission investment reflects all transmission

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36 Midcontinent Indep. Sys. Operator, FERC Docket ER13-186-000, at PP 3–5 (Oct. 25, 2010) (Order No. 1000 Compliance Filing). See also Midcontinent Indep. Sys. Operator, 142 FERC ¶ 61,215 (2013); both Commissioners Clark and Moeller dissented.

37 FERC Order No. 2000 at p. 486 (slip).

projects that were planned and reviewed fully through the ISO/RTO transmission planning processes. We then compared these ISO/RTO-approved investments to the total transmission plant-in-service additions data for each region as reported in FERC Form 1. This comparison yields an estimate of the share of a region's total transmission investments by FERC-jurisdictional transmission owners that were made with full ISO/RTO and stakeholder engagement during the planning process.[38]

The remainder of the regions' transmission investment is planned by the local transmission owners without full engagement of the relevant ISOs/RTOs and stakeholders. While these investments will be reviewed by the ISO/RTOs to avoid conflicts with regional reliability objectives and added to their planning models, the need for these local projects is generally determined by the local transmission owners and not through coordinated regional planning efforts leading to reduced oversight.[39]

As documented in more detail in Appendix C to this report, our review of ISO/RTO-approved transmission investments relied on annual reports and various data published as part of the ISO/RTOs' transmission planning processes. For CAISO, due to the unavailability of the requisite publicly-reported data, we relied on information obtained from filings in a recent CPUC complaint to the FERC related to transmission spending of PG&E, SDG&E, and SCE utilities.[40] For the other FERC-jurisdictional ISO/RTO regions, we relied on the "Transmission Expansion Plan In-Service" project lists of MISO, quarterly-updated data from "Cost Allocation and Construction Cost" databases of PJM, "Regional System Plan Transmission Cost Tracking Reports" of ISO-NE, and

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38 We recognize that this estimate may somewhat understate the share of transmission investments subject to full ISO/RTO review because the total transmission investment data reported in FERC Form 1 includes AFUDC while the RTO-reported project cost data may not.

39 See FERC Order Denying Complaint (Docket No. EL17-45), August 31, 2018.

As noted earlier, FERC, in response to a formal complaint of California Public Utilities Commission *et al.*, issued an order denying the complaint and clarifying that transmission activities such as "maintenance, compliance, work on infrastructure at the end-of-useful life, and infrastructure security undertaken to maintain a transmission owner's existing electric transmission system and meet its regulatory compliance requirements" are not considered transmission expansion activities and therefore are not subject to the transmission planning and expansion requirements of Order Nos. 890 and 1000. The order confirmed that ISO/RTOs are not required to maintain full oversight on transmission utilities' activities not considered transmission system planning or expansion.

40 Formal Complaint of California Public Utilities Commission, *et al.* (Docket No. EL17-45).

"Transmission Expansion Plan" reports of SPP.[41] Our analysis was not able to cover NYISO, which does not publish cost information on approved projects. We excluded ERCOT due to similar data limitations and its non-FERC-jurisdictional status.[42]

Our analysis of the available transmission investment data for those five years for FERC-jurisdictional ISO/RTOs show that roughly one-half of the approximately $70 billion of total ISO/RTO transmission investments by FERC-jurisdictional transmission owners have been made without full ISO/RTO and stakeholder engagement during the planning process. This finding indicates that about one-half of FERC-jurisdictional transmission investments are made based on local planning processes with only limited ISO/RTO review and stakeholder input, limiting the scope of regional planning under Order 2000 and effective regional coordination of transmission planning to identify least-cost solutions that meet the identified needs. Limited stakeholder engagement leads to a lack of transparency in properly assessing the relative costs and benefits of various transmission projects being developed by transmission owners, and may not entail developing the most effective and cost-efficient transmission solutions for identified needs. To control costs of transmission development, having greater review of the transmission projects would be useful. Acknowledging that adding ISO/RTO and stakeholder review could slow down certain projects' development timeline, we recommend that, at minimum, the ISOs/RTOs should have detailed project tracking mechanism that consistently document project cost estimates at various stages of the project, particularly when the project needs are first identified and at the completion of the projects.

Figure 8 below summarizes the estimated shares of transmission investments placed in-service within various U.S. ISO/RTO regions over the 2013-2017 period. This figure includes projects that were subject to the ISO/RTOs' full stakeholder-based transmission planning and approval processes. As the figure shows, the share of transmission investments subject to the full ISO/RTO regional planning processes ranges from 71% in ISO-NE to 46% in PJM. Across the five ISO/RTO regions for which data is publicly available, approximately 53% of all transmission investments within the regions are subject to the full ISO/RTO regional planning processes and therefore,

[41] See sources in Appendix C.

[42] Given that ERCOT is not a FERC-jurisdictional ISO, not all ERCOT participants file FERC Form 1 reports and our sources for transmission investment within ERCOT come solely from ERCOT. We are unable to analyze the extent to which local transmission owners invest in transmission that is not subject to ERCOT planning and reporting. We attempted to examine the Monthly Construction Progress Reports that ERCOT filed with the Texas Public Utility Commission (PUC), but in 2008 the PUC stopped publishing EXCEL format summaries of these reports.

almost half (47%) of all transmission investments in these ISO/RTO regions are not subject to the full ISO/RTO planning process and associated stakeholder review.

Figure 8
Transmission Additions Subject to Full ISO/RTO Planning Processes

Region	Years Reviewed	FERC Jurisdictional Additions by Transmission Owners (nominal $million) *(based on FERC Form 1 Filings)*	Investments Approved Through Full ISO/RTO Planning Process (nominal $million)	% of Total FERC Jurisdictional Investments Approved Through Full ISO/RTO Planning Process	% of Total FERC Jurisdictional Investments With Limited ISO/RTO Review
CAISO*	2014–2016	$7,528	$4,043	54%	46%
ISO-NE	2013–2017	$7,488	$5,300	71%	29%
MISO	2013–2017	$15,530	$8,068	52%	48%
NYISO	2013–2017	$2,592	n/a	n/a	n/a
PJM	2013–2017	$31,469	$14,458	46%	54%
SPP	2013–2017	$6,202	$4,226	68%	32%
Total		**$70,810**	**$36,095**	**53%**	**47%**

Notes: % of Total FERC-jurisdictional transmission investment approved through full ISO/RTO planning process is calculated as share of total investments by FERC-jurisdictional transmission owners in each region.
*CAISO data only reflects transmission additions/approved investments of PG&E, SCE, and SDG&E.
See Appendix C for detailed sources and notes.

The introduction of competitive processes coincides with substantial increases in locally-planned transmission that are outside the full regional planning processes. As an example, in PJM, the value of regionally-planned "baseline" projects significantly exceeded the value of locally-planned "supplemental" projects prior to the 2014 introduction of competitive windows. Since 2014, however, the value of supplemental projects has increased substantially and now significantly exceeds that of regional baseline projects.[43] Coinciding with this decline in PJM's share of regionally-planned baseline projects, the share of baseline projects eligible to participate in PJM's competitive processes has declined as well. For example, the value of projects eligible for competition has declined from $912 million and $471 million in 2015 and 2016 to $142 million and $50 million in 2017 and 2018. At the same time, the value of projects *not* eligible for competition increased from $1,140 million and $290 million in 2015 and 2016 to $3,092 million and $2,020 million in 2017 and 2018.[44]

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43 PJM, TEAC Project Statistics, January 10, 2019, slide 6. Available at: https://www.pjm.com/-/media/committees-groups/committees/teac/20190110/20190110-project-statistics-2018.ashx

44 *Id.*, slide 16.

In addition to finding that significant shares of the overall transmission investments are not currently subject to full regional planning processes, we faced significant difficulties in accessing cost information on approved projects. The scope of publicly-available ISO/RTO cost tracking and reporting information varies significantly across the regions even for the projects that are subject to the full ISO/RTO planning process. While not all databases are always updated, MISO and SPP currently maintain a transparent cost recording and tracking processes for projects approved thorough their regional planning processes. The transmission project cost reporting and tracking information available for the other ISO/RTO areas is more limited.

For transmission projects planned by the local transmission owners that are *not* subject to full ISO/RTO regional planning review, we are unable to find a centralized place that tracks the costs of these transmission projects. For example, while PJM administers multiple cost-tracking databases, those databases do not provide updated cost information on investments made by transmission owners outside the full PJM regional planning process (*i.e.*, the "Supplemental and TO-Initiated Projects" in PJM). These projects are not developed with active engagement of PJM or its stakeholders, and a lack of cost tracking and reporting makes it difficult to assess whether these investments are being made in a cost-effective manner. In the case of NYISO and CAISO, we find that there are no standardized, regularly-updated public-reporting processes to track and report current and final project costs even for the ISO-approved transmission projects.

Given that the great variance of project cost reporting and tracking standards make it difficult to compare cost trends within and across the various ISO/RTO areas, we recommend that FERC and the ISOs/RTOs consider implementing consistent minimum requirements for project cost reporting and tracking.

VI. North American Competitively-Developed Transmission Projects

Since 2013 (two years after Order 1000 was implemented), FERC-jurisdictional ISO/RTOs have completed 31 competitive transmission procurement processes, as summarized in Figure 9 below: sixteen by PJM, ten by CAISO, two by MISO and NYISO, and one by SPP.[45] CAISO, MISO, and SPP have employed bid- or project-based competitive processes in which transmission developers submit proposal for an ISO/RTO-defined project scope. In contrast, NYISO and PJM employ sponsor- or solutions-based competitive processes in which transmission developers "sponsor"

45 PJM's Artificial Island and several of the early CAISO competitively-developed projects were not subject to Order 1000.

specific project configurations as solutions to address ISO/RTO-identified transmission needs. We discuss experience in non-ISO/RTO regions in Section XI.

Figure 9
Experience with Competition in FERC-Jurisdictional ISO/RTO Regions Since 2013

ISO/RTO	Processes Completed	Process Type	Awards
CAISO	10	Projects	10
MISO	2	Projects	2
SPP	1	Projects	1
PJM	16	Solutions	139
NYISO	2	Solutions	3
ISO-NE	0	Solutions	0
All Regions	**31**		**155**

Even within the limited set of projects subject to competition, transmission developers have shown significant interest across ISO/RTO regions. Over the 2013–2017 period, PJM received 794 project proposals in 16 competitive solicitation windows, with non-incumbent transmission developers submitting 46% of these proposals.[46] PJM approved 139 projects, 132 of which were upgrades to existing facilities that excluded non-incumbent participation.[47]

We briefly reviewed the experience with competitive transmission in ERCOT. While ERCOT is not a FERC-jurisdictional system operator and thus not subject to FERC Order 1000, it has had experience with competition in transmission investments when the Texas State Legislature mandated that the Public Utility Commission of Texas (PUCT) develop the Competitive Renewable Energy Zones (CREZ) transmission projects. The PUCT conducted a competitive selection process but did not require cost-based proposals. The PUCT simply designated both incumbent transmission owners and non-incumbent transmission developers to construct different portions of the CREZ transmission system. No other competitive processes have been used in ERCOT since the development of the CREZ projects.

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46 PJM's 2018 Window 1 has resulted in the award of one project to Dominion with a cost of less than $1 million, which was approved by the PJM Board in February 2019. See: PJM, Regional Transmission Expansion Plan 2018, February 28, 2019, p. 27. Available at: https://www.pjm.com/-/media/library/reports-notices/2018-rtep/2018-rtep-book-1.ashx?la=en

47 See PJM's presentation at WIRES Annual Meeting 2018: http://wiresgroup.com/docs/WIRES%20Meeting%20Materials/2018%20WIRES%20Annual%20Mtg_Craig%20Glazer.pdf

Figure 10 below includes a list of competitive projects across the U.S. and Canada and shows the selected developer for each of them.

Figure 10
North American Competitive Transmission Projects Summary

ISO/RTO	Project	Year of Decision	Selected Developer	Award to Incumbent?
CAISO	Gates-Gregg project (subsequently cancelled)	2013	PG&E/MidAmerican w/ Citizen Energy	Yes
CAISO	Imperial Valley Project	2013	Imperial Irrigation District	No*
CAISO	Sycamore-Peñasquitos 230 kV	2014	SDG&E w/ Citizen Energy	Yes
CAISO	Delaney-Colorado River Project	2015	DCR Transmission	No
CAISO	Estrella Substation Project	2015	NextEra	No
CAISO	Wheeler Ridge Junction Project	2015	PG&E	Yes
CAISO	Suncrest Project	2015	NextEra	No
CAISO	Spring Substation	2015	PG&E	Yes
CAISO	Harry Allen-Eldorado Project	2016	Desert Link	No
CAISO	Miguel Substation	2014	SDG&E	Yes
MISO	Duff-Coleman 345 kV	2016	LS Power w/ Big Rivers	No
MISO	Hartburg-Sabine Junction 500 kV	2018	NextEra	No
NYISO	Western NY Public Policy Transmission	2017	NextEra	No
NYISO	AC Transmission Public Policy Segment A	2019	North America Transmission and NYPA	No
NYISO	AC Transmission Public Policy Segment B	2019	Niagara Mohawk and New York Transco	Yes
PJM	Artificial Island Project	2015	LS Power	No
PJM	Thorofare Project	2015	Transource	No**
PJM	AP South Market Efficiency Project	2016	Transource w/ BGE and Allegheny Power	No**
PJM	136 Projects Awarded to Incumbents (132 Upgrades)	2014-2017	Various	Yes
SPP	North Liberal – Walkemeyer 115 kV (subsequently cancelled)	2016	Mid Kansas Electric	Yes
AESO	Fort McMurray West 500 kV	2014	Alberta PowerLine Limited Partnership	Yes
IESO	East West Tie Line	2013	NextBridge Infrastructure	No
IESO	Wataynikaneyap Power Project	2015	Fortis Inc.	No

Notes:
* While Imperial Irrigation District (the selected developer of the Imperial Valley project) is the incumbent in the Imperial Valley Region, it is not a CAISO PTO and thus not an incumbent within the CAISO footprint.
** Transource is a joint venture between AEP and Great Plains Energy.

To conduct an analysis of the potential cost impact to customers, we first analyzed the cost of the selected proposals relative to either the respective ISO/RTO's initial cost estimate (MISO, SPP, CAISO,[48] Alberta, and Ontario), or the difference between selected proposals and the lowest cost proposal from incumbents (PJM and NYISO).[49] The differences in competitively-developed project proposals relative to these reference cost levels are summarized for MISO, SPP, CAISO, PJM, NYISO, Alberta, and Ontario in Figure 11 through Figure 15.

As detailed in Appendix A, we compare the final project costs to initial cost estimates for completed major regional transmission projects. In addition, in Section XII, we briefly summarize the experience with competition for transmission projects in the United Kingdom (U.K.) and Brazil.

As shown in the analyses documented in Figure 11 through Figure 15, competitive project costs generally are significantly below the respective reference cost levels. These cost differences are quite significant. In MISO and SPP, for example, competitively-developed projects have been proposed between 15% and 50% below the ISO/RTOs' initial project cost estimates.

In solutions-based bidding processes, where there are not prior cost estimates for the specific project proposals, we compare the selected proposal's costs to the cost of the lowest-cost proposal from the incumbent transmission owner. Certainly these are not exactly the same reference points because they could be completely different transmission projects solving the same problem, but they provide a sense of how the incumbent transmission owners approached the identified transmission needs. For example, the experience with PJM's Artificial Island Project shows that the cost of PJM's selected solution is 60% below the lowest-cost incumbent solution initially submitted. In NYISO, the winning proposal was 22% below the lowest-cost proposal by an incumbent transmission owners.[50] Overall, we observe that competitively-developed transmission projects have been proposed at a cost that, on average, has been about 40% below these reference cost levels.

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48 CAISO provides a range for the cost estimate of both competitively-developed and traditionally-developed projects. Figure 12 shows those estimates for competitive projects. A comparison of CAISO and transmission owner cost estimates for traditionally-developed projects shows that the transmission owner estimates are generally consistent with the high end of the CAISO range. See Table 23 in Appendix A and Table 18 in Appendix C.

49 The PJM and NYISO sponsorship models do not lend themselves to the development of an initial ISO/RTO cost estimate as they do not develop their own solutions. We thus compare the cost of the winning bid to the incumbent transmission developer's lowest-cost bid. The Artificial Island project is the only one we analyzed in PJM due to the lack of availability of cost data for the other projects.

50 In addition to this cost advantage, the winning proposal offered higher NYISO customer benefits than the lowest-cost incumbent proposal, as shown in Table 13 of Appendix C.

As shown in Figure 11 through Figure 15, these competitive proposals have in many cases included cost caps and other cost control measures, which to varying degrees will reduce, though not necessarily fully eliminate cost escalation risks during the course of the projects' development life. For example, while the $103.9 million proposal for MISO's Hartburg-Sabine Junction project was 15% below MISO's estimated project costs (in 2018 dollars), the cost guarantee for the project is set at $114.8 million for the completed project (in future dollars, to include the impact of inflation during the development process).[51] In SPP, many of the proposals in the competitive process for the North Liberal–Walkemeyer 115 kV project included cost caps, even though the SPP-selected project did not have one. Similarly, Alberta's Fort McMurray project was estimated at CAD$1.43 billion or 21% below the AESO's own estimate, but the cost of the winning proposal has since increased to CAD$1.61 billion due to allowances for changes in routing (but which likely would have equally affected the AESO estimate).[52]

Figure 11
MISO and SPP Competitive Projects Summary

ISO/RTO	Project	Year of Decision	ISO Cost Estimate	Selected Proposal ($million)	Selected Proposal vs. ISO Cost Estimate	Cost Containment Offered
MISO	Duff-Coleman 345 kV	2016	$59	$50	-15%	Yes
MISO	Hartburg-Sabine Junction 500 kV	2018	$122	$104	-15%	Yes
SPP	North Liberal–Walkemeyer 115 kV (subsequently cancelled)	2016	$17	$8	-50%	No*

Notes: *While SPP's selected project did not have cost-containment, six of 11 proposals did have some form of cost containment. Within SPP's evaluation methodology, cost containment is one of several potential approaches to reducing project risk that can add up to 50 points (out of a total of 1,000 possible points) to a project's score.
Source: MISO Data from selection reports dated December 2016 (for Duff-Coleman 345kV Project) and November 2018 (for Hartburg-Sabine Junction Project). SPP Data from Recommendation Report dated April 12, 2016.

51 MISO, Hartburg-Sabine Junction 500 kV Competitive Transmission Project, Selection Report, November 27, 2018, p. 5.

52 See Fort McMurray West 500 kV Transmission Project, available here: https://www.aeso.ca/grid/competitive-process/fort-mcmurray-west-500-kv-transmission-project/ (also noting that the submitted proposal included all project-related costs while the AESO estimate only included construction costs)
See also AUC Decision 21030-D02-2017, p. 122, available here: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2017/21030-D02-2017.pdf

Figure 12
CAISO Competitive Projects Summary

Project	Year of Decision	CAISO Cost Estimate*	Selected Proposal ($million)	Selected Proposal vs. CAISO's Estimate*	Cost Containment Offered
Gates-Gregg (subsequently cancelled)	2013	$115–$145	$130	-10% to +13%	No
Imperial Valley	2013	$25	$14	-43%	Yes
Sycamore-Peñasquitos 230kV	2014	$111–$221	$108	-51% to -2%	No
Delaney-Colorado River	2015	$300	$280	-7%	Yes
Estrella Substation Project	2015	$35–$45	$20	-56% to -43%	Yes
Wheeler Ridge Junction	2015	$90–$140	$60	-57% to -33%	No
Suncrest	2015	$50–$75	$37	-50% to -25%	Yes
Spring Substation	2015	$35–$45	$28	-38% to -20%	No
Harry Allen-Eldorado Project	2016	$144	$133	-8%	Yes
Miguel	2014	$30–$40	n/a	n/a	n/a

Notes:

*As shown, CAISO reports a high-low range for many project cost estimates. Because we observe that cost estimates prepared by the local transmission owners for traditionally-developed projects tend to be close to the CAISO's high end of its cost estimates, the high end of the percentage cost difference shown in column 5 above will be more representative for assessing the cost savings from competitive processes.

For Sycamore-Peñasquitos 230kV Transmission Line Project, competitive solicitation originally selected an overhead design but was subsequently changed to an underground design after project was awarded to winning proposal.

Year of Decision, and Cost Containment Offered based on CAISO selection reports, with the exception of the Miguel project. Miguel's selection year and winner per CAISO market notice. Also note that while Imperial Irrigation District (winner of the Imperial Valley project) is an incumbent, it is not a participant (i.e., non-PTO) within CAISO.

CAISO Cost Estimate Range from Estimates reported in selection reports and CAISO functional specification documents.

Winning proposal estimates for Gates-Gregg, Estrella Substation Project, and Suncrest from Approved Project Sponsor Agreements; for Imperial Valley and Harry Allen-Eldorado Project from CAISO selection reports; for Wheeler Ridge Junction and Spring Substation from PG&E's response to data request CPUC-PGE-053 in FERC Docket No. ER16-2320-002; for Sycamore-Peñasquitos 230kV Transmission Line Project from its Approved Project Sponsor Agreement and its CPUC Certificate of Public Convenience and Necessity decision filing; for Delaney-Colorado River Project from its CPUC Certificate of Public Convenience and Necessity application.

Figure 13
Selected PJM Competitive Projects Summary

Project	Year of Decision	Selected Developer(s)	Lowest-Cost Proposal from Incumbent ($million)	Updated Project Cost ($million) (Current Estimate)	Updated Project Cost vs. Incumbent Proposal	Cost Containment Offered
Artificial Island Project	2015	LS Power	$692	$280	-60%	Yes
AP South Market Efficiency	2016	Transource w/ BGE and Allegheny Power	n/a	$328	n/a	No
Thorofare Project	2015	Transource	n/a	$72	n/a	No
136 Incumbent Projects (132 upgrades)	2014-2017	Various	n/a	$952	n/a	n/a

Notes on PJM's Artificial Island Project: Initially, PSEG proposed 14 (of the 26) solutions for Artificial Island, with costs ranging from a low of $692 million to a high of $1.5 billion. Of the 26 proposed projects, only two satisfied the performance criteria specified, so according to the selection white paper "PJM undertook additional engineering review to identify the most effective solution to stated needs, taking into consideration the elements of submitted proposals." PSEG ultimately provided a proposal with an estimated project cost of $277–$285 million, with $221 million in cost containment for specific work. However, this proposed project came only after PJM had analyzed the most effective components of the 26 initial proposals and applied its findings to the existing proposals. Finally, it should be noted that LS Power's winning proposal contains $146 million cost containment for their portion of the project. Adding incumbent substation work to LS Power's competitive portion increases the total cost of the solution to the $263 million to $283 million range. LS Power's cost containment contained fewer exceptions than PSEG's cost containment, which led to the recommendation of LS Power's project. Current comprehensive E&C cost for the PJM's Artificial Island Project awarded to LS Power, including work on incumbent developer's facilities is reported at $280 million.

Figure 14
NYISO Competitive Project Summary

Project	Year of Decision	Selected Developer	Lowest-Cost Proposal from Incumbent ($million)	Selected Proposal Cost Estimate (2017 $million)	Selected Proposal vs. Incumbent Proposal	Cost Containment Offered
Western NY Public Policy Transmission	2017	NextEra	$232	$181	-22%	No
AC Transmission Public Policy Segment A	2019	North America Transmission and NYPA	n/a	$750	n/a	n/a
AC Transmission Public Policy Segment B	2019	Niagara Mohawk and New York Transco	n/a	$479	n/a	n/a

Sources: NYISO, Western New York Public Policy Planning Report, October 17, 2017; NYISO, AC Transmission Public Policy Transmission Plan Report, April 8, 2019.

Figure 15
Alberta (AESO) and Ontario (IESO) Competitive Projects Summary

ISO/RTO	Project	Year of Decision	Initial ISO Cost Estimate	Initial Estimate of Selected Proposal	Updated Estimate of Selected Proposal	Updated Estimate of Selected Proposal vs. Initial Estimate	Cost Containment Offered
AESO	Fort McMurray West 500 kV	2014	$1,800	$1,430	$1,614*	−21%*	Yes
IESO	East West Tie Line	2013	$928	$439	$777	−16%	No

Notes on McMurray West 500 KV Transmission Project:
Initial Cost Estimation is AESO Planning estimate +/− 50% (CAD million) for construction costs only.
Winning Proposal is in 2019 CAD million and includes all project costs. Update reflects current estimate in 2020 CAD million
* For AESO, the updated estimate of winning proposal is shown for information only. The initial cost advantage (*i.e.*, the 21% cost advantage of the winning proposal vs. Initial AESO estimate) is calculated using the initial estimate of winning proposal cost vs. Initial AESO estimate. The updated cost of the winning proposal shown reflects costs associated with finalizing of the project route, which was not finalized at the time of Project award and was not reflected in the AESO's Initial Estimate. Therefore, for cost comparison purposes, it is assumed that the Initial AESO estimate would change similar to the change in the selected proposal cost to reflect the finalized route.
Notes on East West Tie Line:
Initial Cost Estimation is incumbent proposal with comparable design as winning proposal in 2020 CAD million.
Winning proposal is in 2012 CAD million. Updated Cost Estimate reflects current estimate in 2020 CAD million.

VII. Case Study: MISO's Experience with Competitive Projects

While competitive processes can significantly reduce customer costs based on the relatively low costs of the selected proposals, the benefits go beyond cost savings. The results of MISO's first two competitive solicitations show competition produced advanced project due diligence, risk reduction, and increased cost certainty for customers by the time that the selection process is complete. Thus, the competitive process effectively facilitated careful risk assessment and mitigation upfront, allowing the ISO/RTO to gain visibility into how developers arrange for the best plans for project engineering, siting, and construction, thereby providing a more robust project cost estimate that the developers are willing to uphold.

MISO conducted two competitive processes since 2016 and both were successful in attracting significant interest from transmission developers. The developers identified lower-cost solutions and proposed approaches to reducing the impact of possible cost escalations on transmission customers. For example, in discussing the results of its first competitive solicitation, the Duff-Coleman 345 kV project in Indiana and Kentucky, MISO highlighted the "dedication, innovative thinking, and competitive spirit" of the respondents that will "benefit MISO, its members, and ultimately all consumers of electricity in helping us build a stronger and more reliable electric grid for today and tomorrow."[53] In reviewing the results of its second competitive solicitation, the Hartburg-Sabine Junction project in east Texas, MISO was further encouraged to find that there was a significant improvement in the quality of proposals between the first and second solicitations, stating that "it was clear RFP Respondents that participated in the Duff-Coleman solicitation brought forward meaningful insights and experience they gained in that process."[54] The additional experience of developers can be seen in the results. Whereas only one project scored above 80 (on a 100 scale) in the first solicitation for Duff-Coleman, five proposals did so in MISO's second solicitation for Hartburg-Sabine Junction.

Figure 16 below summarizes the two solicitations that MISO completed. In both cases, MISO received over 10 proposals and selected a developer with estimated construction costs 15% below MISO's initial project cost estimate.

In MISO's detailed reports on its selection processes, MISO highlighted the most noteworthy results of the procurement processes and many of the innovative features proposed by the developers. In the competitive process for the Duff-Coleman project, MISO noted that all of the proposals came in lower than MISO's initial cost estimate and developers provided a range of cost caps, concessions, and commitments, including caps on construction costs. MISO noted that bidders made substantial efforts in preparing their proposals for pre-construction surveys and research and had gone to great lengths to understand the complexity of the regulatory and permitting frameworks, including early consultations with regulatory authorities.

The selected proposal for the Duff-Coleman 345 kV project was awarded to Republic Transmission (an LS Power Subsidiary), which MISO found to have the "highest degree of certainty and specificity, the lowest risk, and low cost."[55] MISO also found the selected project proponent's design to be superior to other proposals while remaining competitive on cost. MISO valued the rigor and specificity throughout the proposal, including a robust documentation of all

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53 MISO, Duff-Coleman EHV 345 kV Competitive Transmission Project, Selection Report, December 20, 2016, p. 2. Available at: https://cdn.misoenergy.org/Duff-Coleman%20EHV%20345kv%20Selection%20Report82339.pdf

54 MISO, Hartburg-Sabine Junction 500 kV Competitive Transmission Project, Selection Report, November 27, 2018, p. 3.

55 MISO, Duff-Coleman EHV 345 kV Competitive Transmission Project, Selection Report, December 20, 2016, p. 3.

implementation "sub-criteria," which reduces the risks of cost and schedule overruns. MISO similarly found the selected developer's O&M plan to be "comprehensive and highly specific."[56]

Figure 16
MISO Competitive Transmission Solicitations

	Duff-Coleman EHV 345 kV Project	Hartburg-Sabine Junction 500 kV Project
Project Scope	One 345 kV line	One 500 kV line, four 230 kV lines, and a 500 kV substation
Project Location	Southern Indiana and Western Kentucky	Eastern Texas
Selection Year	2016	2018
Number of Proposals	11	12
Noteworthy Elements of Proposals	- Caps on implementation costs, ROE, and capital structure - Early regulatory consultations - Pre-construction surveys	- Schedule guarantees - 10 or 40 year ATRR caps, ROE caps - Diverse designs proposed - Significant preliminary fieldwork
Proposal Selected	Republic Transmission, LLC (LS Power Subsidiary)	NextEra Energy Transmission Midwest, LLC
Features of Winning Proposal	- Superior design - Most complete proposal - Robust cost caps - Low O&M costs - Most long-term certainty	- Robust design at low cost - Cost certainty (construction cost cap and 10-year ATRR caps) - Enhanced flexibility - Extensive planning and outreach - Hurricane-related experience
Construction Cost Estimates	MISO = $58.9 million Winning Proposal = $49.8 million Difference = -$9.1 million (-15%)	MISO = $122.4 million Winning Proposal = $103.9 million Difference = -$18.5 million (-15%)

Notes: The cost of the winning proposal for the Hartburg-Sabine Junction 500 kV project is shown above in 2018 dollars to be comparable to the MISO cost estimate. NextEra estimated the project will cost $114.8 million in nominal dollars.
Sources: Duff-Coleman: MISO, Duff-Coleman EHV 345 kV Competitive Transmission Project, Selection Report, December 20, 2016; Hartburg-Sabine Junction: MISO, Hartburg-Sabine Junction 500 kV Competitive Transmission Project, Selection Report, November 27, 2018.

In the competitive process for Hartburg-Sabine Junction, MISO again received a diverse set of proposals, including for structure and conductor types and the 230 kV bus arrangements. MISO found that many of the proposals included well-developed project schedules and plans based on critical path analysis and risk analysis for the projects. MISO noted that several of the proposals went so far as taking soil samples when conducting preliminary fieldwork to assess the risks

56 MISO, Duff-Coleman EHV 345 kV Competitive Transmission Project, Selection Report, December 20, 2016, p. 8.

associated with siting and permitting. In addition, the bids provided schedule guarantees and caps on annual transmission revenues requirements over the first 10 or 40 years.

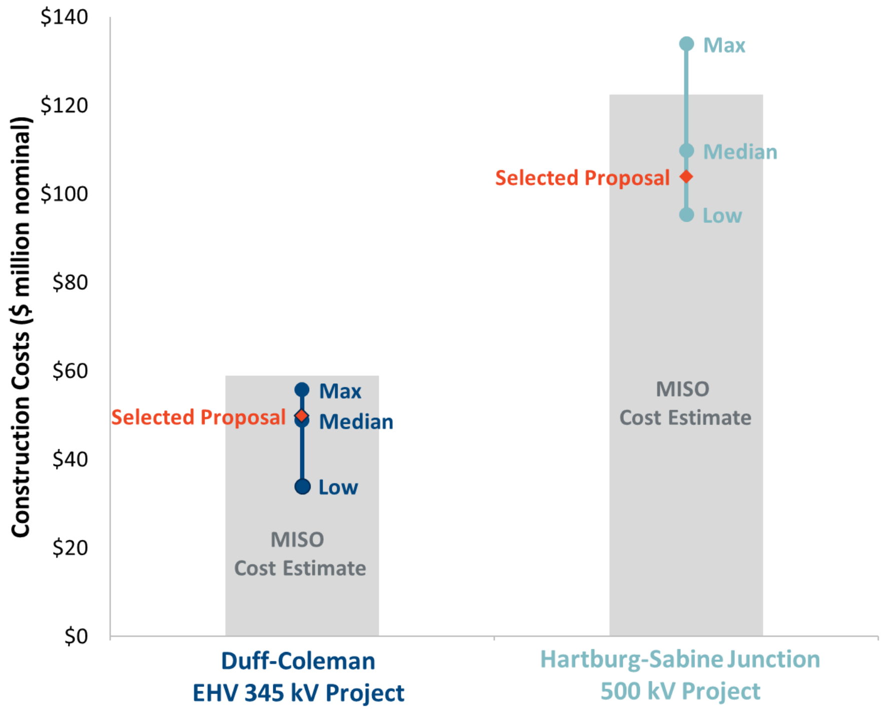
MISO noted that the selected developer for the Hartburg-Sabine Junction project offered "an outstanding combination of low cost and high value, with best-in-class cost and design, best-in-class project implementation plans, and top-tier plans for O&M [with] an estimated benefit-to-cost ratio of 2.20."[57] The selected developer proposed both a schedule guarantee as well as a cap on total construction costs and the revenue requirements over the first 10 years. MISO valued the enhanced operational and planning flexibility provided by the design proposed by NextEra. Prior to submitting the proposal, NextEra had completed extensive outreach to federal, state, and local authorities and included substantial project-specific planning, site analysis, and field investigation in its implementation plan. Finally, MISO noted that the O&M proposal from NextEra included comprehensive procedures for repairing equipment and extensive experience in hurricane-prone areas.

Below, in Figure 17, we show the maximum, minimum, median, and selected proposal's cost estimates for the Duff-Coleman and Hartburg-Sabine Junction projects (as blue and red dots), as well as MISO's own cost estimate (as grey bars). Noticeably, there are large ranges of price estimates for both projects and proposal estimates tend to be less than MISO's own. Additionally, in neither case did MISO select the lowest cost proposal. This demonstrates MISO's thorough consideration of multiple elements of the proposed projects, such as design quality and cost containment mechanisms.

MISO's experience in these two competitive solicitations demonstrates the value of competitive transmission processes; attracting experienced project developers that have brought forward higher quality-proposals at lower cost and with less uncertainty than projects not resulting from competitive solicitations, which will ultimately results in cost savings for end-use customers. Perhaps more important than these project cost saving is the innovation that has occurred over the course of only two competitive solicitations, which promises significant benefits going forward.

57 MISO, Hartburg-Sabine Junction 500 kV Competitive Transmission Project, Selection Report, November 27, 2018, p. 2. The winning project's benefit-to-cost ratio of 2.20 compares to MISO's initial estimate of the project's benefit-to-cost ratio of 1.35.

Figure 17
MISO Competitively-Developed Projects Construction Cost Estimates



Notes: The cost of the winning proposal for the Hartburg-Sabine Junction 500 kV project is shown above in 2018 dollars to be comparable to the MISO cost estimate (also in 2018 dollars). NextEra's proposed cost of $114.8 million (in nominal dollars for the completed project).
Sources: Duff-Coleman: MISO, Duff-Coleman EHV 345 kV Competitive Transmission Project, Selection Report, December 20, 2016; Hartburg-Sabine Junction: MISO, Hartburg-Sabine Junction 500 kV Competitive Transmission Project, Selection Report, November 27, 2018.

VIII. Cost of Administering Competitive Processes

We understand from many developers that there are significant costs associated with preparing the proposal package that one must consider when participating in the competitive processes. Further, the ISO/RTOs spend time and budget preparing for the solicitation, conducting the competitive procurement process, analyzing the received proposals, and reporting on the process and the results. The cost of administering the processes are generally recovered from bidders through fees charged to each developer that submits a proposal, which in turn adds to the costs of the project bids. For the developers that are not selected, those costs are borne by the companies themselves.

For the ISOs/RTOs, SPP reported that the internal costs of completing the competitive process for the North Liberal–Walkemeyer 115 kV project was just above $500,000, requiring the recovery of

$47,000 from each of the eleven respondents of the competitive solicitation.[58] In this case, SPP initially charged a fee of $25,000 per submitted proposal and then billed respondents an additional $22,000 following the end of the process to cover SPP's remaining costs, resulting in no direct costs to SPP's transmission customers. SPP's $500,000 evaluation cost for its first competitive solicitations accounted for approximately 3% of the relatively small project's $17 million cost estimate.[59]

PJM structures its fees for competitive projects based on the proposal cost estimate with no fee for project submissions with project costs of less than $20 million, $5,000 for projects from $20 million to $100 million, and $30,000 for all projects that cost more than $100 million.[60] As of December 2017, the fees PJM collected from developers during the five proposal windows in 2016 and 2017 covered 97% of its $1.7 million of total 2016–2017 evaluation costs.[61] PJM approved a total of 139 projects from these proposal windows, resulting in $44,000 of evaluation costs per approved project.

Additional insights about the magnitude of the costs associated with competitive bidding processes for transmission projects can be gained from the experience in the U.K. The U.K. Office of Gas and Electricity Markets (Ofgem), the regulatory agency, reviewed costs from several rounds of successful bidding for off-shore transmission projects in its 2016 justification to expand competitive processes to new onshore transmission investments.[62] This assessment estimated that

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58 SPP, CTPTF Transmission Owner Selection Process Update, Presented to Strategic Planning Committee, July 7, 2016, p. 33. Available at: https://www.spp.org/documents/39274/spc%20ed%20session%20materials%2020160707.pdf

59 SPP estimated that developers spent $300,000 to $400,000 for each of the 11 proposals submitted to its solicitation for North Liberal – Walkemeyer 115 kV, for a total of $3.3 million to $4.4 million of developer costs. Similar to SPP's costs of administering the competitive solicitation process, these costs are not directly passed through to customers. Prepared Statement of Paul Suskie, Executive Vice President and General Counsel, Southwest Power Pool, Inc., Before the Federal Energy Regulatory Commission, Docket No. AD16-18-000.

60 PJM, Competitive Planning Process Proposal Fee Status Update, December 14, 2017, p. 3. Available at: https://pjm.com/-/media/committees-groups/committees/pc/20171214/20171214-item-06-proposal-fees.ashx

61 PJM, Competitive Planning Process Proposal Fee Status Update, December 14, 2017, p. 4. Available at: https://pjm.com/-/media/committees-groups/committees/pc/20171214/20171214-item-06-proposal-fees.ashx

62 Ofgem, *Extending Competition in Electricity Transmission: Impact Assessment*, May 27, 2016, Sections 3 and 4.7. Available at:

approximately 4% of a large project's total costs are associated with conducting and participating in the competitive bidding process. Of the estimated 4% of total project costs, developers' costs were estimated at approximately 2% of the project cost. The rest of the costs associated with the competitive process is associated with Ofgem's conducting the solicitation at 1%, and the remaining 1% of the process costs were incurred by the network owners and system operator. In comparison, the U.K. experience with offshore transmission shows that three rounds of competitive solicitations for 15 projects achieved estimated savings averaging 23% to 34% of total project costs (as discussed further in Section XII below).

While administrative and developer costs may be significant in the first few rounds of the competitive processes, we expect these costs would decline as experience is gained along the way. We recognize that these costs (including administrative charges) will ultimately need to be recovered by the developers and would thus need to be reflected in the price of their proposal—even if not every developer includes these costs in every bid and every round of competitive solicitation. As a result, these costs will likely be reflected in competitive project cost proposals and thus are already reflected in our estimates of cost savings.

IX. Estimated Cost Savings from Competitive Transmission Processes To Date

As discussed previously, the current experience shows that transmission projects procured through the competitive processes have yielded project offer prices that, on average, were significantly below the projects' initial cost estimates. While 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. Cost escalations are often unavoidable due to factors that include inflation, other uncertainties around materials and labor costs, and scope and routing changes that become necessary during the development process. Because the cost of major regional transmission projects typically escalate beyond initial cost estimates, the extent to which the proposed prices of competitive projects are below initial cost estimates provide us only a first order-of-magnitude estimate of the potential cost savings associated with competitive processes. Considering typical cost escalations and international comparisons allows us to further refine these savings estimates.

https://www.ofgem.gov.uk/system/files/docs/2016/05/extending_competition_in_electricity_transmission_updated_impact_assessment_0.pdf

Our review of the experience with competitive transmission processes to date indicates a significant potential for cost savings. As documented earlier and summarized in Figure 18 (Column 4) below, the selected proposals from the competitive transmission solicitations were priced 15% to 60% (averaging 40%) below either the initial project cost estimates or the lowest-cost incumbent project offer price. In addition, many winning proposals generally have included cost caps or various cost control measures that are expected limit the risks of significant cost escalations.

In regions with solution-based competitive procurement processes, such as NYISO and PJM, competition can foster additional benefits from innovative project design. For example, in the solicitation process for PJM's Artificial Island Project, many developers proposed a wide range of solutions to meet the identified transmission need. Some developers proposed lower-voltage design options that addressed all the needs identified by PJM at reduced cost and constructability risk. In contrast, some of the solutions offered by developers included significantly longer circuit-miles and only 500 kV options at significantly higher costs. In NYISO, the solutions-based competitive process for the New York transmission projects similarly attracted multiple design innovations that yielded lower costs and higher net benefits.

The analysis of historical average cost escalations for major regional transmission projects presented in Appendix A (and summarized in Column 5 of Figure 18 below) shows that completed costs have historically been 18% to 70% (averaging 34%) above initial project cost estimates. These cost escalations relative to initial estimates typically relate to factors such as inflation, routing adjustments, or environmental permitting-related conditions not reflected in the initial estimates. As further discussed below the final costs of 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. However, some cost caps are binding and the cost containment measures of selected proposals will likely limit the cost increases to levels below those experienced by projects historically.

Figure 18
Estimated Range of Potential Savings from U.S. Competitive Transmission Projects to Date

Region [1]	ISO or Incumbent Estimated Cost of Competitive Projects ($million) [2]	Selected Developer's Estimated Cost of Projects ($million) [3]	**Average % Competitive Projects Cost Savings as Proposed* [4]**	Average Historical Escalation of Regional Transmission Projects (%) [5]	Expected Cost if Competitive Projects were not subject to Competition ($million) [6]	Potential $ Savings from Competition w/o bid price escalation ($million) [7]	**Potential % Savings without Cost Escalation of Competitive Projects* [8]**
CAISO	$1,180	$833	**29%**	41%	$1,667	$834	**50%**
ISO-NE	n/a	n/a	n/a	70%	n/a	n/a	n/a
MISO	$181	$154	**15%**	18%	$215	$61	**28%**
NYISO	$232	$181	**22%**	n/a	$232	$51	**22%**
PJM	$692	$280	**60%**	22%	$847	$567	**67%**
SPP	$17	$8	**50%**	18%	$20	$11	**58%**

Note: *The % shown in Column 4 (Average % Competitive Projects Cost Savings as Proposed) reflects an estimate of final cost savings of competitively-developed projects assuming that their cost escalate similar to the historical average cost escalations in each region (see Appendix A for more details). Column 8 reflects an estimate of final savings assuming no escalations of proposed competitive project costs. For CAISO, the percentage differences shown in columns 4 and 5 are both relative to the high end of the CAISO cost estimate. (Using the low end of the CAISO range would reduce the value in column 4 but increase the value in column 5; as a result, the savings shown in column 8 would be unaffected.) For PJM, competitive project values only reflects the Artificial Island project. For NYISO, the estimate is based only on the Western NY Public Policy Transmission project.

Based on our review of the contracts for the competitively-developed projects in which LS Power is involved, the range of cost caps on the potential cost escalations varies project-by-project based on the specific cost-control commitments made in the developers' proposal.

- *Artificial Island Project (PJM)*: LS Power included a construction cost cap of $146 million that covers all LS-Power-related construction costs of the project, including those associated with obtaining permits, acquiring land, and environmental assessments and mitigations. There are exclusions to the cost cap for costs associated with certain specified types of *force majeure*-type events, taxes, financing, and any incremental costs to the project caused by PJM-directed changes to the project. Finally, the cost cap escalates with inflation until the start of construction based on changes in the Handy-Whitman cost index.
- *Harry Allen–Eldorado 500 kV (CAISO)*: LS Power set a cost cap of $147 million in 2020 dollars. There are exclusions to the cost cap for *force majeure* events, financing costs, and cost increases caused by changes from the ISO or from the incumbent transmission owners at their substations.
- *Duff-Coleman 345 kV*: LS Power agreed to a cost cap where the items excluded from the project's Total Rate Base Cap of $58.1 million were costs from *force majeure* events and on-going O&M costs. Deviations from their cost cap are also allowed for material changes to

the scope of the work outside of the RFP that had not been apparent at the time of the proposal.

The experience in Alberta with the Fort McMurray West 500 kV Transmission Project shows that the costs of competitive transmission projects can rise above the proposed cost estimate due to changes in the transmission route and other factors, just as they can for transmission projects not subject to competition. In the Fort McMurray West's case, a change in route increased the allowed costs of the project by 13% from CAD$1.43 billion to CAD$1.61 billion.[63] In contrast, none of the LS Power commitments identified above include an allowed adjustment due to changes in the project route.

If the resulting cost escalation of competitive projects relative to the price of the selected proposal is less than the historical average cost escalations for regional transmission projects (due, for example, to the cost caps or other contractual cost control measures), the savings from the competitive processes will be higher than the range of savings based on just the difference between accepted project offer prices and initial cost estimates. As shown in the last column of Figure 18 above, savings would range from 22% to 67% if all competitive projects awarded to date could be completed at the proposed cost and not face escalations similar to other regional transmission projects. The more likely outcome, however, is that the savings would fall within the range defined by columns 4 and 8 of Figure 18. Completed costs of competitively-developed projects likely will be above their bid price but on average may not escalate as much as other regional transmission projects have historically due to the additional due diligence conducted by bidders before the competitive process and the cost caps and cost control commitments resulting from the competitive processes. Only if the cost of competitive projects were to escalate by *more* than the average historical transmission projects, would the overall savings be less than the range defined by columns 4 and 8 of Figure 18. This is unlikely because transmission developers with cost commitments have significant incentives to minimize the impact of project changes and cost escalations compared to those without similar cost control mechanisms.

Figure 19 below summarizes the ranges of estimated cost savings based on the experience with competitively-developed transmission projects in the U.S. and abroad. The ranges for the U.S. are generally consistent with the estimated cost savings from competitive transmission development

[63] See Fort McMurray West 500 kV Transmission Project, available here: https://www.aeso.ca/grid/competitive-process/fort-mcmurray-west-500-kv-transmission-project/ and See AUC Decision 21030-D02-2017, p. 122, available here: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2017/21030-D02-2017.pdf

abroad—21% savings in Alberta, 16% in Ontario, 23% to 34% in the U.K., and 25% in Brazil. Based on these ranges and international comparisons we believe competitive transmission development processes can be expected to yield cost savings averaging between 20% and 30%.

Figure 19
Range of Savings from Individual Competitively-Bid Transmission Projects to Date

Region	Estimated Cost Savings	No. of Projects Evaluated	Estimated Cost of Project(s)	Notes
CAISO	29–50%	9	$833 million	Selected proposal costs compared to CAISO initial cost estimate; assuming a range of cost escalation for the selected bid of between zero to the level of historical average cost escalation of transmission projects in CAISO (+41%)
MISO	15–28%	2	$154 million	Selected proposal costs compared to MISO's initial cost estimate; assuming a range of cost escalation for the selected bid of between zero to the historical average cost escalation of transmission projects in MISO (+18%)
PJM	60–67%	1	$280 million	Selected proposal cost (including necessary incumbent upgrades) compared to the lowest-cost solution offered by incumbent in the initial proposal window; assuming a range of cost escalation of between zero to the historical average cost escalation of transmission projects in PJM (+22%)
NYISO	22%	1	$181 million	Selected proposal cost compared to lowest-cost bid from incumbent
IESO	16%	1	CAD 777 million	Selected proposal cost compared to bid from incumbent
AESO	21%	1	CAD 1,614 million	Selected proposal cost compared to AESO initial cost estimate; costs of the winning bid later increased due to changes in route
U.K.	23–34%	15	~£3,000 million	Selected bid cost estimate compared to merchant and regulated counterfactuals estimated by Ofgem
Brazil	~25% (20–40%)	Many	$28 billion	Based on Brazil's experience since 1999 holding auctions for all projects over 230 kV; over 50,000 km of lines built through this process

Source: See Appendix C, Table 24 ("Estimated Savings Across All Regions").
Excludes SPP due to the cancellation of its only competitive project.

The above estimates of cost savings for U.S. competitively-developed transmission projects awarded since 2013 rely on assumptions about possible cost escalations from the proposed cost of the selected bids until they will be completed. The resulting range of estimated U.S. cost savings, however, is consistent with the cost savings realized by the only completed competitively-developed U.S. transmission project—the "Path 15 Upgrade" project consisting of a new 500kV transmission line across the historically heavily congested Path 15 corridor as briefly summarized below.

The **Path 15 Upgrade** project, completed in 2004 and initiated prior to the time period studied in this report, was the first independent, project-financed, greenfield transmission development in the U.S. The developer, TransElect, benefitted from a streamlined permitting process through a public-private partnership with Western Area Power Association (WAPA) that allowed the development team to secure rights of way at lower cost than under traditional utility ownership. The development team structured and competitively procured an innovative fixed-price Engineer-Procure-Construct (EPC) contract that left key decisions about project design and execution to the EPC contractors, thereby providing strong incentives for cost reductions through innovative project design and construction management. This structure combined the selection of qualified contractors with strong incentives for on-time completion of the project. The end result was that the Path 15 Upgrade was completed on time and under budget at a cost of approximately $250 million and well below the $306 million cost initially estimated by PG&E (the incumbent transmission owner) during the planning phase.[64] Even under the assumption that a traditionally-developed Path 15 project could have been constructed at PG&E's initial estimate without any further cost escalation, the realized cost savings were $56 million or 18%. Recognizing that the completed costs of a traditionally-developed Path 15 Upgrade may have been above PG&E's initial cost estimate, the actually-realized construction-related cost savings are even higher than that.

X. Potential Benefits from Expanding Competitive Transmission Processes in the U.S.

The significant cost savings offered by the relatively small number of competitive transmission solicitations to date raise the question how high potential cost savings could be if the scope of competition could be expanded. As mentioned above, the scope of competitive processes has been limited to only 3% of total transmission investments over the last five years. While FERC Order 1000 acknowledged that certain types of projects can be excluded from the competitive processes and FERC has allowed transmission owners to maintain their federal rights of first refusal for upgrades to existing facilities, one of the primary goals of Order 1000 was to advance *cost-efficient development of transmission*. To that end, FERC had identified greater engagement of non-incumbent transmission developers as a means to increase the cost-effectiveness of the nation's transmission infrastructure investments. Given that some ISO/RTOs have successfully implemented a broader-scope of competitive engagement by excluding fewer transmission project

[64] Prepared Direct Testimony of Johannes P. Pfeifenberger, FERC Docket Nos. ER14-1332-000, Exhibit No. DAT-8, February 18, 2014, page 38.

types than other regions—and given that there are opportunities for state policymakers to explore changes to or elimination of various existing state laws that impede competition for transmission projects—it is clear that the scope of competition could be expanded substantially.

Having a larger share of transmission investments developed through competitive processes would yield significant customer savings. Based on the experience with competitively-developed transmission in the U.S. and abroad, competitive processes are more likely to be adopted for higher voltage and higher cost projects. Figure 20 below shows that of all RTO-planned transmission investment in PJM and MISO (excluding locally-planned transmission, which includes most upgrades to existing facilities), about half of all MISO projects and 77% of PJM projects cost more than $25 million. Based on voltage, about half of the investments planned by MISO and PJM have involved voltage levels above 300kV and about 66% have been above 150kV.

Figure 20
PJM and MISO Transmission Costs by Total Project Cost and Voltage

	PJM		MISO	
	Costs *$ million*	**Percentage** *% of Total*	**Costs** *$ million*	**Percentage** *% of Total*
Project Costs				
<$25 million	$836	23%	$2,708	48%
$25-50 million	$836	23%	$389	7%
$50-100 million	$1,032	28%	$706	13%
>$100 million	$991	27%	$1,794	32%
Project Voltage				
Up to 138 kV	$994	27%	$1,608	33%
138 - 300 kV	$976	26%	$456	9%
>300 kV	$1,725	47%	$2,870	58%

Sources: 2014–2017 PJM TEAC Staff Whitepapers, PJM Transmission Construction Status Database, and MISO's MTEP Appendix A Status Trackers.

Based on these statistics, we believe the scope of competition could reasonably be expanded from one quarter to one third of total transmission investments. This level of competitively-developed transmission should be achievable, particularly if the current barriers to the development of cost-effective regional and interregional transmission projects to address market efficiency and public policy needs can be reduced. As previously shown in Figure 4, if competition reduced transmission costs by 25% on average, applying these cost savings from competition to one-third of planned U.S. transmission investments would reduce customer costs by approximately $8 billion over the course of five years.

We recognize that long-term cost advantages of competitively-developed transmission projects will likely decline as the innovations and cost-reductions stimulated by competitive processes define best practices that are increasingly applied to a broader set of transmission projects. Customer benefits will be even greater, however, if the innovations and cost-control mechanisms developed through competitive processes can be transferred and applied to the development of transmission projects not subject to competition.

In summary, the current experience with competitive transmission development processes provides a compelling demonstration that competition can create customer benefits consistent with the goals of FERC Order 1000—particularly if a greater proportion of future transmission investments could be developed competitively. One of the most important takeaways from this experience is that reducing the current restrictions imposed on competitive transmission processes is important if meaningful customer savings should be achieved. At minimum, encouraging more competitive transmission development will yield innovation and increased cost discipline on the industry and thereby benefit electricity users. Competitive processes also provide opportunities for all participants to propose and implement contractual mechanisms—such as binding construction cost caps—that would not otherwise be available. As these competitive processes become more widespread and transparent, they will lead all developers to apply more innovative project development and cost controls. The resulting more cost effective transmission development will also benefit transmission owners by reducing rate pressures and by magnifying the benefits and attractiveness of transmission solutions that increasingly compete with local generation alternatives and the declining costs of renewable generation and storage technologies, thereby increasing the total amount of cost-effective transmission investments.

XI. Competitive Transmission Processes in Non-ISO/RTO Regions

FERC Order 1000 applies to regional planning entities in non-ISO/RTO areas in the southeastern and western part of the U.S. These non-ISO/RTO regional planning entities include Southeastern Regional Transmission Planning (SERTP), the South Carolina Regional Transmission Planning (SCRTP), and Florida Reliability Coordinating Council (FRCC) in the southeast; and ColumbiaGrid, Northern Tier Transmission Group (NTTG), and WestConnect in the west. They have developed planning processes to comply with Order 1000 based on a more limited scope of benefits than are considered in most ISO/RTO-administered regional planning processes.[65] The

[65] Chang, *et al.*, The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments, July 2013, p. 32.

most common benefit considered in these non-ISO/RTO regions is the ability of a regional project to displace higher-cost local transmission projects that are included in the base regional system plan, which are often referred to as “cost effective or efficient regional transmission solutions” (CEERTS).

We are not aware of any competitive transmission projects moving forward in any of the non-ISO/RTO regions. The limited scope for competitive projects in these regions likely relates to very restrictive qualification criteria. For example, SERTP substantially limits the scope of projects that can qualify for regional cost allocation and considers a limited set of benefits of those projects. To qualify for regional cost allocation in SERTP, new transmission projects must be 300 kV or greater and at least 50 miles long.[66] Since the region does not currently operate 345 kV transmission facilities, the requirement limits regional projects solely to 500 kV facilities. Similar to other non-ISO/RTO regions, SERTP considers only two project benefits: displacing or deferring projects included in the regional system plan and reducing energy losses. The limited scope of projects that can qualify, the limited benefits considered, and a high benefit-to-cost ratio have resulted in no regional projects being considered in SERTP’s planning process. In fact, no transmission developers have pre-qualified to submit regional projects in each of the SERTP planning cycles since 2015.[67]

The other non-ISO/RTO planning regions similarly had limited success in attracting and approving competitively–developed transmission lines:

- WestConnect analyzed nine non-incumbent projects in its 2016–17 planning process, but did not identify any projects that warranted inclusion in the Base Transmission Plan.[68] In addition, WestConnect did not identify any reliability, economic, or public policy needs in the 2016–17 study and therefore did not consider the projects for regional cot allocation.[69]

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66 SERTP, PJM-SERTP: Order 1000 Biennial Regional Transmission Plan Review Meeting, April 26, 2016, p. 14.

67 For example, see http://southeasternrtp.com/docs/general/2018/2018-October-Pre-qualified-Transmission-Developers-for-the-Upcoming-2019-Planning-Cycle.pdf

68 WestConnect, Regional Study Plan, WestConnect Regional Transmission 2016–17 Planning Cycle, March 16, 2016, p. 39. Available at: https://doc.westconnect.com/Documents.aspx?NID=17180&dl=1

69 WestConnect, Regional Transmission Plan, WestConnect Regional Transmission Planning 2016–17 Cycle, December 20, 2017, p. 39. Available at: https://doc.westconnect.com/Documents.aspx?NID=18010&dl=1

The draft 18/19 Regional Needs Assessment similarly found no regional transmission needs.[70]

- NTTG analyzed six projects in its 2014–2015 regional planning process and identified two regional projects to be more efficient or cost-effective than local projects in the Initial Regional Plan.[71] However, one did not qualify for cost allocation and the other did not request regional cost allocation, which excluded them from the competitive process. No projects were submitted for consideration in the 2016–2017 planning process.[72]
- ColumbiaGrid allows stakeholders to submit suggestions for potential needs during its biennial transmission expansion planning study. In the 2017 study, a stakeholder identified the California 50% RPS as a public policy need. However ColumbiaGrid found that none of its entities must comply with this policy and thus there was no need identified.[73] In the 2019 study, no needs were suggested.[74] As a result, no alternative regional projects were analyzed in either study.
- FRCC has conducted two solicitation windows for competitive proposals and received three proposed regional alternatives to local projects. However, it was subsequently determined that there was no longer a need for the local projects, which means the solicitations did not result in the approval of a competitive project.[75]

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70 WestConnect, 2018–2019 Regional Planning Cycle, http://regplanning.westconnect.com/2018_19_regional_plng_cycle.htm, accessed March 21, 2019.

71 NTTG, 2014–2015 Regional Transmission Plan, December 30, 2015, p. 3. Available at: https://nttg.biz/site/index.php?option=com_docman&view=download&alias=2595-nttg-2014-2015-regional-transmission-plan-final-12-30-2015&category_slug=2014-2015-regional-transmission-plan-final&Itemid=31.

72 NTTG, 2016–2017 Regional Transmission Plan, December 28, 2017, p. 11. Available at: https://www.nttg.biz/site/index.php?option=com_docman&view=download&alias=2948-nttg-2016-2017-regional-transmission-plan-final-12-28-2017&category_slug=2016-2017-regional-transmission-plan-final&Itemid=31

73 ColumbiaGrid, 2017 Biennial Transmission Expansion Plan, pp. 14–15. Available at: https://www.columbiagrid.org/download.cfm?DVID=4912

74 ColumbiaGrid, 2019 Biennial Transmission Expansion Plan, p. 19. Available at: https://www.columbiagrid.org/client/pdfs/2019%20Biennial%20Transmission%20Expansion%20Plan%20(BTEP).pdf

75 For example, see FRCC Biennial Transmission Planning Process (BTPP): Step 3&4, February 25, 2016, p. 5.

- SCRTP has set similar limits on competitive regional projects as SERTP, including that the project must be above 230 kV, longer than 50 miles, cost more than $10 million, and be developed as a greenfield facility.[76] SCRTP has received no proposals for alternative projects to date.

XII. International Experience with Competitive Transmission Processes

The use of competitive transmission processes has not been limited to the U.S. They have been utilized in other countries, including Canada, the U.K., Brazil, Chile, and Australia.

In **Canada**, three competitive transmission solicitations have been completed; one in Alberta and two in Ontario. In both provinces, the price of the winning bids were significantly lower than ISO planning cost estimates or incumbent cost estimates, but in both cases the projects faced cost escalations. In Alberta, cost estimates for the Fort McMurray West 500 kV Transmission Project were originally estimated to be CAD $1.43 billion, 21% lower than the initial AESO estimate of CAD $1.8 billion. Due to a change in project routing (which would have increased the AESO's estimate), the final costs for the project increased to CAD $1.61 billion.[77] The AESO notes that the competitive bidding of the project, which was energized in March 2019 on budget and three months ahead of schedule,[78] provided Alberta ratepayers over $400 million in savings.[79] Similarly, the costs of Ontario's East-West Tie Line project increased from 2020 CAD $439 million to 2020 CAD $777 million, which still falls 16% below the incumbent transmission owner's (Hydro One's) estimate for a comparable line. This range of savings from competitive transmission in Alberta

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76 SCRTP, Transmission Planning Process (Attachment K), Section VII. Regional Transmission Planning, October 15, 2013, p. 288. Available at: https://www.scrtp.com/document-library

77 See Fort McMurray West 500 kV Transmission Project, available here: https://www.aeso.ca/grid/competitive-process/fort-mcmurray-west-500-kv-transmission-project/ See also AUC Decision 21030-D02-2017, p. 122, available here: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2017/21030-D02-2017.pdf

78 See "Alberta PowerLine places 500-kV transmission line into service," March 29, 2019. Available at : https://ml.globenewswire.com/Resource/Download/9eb84e58-d533-4b74-bffb-4e2340bbf6da

79 The AESO also notes that the winning bid included all project costs while the AESO's initial estimate included only construction costs, estimating that "competition cost savings for Alberta ratepayers is conservatively estimated to be over $400 million." See: https://www.aeso.ca/grid/competitive-process/fort-mcmurray-west-500-kv-transmission-project/

(21%) and Ontario (16%) is within the range of estimated savings achieved by the competitive solicitations in the U.S.

In **the U.K.**, competitive solicitations have been conducted for offshore transmission by the Office of Gas and Electricity Markets (Ofgem, the national regulator) since 2009. Through three separate Offshore Transmission Owner ("OFTO") Tender Rounds, investors competed to own, finance, and operate transmission assets of about £3,000 million.[80] OFTO Rounds 1, 2, and 3 had estimated savings ranging from £683 million to £1,092 million.[81] The positive experience with competition in offshore transmission—accounting for estimated cost reductions averaging 23%–34% (net of the cost of conducting the process) compared to regulated counterfactuals with an estimated range of 14% to 45% for the individual rounds—has led Ofgem to complete three additional rounds for offshore wind and expand the scope of competitive solicitations to include all large new onshore transmission investments as well.[82]

In **Brazil**, competitive transmission auctions have been conducted by ANEEL, the Brazilian Electricity Regulatory Agency, since 1999 to select who builds, operates, and owns transmission assets.[83] These auctions operate by offering maximum annual revenue requirements (estimated based on typical project costs) and having bidders propose lower revenue requirements, with the

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80 The Ofgem offshore transmission policy design is available here: https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission/offshore-transmission-policy-design

Total value of competitively-developed projects estimated based on reported savings.

81 Ofgem, *Evaluation of OFO Tender Round 2 and 3 Benefits*, March 2016, available here: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

82 For an update on competition in U.K. onshore electricity transmission see: https://www.ofgem.gov.uk/publications-and-updates/update-competition-onshore-electricity-transmission

For a summary of off-shore experience and justification for introducing competition to the onshore network, see: https://www.ofgem.gov.uk/system/files/docs/2016/05/extending_competition_in_electricity_transmission_updated_impact_assessment_0.pdf

83 For a summary of Brazil's experience with competitive transmission see: Chang and Pfeifenberger (2015), Competitively-Bid Transmission Investments in the U.S. and Abroad, August 4, 2015, pp. 14–15.

See also Ofgem (2013), *Integrated Transmission Planning and Regulation Project: Review of System Planning and Delivery,* Prepared for Ofgem, June 2013, Appendix C3, Available at: https://www.ofgem.gov.uk/ofgem-publications/52727/imperialcambridgeitprreport.pdf lowest-cost bid selected as the winner. Between 1999 and 2008, 87 transmission concessions were auctioned, receiving a total of 399 bids by 112 companies and consortiums, 57% of which were foreign bidders.[84] The first 15 years of auctions saw 50,000 km of new transmission built through this competitive process, with a total investment of $28 billion. The total maximum annual revenue requirement on this investment would have been $4.45 billion, which the ANEEL auctions reduced to $3.35 billion, an average 25% cost reduction,[85] with ranges from 20% to 40% for individual projects and individual bids offering cost reductions as high as 58%.[86] The experience in Brazil further showed that the size of the cost reduction is positively correlated with the number of bidders, illustrating that more competition creates stronger downward pressure on costs.[87]

In addition to these experiences, competitive transmission development processes have been utilized in Chile and Australia.[88] In Australia, the state of Victoria has introduced "contestability" for generation interconnections to the transmission grid.[89]

Despite diverse international experiences with competitive transmission and large variety of competitive mechanism, the effects of competitive transmission are clear: more innovation and more cost-effective transmission.

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84 Ofgen (2013) Appendix C3.

85 See Chang and Pfeifenberger (2015) and Ofgem (2013), Appendix C3.

86 Ofgem (2013), Appendix C3, p. 69.

87 *Id.*

88 For a summary of the experience with competitive processes in Chile, see: Ofgem (2013), Appendix C4, p. 72.

89 For example, see Allens-Linklaters, *A new Framework for Transmission Network Connections*, July 30, 2018. Available at: https://www.allens.com.au/pubs/ener/cuener30jul18.htm

See also Freedman, *Transmission Connection Contestability: It's Finally Here, June 5, 2017*. Available at: https://www.linkedin.com/pulse/transmission-connection-contestability-its-finally-here-freedman/

Appendix A: Average Historical Cost Escalations of Transmission Projects Relative to Initial Cost Estimates

To better understand the potential savings offered by competitive processes, we gathered data to analyze the extent to which transmission projects experience cost escalations relative to initial cost estimates. To do so, we reviewed available transmission project cost reports to document deviations between a project's initial cost estimates and its final costs (as reported at the time a project is placed in-service).

In this analysis, we identified the respective projects' initial cost estimates as documented in various project cost tracking reports and other databases made available by CAISO, SPP, MISO, and PJM. With the exception of CAISO, which prepares initial project cost estimates for all CAISO-planned projects, the available initial estimates of project costs in SPP, MISO, and PJM are prepared by the sponsoring incumbent transmission owners. We compare these initial cost estimates to the final project costs as reported by SPP, MISO, and PJM and as recently filed by CAISO transmission owners at FERC in response to the CPUC complaint (as noted earlier).[90]

The historical cost escalations we observed for transmission projects are summarized below in Figure 21 through Figure 25 for MISO, SPP, CAISO, PJM, and ISO-NE. While there are examples of project cost estimates that closely matched realized project costs and some transmission developers likely prepare more accurate estimates than others, there have been large cost escalations for some of these transmission projects. These cost escalations may be driven be inflation during the multi-year project development process and added costs to comply with conditions imposed during the permitting and siting process. On average, these cost escalations ranged from 18% average cost escalations for the reported project types in MISO and SPP to 41% in CAISO and 70% in ISO-NE. The high average cost escalation in ISO-NE is due primarily to the cost escalations on three major projects—the Southwest Connecticut, Greater Springfield, and the

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90 Relying on the transmission owners' own initial project cost estimates may result in a more conservative estimate of cost escalation rates (if any) when compared to competitive project cost savings, given that these initial estimates may not be prepared like ISO/RTO cost estimates. Rather, initial project costs may have been estimated to include additional contingencies to hedge against cost escalations.

Rhode Island Reliability Projects—each of which was completed at more than twice the initial cost estimate.[91]

We recognize that a portion of the observed escalations reflect inflation and justified design changes between the point in time when the initial estimates were made and the time when the projects were placed into service. We also recognize that several of the ISOs/RTOs have recently implemented cost estimation standards and project cost tracking mechanisms intended to improve transparency and the quality of the cost estimates.[92] In fact, where publicly available, these cost tracking mechanisms allowed us to assemble the data analyzed in this report. We use the documented "typical" cost escalations simply to provide reference levels against which to compare the proposed and estimated realized costs of competitively-developed projects. Since the competitively-developed projects may experience cost escalations as well, we present how the costs of both types of transmission projects compare to their initial cost estimates.

The absence of cost-tracking mechanisms in some of the ISO/RTOs, such as CAISO and NYISO, makes it very challenging to observe, document, and monitor project cost changes as projects progress through the development phases. In CAISO, the data filed by the major transmission owners in two FERC complaints shows that the cost escalations relative to CAISO's initial cost estimates are high—with final project costs averaging 41% higher than the upper end of the *CAISO's initial estimates* as summarized in Figure 23 below.[93] We were not able to collect or analyze such data for NYISO.

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91 NextEra Energy Transmission (NEET), *Greater Boston Cost Comparison*, Presented to ISO-NE Planning Advisory Committee, 02/03/2015, p. 5. Accessed at https://www.iso-ne.com/static-assets/documents/2015/02/a2_nht_greater_boston_cost_analysis_public.pdf

92 See, for example, Pfeifenberger and Hou, *Summary of Transmission Project Cost Control Mechanisms in Selected U.S. Power Markets*, October 2011. Available at: https://brattlefiles.blob.core.windows.net/files/6222_summary_of_transmission_project_cost_control_mechanisms_in_selected_us_power_markets_pfeifenberger_hou_oct_2011.pdf

93 FERC Docket Nos. ER16-2320 and ER17-45.

Figure 21
MISO Historical Cost Escalation for Base Reliability, Multi-Value, and Market Efficient Projects (2015–2017 in-Service, 2018 in-Service or Under-Construction)

Year	Number of Facilities	TO Estimate Provided to MISO After Approval ($million)	TO Latest Cost Estimate Provided to MISO ($million)	Cost Escalation %
2015	55	$1,711	$1,672	−2%
2016	110	$1,251	$1,542	23%
2017	62	$780	$822	5%
2018Q1	77	$2,217	$3,017	36%
Total	**304**	**$5,960**	**$7,053**	**18%**

Notes: Cost estimates shown are for in-service & under construction Base Reliability, MVP, and MEP facilities, as reported in MISO's MTEP Appendix A Status Trackers. Cost Change equals TO Latest Cost Estimate Provided to MISO over TO Estimate Provided to MISO After Approval minus 1.

Figure 22
SPP Historical Cost Escalation for Completed Transmission Projects

SPP Portfolio	Initial TO Cost Estimate ($million)	Latest Cost Estimate Tracked by SPP ($million)	Cost Escalation %
Balanced Portfolio	$691	$831	20%
Priority Projects	$1,145	$1,349	18%
ITP Portfolio Projects with Final Cost Estimates (2012 to 2017)	$192	$211	10%
Total	**$2,028**	**$2,391**	18%

Notes: Balanced Portfolio data comes from the 2017 Q2 SPP Quarterly Project Tracking Report.
Priority Projects data comes from the 2017 Q4 SPP Quarterly Project Tracking Report.
ITP Portfolio data comes from the 2019 Q1 SPP Quarterly Project Tracking Report, Appendix 1.

Figure 23
CAISO Historical Cost Escalation for Completed Transmission Projects

Project	TO Cost Estimate submitted to CAISO/CPUC ($million)	CAISO Estimate ($million)	Estimated Final Cost ($million)	Estimated Final Cost relative to TO's CAISO/CPUC Submitted Cost (% change)	Estimated Final Cost relative to CAISO Estimate (% change)
Wheeler Ridge Junction 230kV Substation	$155	$140	$151	−3%	8%
Spring 230kV Substation	$48	$45	$98	104%	118%
Estrella 230kV Substation	$34	$45	$96	179%	113%
Martin 230kV Bus Extension	$129	$129	$285	121%	121%
Midway-Andrew 230kV Project	$154	$150	$198	29%	32%
Lockeford-Lodi Area 230kV Development	$103	$105	$163	58%	55%
Oro Loma 70kV Reinforcement	$46	$46	$30	−34%	−34%
ECO Substation	$273	–	$410	50%	–
New TL ES-Ash #2	$22	< $50M	$5	−78%	–
IV West Generator Interconnection	$2	–	$1	−47%	–
Talega-Add Synchronous Condensers	$64	$72	$81	26%	12%
Shunt Reactor on Suncrest 500kV Bus	$11	–	$10	−10%	–
Pio Pico Energy Ctr. Gen. Interconnect	$9	–	$10	2%	–
Relocate South Bay Substation	$129	$129	$121	−7%	−6%
Talega Bank 50 Replacement	$6	$6	$2	−61%	−64%
TL13821 and TL13828-Fanita Junction Enhancement	$41	<50M	$35	−15%	–
Encina Bank 61	$11	<50M	$8	−29%	–
Tehachapi	$1,800	–	$2,350	31%	–
Total	$3,037	$867	$4,053	**33%**	**41%***

Notes: These Projects are not the complete universe of CAISO projects.
* Percentages exclude projects with no specific CAISO estimates. Estimated Final Cost relative to its CAISO/CPUC Submitted Cost (% change) equals Estimated Final Cost ($million) divided by Cost Estimate submitted by TO CAISO/CPUC minus 1. Estimated Final Cost relative to CAISO Estimate equals Estimated Final Cost ($million) divided by Upper End of CAISO Estimate ($million) minus 1. CAISO typically reports a high and low cost estimate for transmission projects. This table reports CAISO's high estimate as it is generally more consistent with the TO-prepared estimates as submitted to the CPUC as shown above. Measuring cost escalations relative to the CAISO's low estimate would yield higher percentage increases.
Source: Exhibit PUC-0015 in FERC Docket No. ER16-2320-000; SDG&E Responses to data requests issued in FERC No. EL17-45; 2016–2017 CAISO Draft Transmission Plan Stakeholder Meeting; and SCE's 2016 Q4 Quarterly Report.

Figure 24
PJM Historical Cost Escalation for Baseline and Network Projects
(2014–2017 in-Service or Under-Construction Baseline & Network Upgrade Projects)

Year	Initial TO Cost Estimate *(provided at time of PJM Advisory Committee recommendation)* ($million)	Latest TO Cost Estimate *(reported by PJM Cost Allocation Tracking)* ($ million)	Cost Escalation %
2014	$822	$971	18%
2015	$1,722	$2,124	23%
2016	$768	$940	22%
2017	$382	$485	27%
Total	**$3,695**	**$4,520**	**22%**

Notes: Table reflects only projects with reported initial cost data and latest cost data. Cost Escalation equals Latest TO Cost Estimate over Initial TO Cost Estimate minus 1. Projects are categorized into years based on PJM provided "DisplayServiceDate" variable in PJM Transmission Construction Status Database. Supplemental and TO Initiated projects are only notified to TEAC but standard reporting of costs are not tracked by PJM's Transmission Construction Status Database, so they are not reflected in this data.
Source: Initial cost estimates from 2014–2017 PJM TEAC Staff Whitepapers Latest Cost Estimates from PJM Transmission Construction Status Database

Figure 25
ISO-NE Historical Cost Escalations for Major Transmission Projects

Project	Initial TO Cost Estimate ($million)	Final TO Cost Estimate ($million)	Cost Escalation %
Scobie-Tewksbury	$123	$120	−2%
Wakefield-Woburn	$107	$137	28%
Mystic Woburn	$75	$82	9%
Stoughton Cable Project (Phase I & II)	$213	$317	49%
Southwest Connecticut	$690	$1,415	105%
Norwalk Reliability	$128	$234	83%
Worcester Reliability	$7	$33	377%
Long Term Lower SEMA	$107	$105	−2%
Millstone DCT elimination	$22	$39	76%
NEEWS–Greater Springfield	$350	$759	117%
NEEWS–Rhode Island Reliability	$150	$315	110%
Merrimack Valley/North Shore Project	$43	$62	45%
NEEWS–Interstate Reliability	$400	$542	35%
Stamford Reliability	$49	$42	−15%
Total	**$2,464**	**$4,201**	**70%**

Notes & Sources:
Cost information on Scobie-Tewksbury, Wakefield-Woburn, and Mystic Woburn based on ISO-NE Regional System Plan (RSP) Pool Transmission Facility estimate cost, sourced from ISO-NE Final RSP 18 Project List–March 2018, accessed at https://www.iso-ne.com/system-planning/system-plans-studies/rsp/.
Cost information shown for rest of the projects based on: NextEra Energy Transmission (NEET), Greater Boston Cost Comparison, Presented to ISO-NE Planning Advisory Committee, 02/03/2015. Accessed at https://www.iso-ne.com/static-assets/documents/2015/02/a2_nht_greater_boston_cost_analysis_public.pdf.

Appendix B: List of Acronyms

AC	Alternating Current
AESO	Alberta Electric System Operator
BGE	Baltimore Gas and Electric
CAD	Canadian Dollars
CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zone (Texas, ERCOT)
DCR	Delaney-Colorado River (CAISO)
DOE	Department of Energy
EEI	Edison Electric Institute
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Regulatory Energy Commission
IESO	Independent Electricity System Operator (Ontario)
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
ITP	Integrated Transmission Plan (SPP)
kV	Kilovolt
MEP	Market Efficiency Project (MISO)
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Project (MISO)
NEET	NextEra Energy Transmission
NTC	Notification to Construct (SPP)
NYISO	New York Independent System Operator
PG&E	Pacific Gas & Electric
PJM	PJM Interconnection
PSEG	Public Service Enterprise Group
PUC	Public Utility Commission
PUCT	Public Utility Commission of Texas
RSP	Regional System Plan (ISO-NE)
RTO	Regional Transmission Organization
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SPP	Southwest Power Pool
TEAC	Transmission Expansion Advisory Committee (PJM)
TO	Transmission Owner
TPIT	Transmission Project and Information Tracking (ERCOT)
WECC	Western Electricity Coordinating Council

Appendix C: Detailed Data Tables

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6	Competitively-Developed Projects in FERC-Jurisdictional Regions and Selection Year	Table 2
7	Competitive Transmission Qualification Processes of U.S. ISOs/RTOs	Table 4
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Table 1: U.S. Annual Transmission Investments Reported in FERC Form 1 ($million)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2013-2017 Total	1999-2017 CAGR
CAISO	$184	$226	$176	$157	$334	$333	$304	$293	$398	$710	$645	$678	$1,003	$827	$621	$1,635	$1,683	$936	$3,488	$3,185	$2,647	$2,513	$2,422	$1,824	**$12,591**	**10%**
ISO-NE	$143	$91	$100	$111	$83	$92	$127	$167	$171	$203	$203	$309	$705	$785	$2,118	$651	$652	$604	$1,434	$1,769	$1,375	$1,696	$1,420	$1,228	**$7,488**	**15%**
MISO	$418	$332	$383	$421	$351	$338	$333	$1,255	$457	$532	$620	$928	$1,235	$1,233	$1,169	$1,470	$1,421	$1,049	$1,324	$2,476	$2,685	$3,002	$4,023	$3,345	**$15,530**	**14%**
NYISO	$99	$120	$96	$94	$85	$86	$113	$147	$114	$76	$171	$239	$326	$375	$460	$241	$522	$678	$327	$441	$492	$469	$543	$647	**$2,592**	**12%**
PJM	$502	$601	$537	$399	$349	$464	$597	$420	$330	$452	$409	$583	$1,179	$824	$1,278	$1,469	$1,854	$3,405	$2,900	$4,080	$6,602	$7,265	$7,088	$6,433	**$31,469**	**16%**
SPP	$140	$151	$143	$115	$72	$113	$169	$222	$210	$173	$185	$199	$231	$305	$502	$434	$825	$602	$1,165	$961	$2,094	$896	$1,362	$889	**$6,202**	**12%**
Subtotal FERC-jurisdictional RTO/ISOs	$1,486	$1,522	$1,435	$1,298	$1,275	$1,426	$1,642	$2,505	$1,680	$2,146	$2,233	$2,936	$4,680	$4,349	$6,147	$5,901	$6,957	$7,273	$10,637	$12,912	$15,895	$15,841	$16,858	$14,366	**$75,873**	**14%**
ERCOT	$185	$121	$53	$103	$99	$138	$146	$432	$417	$328	$327	$358	$533	$575	$530	$455	$840	$1,171	$1,017	$5,283	$865	$923	$2,000	$1,143	**$10,213**	**12%**
Subtotal U.S. ISO/RTOs	$1,672	$1,643	$1,488	$1,401	$1,374	$1,563	$1,788	$2,937	$2,097	$2,473	$2,560	$3,294	$5,213	$4,924	$6,677	$6,356	$7,797	$8,444	$11,654	$18,195	$16,760	$16,764	$18,858	$15,509	**$86,086**	**14%**
Other WECC	$316	$256	$247	$191	$406	$315	$213	$410	$327	$548	$572	$374	$469	$753	$736	$858	$1,695	$713	$815	$1,169	$758	$1,318	$1,038	$923	**$5,208**	**6%**
Southeast & Other	$536	$565	$580	$359	$351	$429	$616	$869	$890	$922	$979	$896	$1,331	$1,136	$1,383	$1,508	$1,335	$1,826	$1,819	$1,647	$1,631	$1,868	$1,911	$2,322	**$9,379**	**10%**
Total US Reported to FERC	**$2,523**	**$2,464**	**$2,315**	**$1,951**	**$2,131**	**$2,307**	**$2,617**	**$4,216**	**$3,314**	**$3,943**	**$4,112**	**$4,564**	**$7,012**	**$6,813**	**$8,796**	**$8,722**	**$10,827**	**$10,983**	**$14,289**	**$21,012**	**$19,150**	**$19,949**	**$21,808**	**$18,755**	**$100,673**	**12%**

Notes:

Not all ERCOT TOs filed FERC Form 1. Therefore, for 2010 through 2017, ERCOT's Transmission Project and Information Tracking (TPIT) data are provided. ERCOT's TPIT can be accessed at: http://www.ercot.com/gridinfo/sysplan

Data for 2010 through 2017 reflect actual utility membership in an ISO/RTO for a given year. Data for 1994 through 2009 reflect membership as of 2010. Investments shown in nominal dollars.

Data does not include transmission additions by entities that do not file FERC Form 1, except for ERCOT for 2010-2017, which is based on TPIT.

Sources:

Total Transmission addition figures are calculated using FERC Form 1 data in conjunction with EIA 861 data.

Table 2: Competitively-Developed Projects by Region and Selection Year ($million)

Year		CAISO	ISO-NE	MISO	NYISO	PJM	SPP	All FERC Jurisdictional ISO/RTOs	ERCOT	All ISOs/RTOs	Total US
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]=sum([2]:[7])	[9]	[10]=sum([8]:[9])	[11]
2013	[a]	$144	—	—	—	—	—	$144	—	$144	$144
2014	[b]	$148	—	—	—	$90	—	$238	—	$238	$238
2015	[c]	$425	—	—	—	$912	—	$1,337	—	$1,337	$1,337
2016	[d]	$133	—	$50	—	$471	$8	$662	—	$662	$662
2017	[e]	—	—	—	$181	$142	—	$323	—	$323	$323
Total Estimated Competitive Project Costs Selected (2013 - 2017)	[f]=sum([a]:[e])	$851	—	$50	$181	$1,615	$8	$2,705	—	$2,705	$2,705
Total Reported FERC Form 1 Investment in 2013 - 2017	[g]	$12,591	$7,488	$15,530	$2,592	$31,469	$6,202	$75,873	$10,213	$86,086	$100,673
Total Estimated Competitive Project Costs Selected in 2013-2017 (% of 2013-2017 Total Investment)	[h]=[f]/[g]	6.8%	0.0%	0.3%	7.0%	5.1%	0.1%	3.6%	0.0%	3.1%	2.7%

Notes:

[f]: Estimated Competitively-Proposed Project Costs reflect project cost estimates provided during Project Selection Years. Projects that have been canceled or put on hold are included.

[g]: Not all ERCOT TOs filed FERC Form 1. Therefore,ERCOT's TPIT reported cost data are shown. ERCOT's TPIT accessed from: http://www.ercot.com/gridinfo/sysplan

Sources:

[a]-[e]: Sources for Competitively-Proposed Project cost estimates are shown in the table 6, 7, 8, 9, and 11. Data for PJM comes from TEAC Project Statistics presentations for 2017 and 2018.

[g]: Calculated using FERC Form 1 data in conjunction with EIA 861 data, with the exception of ERCOT.

Table 3: Transmission Additions Subject to Full ISO/RTO Planning Processes

		Years Reviewed	FERC Jurisdictional Additions by Transmission Owners (nominal $million) *(based on FERC Form 1 Filings)*	Investments Approved Through Full ISO/RTO Planning Process (nominal $million)	% of Total FERC Jurisdictional Investments Approved Through Full ISO/RTO Planning Process	% of Total FERC Jurisdictional Investments With Limited ISO/RTO Review
		[1]	[2]	[3]	[4]=[3]/[2]	[5]= 1-[4]
CAISO	[a]	2014 - 2016	$7,528	$4,043	54%	46%
ISO-NE	[b]	2013 - 2017	$7,488	$5,300	71%	29%
MISO	[c]	2013 - 2017	$15,530	$8,068	52%	48%
NYISO	[d]	2013 - 2017	$2,592	n/a	n/a	n/a
PJM	[e]	2013 - 2017	$31,469	$14,458	46%	54%
SPP	[f]	2013 - 2017	$6,202	$4,226	68%	32%
Total	[g]	-	**$70,810**	**$36,095**	**53%**	**47%**

Notes:

[a]: CAISO data only reflects transmission additions/approved investments of PG&E, SCE, and SDG&E.

[d][3]: There is no data available on investments approved by NYISO.

[e]: Supplemental and Transmission Owner Initiated projects were excluded from these calculations, as they are not assesed for need or cost efficiency by PJM.

[f]: Values for 2013 and 2017 contain only partial December values, due to data limitations.

[g]: Totals in columns [2], [3] are for values as shown.

[g][4]: Percentage shown does not include NYISO.

[2]: Total FERC Form 1 transmission additions over indicated time periods.

[3]: Total value of transmission additions placed in-service over indicated time periods, approved through ISO/RTO processes. For annual data, please see supplemental table Table 21: Approved Investment By RTO.

[3][c]: MISO data reflects only fully completed projects, per MISO project tracking reports.

Sources:

[2]: Data are from FERC Form 1, analyzed in conjunction with EIA 861 data, shown in nominal dollars.

[3]: Shown in nominal dollars. Sources for each row are noted below.

[a]: Formal Complaint of California Public Utilities Commission, et. al. under Docket No. EL17-45.

[b]: https://www.iso-ne.com/about/key-stats/transmission/

[c]: MISO Transmission Expansion Plan (MTEP) In-Service Project List as of 1/9/2018. Accessed on 4/10/2018. A current version of the List is available on the MISO website.

[e]: PJM Cost Allocation Database was used for costs for Baseline Projects; PJM Construction Cost Database was used for Network upgrades.

Cost allocation database available at: http://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view

Construction Cost database available at: http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx

[f]: SPP STEP Reports (2014-2018).

Table 4: Competitive Transmission Project Eligibility for Processes of U.S. ISO/RTOs

		CAISO	ISO-NE	MISO	NYISO	PJM	SPP
		[1]	[2]	[3]	[4]	[5]	[6]
Types of Projects Eligible for Competition	[a]	Reliability, Economic, Public Policy	Reliability, Economic, Public Policy	Market Efficiency (MEP), Multi-Value (MVP)	Reliability, Economic, Public Policy	Reliability, Economic, Public Policy	ITP, High Priority, Interrigional
				Exclusions			
Exclusions for Reliability Projects	[b]		✓ (Based on Need Date)	✓ *		✓ (Based on Need Date)	✓ (Based on Need Date)
Exclusions for Local Cost Allocated Projects (per Order 1000)	[c]	✓	✓	✓	✓	✓	✓
Exclusion of Upgrades (per Order 1000)	[d]	✓	✓	✓	✓	✓	✓
				Exclusions Based on Voltage			
Voltage > 300 kV	[e]						
Voltage 200-300 kV	[f]			✓ ** (For MEP)			
Voltage 100-200 kV	[g]	✓		✓ ** *(For MEP)*		✓ ***	
Voltage < 100 kV	[h]	✓	✓	✓ **		✓ ***	✓

Notes and Sources:

Additionally, competitive transmission may be precluded in certain states, due to state Right of First Refusal (ROFR) provisions.

*****In MISO, projects that are **only** classified as Baseline Reliability Projects are locally allocated (regardless of voltage), making them ineligible for competitive processes. Projects designated as Baseline Reliability Projects **and** MEPs/MVPs are cost-allocated as though they are MEPs/MVPs.

******MISO limits competition to MEPs and MVPs; MEPs must have a total cost of at least $5 million and a minimum voltage of 230 kV; MVPs must have a total cost of at least $20 million and a minimum voltage of 100 kV; see MISO Tariff Attachment FF, Sections II.B. and II.C.

*******PJM has exceptions to these exclusions on lower voltage facilities for specific types of reliability violations. These exceptions are detailed in PJM Manual 14F Section 5.3.4.

[c] & [d]: Order No. 1000 did not mandate inclusion of Locally Cost Allocated projects or Upgrades.

[1][a][d][g][h]: CAISO Memo on Decision on the ISO 2016-2017 Transmission Plan, March 8, 2017, p. 8.

[1][c]: CAISO 2017-2018 Transmission Plan, p. 35.

[2][a][b]: ISO-NE Overview of the Transmission Planning Process and the Role of ISO New England, December 3rd, 2015 Consumer Liaison Group Meeting, pp. 8-9.

[2][c][d]: ISO New England Inc. Transmission, Markets, and Services Tariff Section II, Schedule 12, Transmission Cost Allocation on and After January 1, 2004, p. 371.

[2][h]: ISO New England Inc. Transmission, Markets, and Services Tariff Section II, Schedule 12, Transmission Cost Allocation on and After January 1, 2004, p. 109.

[3][a][c]: Transmission Planning Business Practices Manual, Effective Dec 1, 2017 pp. 21-22.

[3][b]: MISO Tariff Attachment FF Sections II.C and III.B.

[3][d]: MISO FERC Electric Tariff, Attachment FF, Section VII.A.

[3][f][g][h]: MISO Business Practice Manual 020, Section 7.4 and 7.5

[4][a][c][d]: NYISO Tariff OATT Attachment Y, 31.1.2, 31.1.4, 31.1.5, and 31.6.4.

[5][a][b]: PJM Manual 14F, Section 1.

[5][c][d][g][h]: PJM Manual 14F, Section 5.3.

[6][a][b][c][d][h]: SPP Open Access Transmission Tariff, Attachment Y, Section I.

Table 5: Summary of Experience with Competition in U.S. ISO/RTOs and Canadian ISOs in Alberta and Ontario

Regions		Governing Regulatory Order for Competition	Competitive Processes Completed	Process Type	Awards	Cost-containment	Competitively-Solicited Projects
[1]		[2]	[3]	[4]	[5]	[6]	[7]
FERC-jurisdictional							
CAISO	[a]	Order 1000	10	Projects	10	Yes	Gates-Gregg, Imperial Valley, Sycamore-Peñasquitos,Delaney-Colorado River, Estrella, Wheeler Ridge Junction, Suncrest, Spring, Harry Allen-Eldorado, Miguel
ISO-NE	[b]	Order 1000	0	Solutions	0	No	n/a
MISO	[c]	Order 1000	2	Projects	2	Yes	Duff-Coleman, Hartburg-Sabine
NYISO	[d]	Order 1000	2	Solutions	3	No	Western New York, AC Transmission Public Policy
PJM	[e]	Order 1000	16	Solutions	139	Yes*	Thorofare, Artificial Island, ApSouth Market Efficiency
SPP	[f]	Order 1000	1	Projects	1	No	Walkemeyer-N. Liberal
Total FERC-jurisdictional	**[g]**		**31**		**155**		
Other U.S.							
ERCOT	[h]	State Directed	1	Projects	186	No	CREZ (4), Houston Import (1)
Canadian							
AESO	[i]	2010 Amendments to T-Reg	1	Projects	1	Yes	Fort McMurray West
IESO	[j]	Ontario Energy Board	2	Projects	2	No	East-West Tie Line, Wataynikaneyap Project

Notes:

* Only Artificial Island included cost containment.

[4]: Under the competitive "projects" process, the transmission planning region identifies regional transmission needs and selects the more efficient or cost-effective transmission solutions to meet those needs. The transmission planning region then solicits proposals from qualified transmission developers and chooses from among the developers and designates a selected transmission developer as eligible to use the regional cost allocation method to develop the selected transmission project. Under the "sponsor" process, the transmission planning region identifies regional transmission needs. Then, qualified transmission developers may propose transmission projects to meet those identified regional transmission needs. The transmission planning regions selects the more efficient or costeffective transmission solution to meet each identified regional transmission need, which can be a solution proposed by a transmission developer or one that the transmission planning region designed itself.

[2][i]: In November 2009, Alberta passed the Electric Statutes Amendment Act (also known as Bill 50), which designated four transmission projects as Critical Transmission Infrastructure (CTI) and provided the Alberta Cabinet the authority to designate future projects as CTI. Following this in 2010, an amendment to Alberta's Transmission Regulation (T-Reg) was passed, mandating the AESO develop a competitive process for certain transmission projects, including those designated as CTI. In 2012, the Electric Utilities Amendment Act (also known as Bill 8) was passed, which removed the Cabinet's authority to designate CTI and also required projects to obtain AUC approval; Per the AESO's mandate and subsequent legislative developments (Bill 8), AESO is responsible for running its competitive processes, and the selected projects are required to obtain AUC approval.

For more details see: https://www.aeso.ca/assets/Uploads/Competitive-Process-Recommendation-Paper-Final.pdf
https://www.energy.alberta.ca/AU/electricity/AboutElec/Pages/Transmission.aspx
http://www.energyregulationquarterly.ca/articles/competition-in-electricity-transmission-two-canadian-experiments#sthash.YwmqCqGq.FDZeXnxS.dpbs

[2][j]: The Ontario Energy Board (OEB) first developed the Framework for Transmission Project Development Plans (EB-2010-0059) in August 2010. In 2011, Ontario's Ministry of Energy recommended the OEB engage its previously developed transmission development designation policy to "select the most qualified and cost-effective transmission company to develop the East-West Tie".

For more details see: http://www.energyregulationquarterly.ca/articles/competition-in-electricity-transmission-two-canadian-experiments#sthash.YwmqCqGq.pBATi6ye.dpbs

Sources:

[4][a],[c]-[f]: FERC 2017 Transmission Metrics Staff Report, p8. The Project model is is referred to as the Competitive Bidding model and the Solution model is referred to as Sponsorship model.

[4][h]: ERCOT: The Texas Competitive Renewable Energy Zone Process, September 2017, p17-18.

Table 6: Competitive Transmission Projects Summary

ISO/RTO		Project	Year of Decision	Selected Developer	Award to Incumbent?	Cost Containment?	ISO's Planning Estimate/Lowest Cost Proposal from Incumbent	Cost of Selected Proposal (incl. any non-competitive portion) ($Million)	Updated Cost of Project ($Million) (Current Estimate)	Selected Proposal % Change vs. ISO or Incumbent Estimated Cost
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
CAISO	[a]	Gates-Gregg	2013	PG&E/MidAmerican w/ Citizen Energy	Yes	No	$145	$130	n/a	-10%
	[b]	Imperial Valley	2013	Imperial Irrigation District	No*	Yes	$25	$14	n/a	-43%
	[c]	Sycamore-Peñasquitos 230kv Transmission Line Project	2014	SDG&E w/ Citizen Energy	Yes	No	$221	$108	n/a	-51%
	[d]	Delaney-Colorado River Project	2015	DCR Transmission	No	Yes	$300	$280	n/a	-7%
	[e]	Estrella Substation Project	2015	NextEra	No	Yes	$45	$20	n/a	-56%
	[f]	Wheeler Ridge Junction	2015	PG&E	Yes	No	$140	$60	$32	-57%
	[g]	Suncrest	2015	NextEra	No	Yes	$75	$37	n/a	-50%
	[h]	Spring Substation	2015	PG&E	Yes	No	$45	$28	$21	-38%
	[i]	Harry Allen-Eldorado Project	2016	Desert Link	No	Yes	$144	$133	n/a	-8%
	[j]	Miguel	2014	SDG&E	Yes	n/a	$40	n/a	$58	n/a
MISO	[k]	Duff-Coleman 345 kV	2016	LS Power w/ Big Rivers	No	Yes	$59	$50	n/a	-15%
	[l]	Hartburg-Sabine Junction 500 kV	2018	NextEra	No	Yes	$122	$104	n/a	-15%
NYISO	[m]	Western NY Public Policy Transmission	2017	NextEra Energy Transmission	No	No	$232**	$181	n/a	-22%
	[n]	AC Transmission Public Policy Segment A	2019	North America Transmission and NYPA	No	n/a	n/a	$750	n/a	n/a
	[o]	AC Transmission Public Policy Segment B	2019	Niagara Mohawk and New York Transco	Yes	n/a	n/a	$479	n/a	n/a
PJM	[p]	Artificial Island Project	2015	LS Power (w/ PSEG incumbent substation work)	No	Yes	$692	263 - $283	$280	-61%
	[q]	AP South Market Efficiency	2016	Transource, BGE, and Allegheny Power	No****	No	n/a	$320	$328	n/a
	[r]	Thorofare Project	2015	Transource	No****	No	n/a	$60	$72	n/a
	[s]	136 Projects Awarded to Incumbents (132 upgrades)	2014-2017	Various	Yes	n/a	n/a	n/a	n/a	n/a
SPP	[t]	North Liberal – Walkemeyer 115 kV	2016	MKEC	Yes	No	$17	$8	Cancelled	-50%
US Total	[u]						$2,030	$1,246	$790	**-39%**
AESO	[v]	Fort McMurray West 500 kV Transmission Project	2014	Alberta PowerLine Limited Partnership	Yes	Yes	$1,800	$1,430	$1,614	-21%
IESO	[w]	East West Tie Line	2013	NextBridge Infrastructure	No	No	$928***	$439	$777	-53%
	[x]	Wataynikaneyap Power	2015	Fortis	No	n/a	n/a	n/a	n/a	n/a
Total	**[y]**						$4,758	$3,115	$3,182	**-35%**

Notes:

*While Imperial Irrigation District (the selected developer of the Imperial Valley project) is the incumbent in the Imperial Valley Region, it is not a CAISO PTO and thus not an incumbent within the CAISO footprint.

**NYISO did not develop an ISO planning estimate for this project, the shown estimate instead reflects the lowest cost proposal from incumbent.

***IESO did not develop an ISO planning estimate for this project, the shown estimate instead reflects the cost developed by incumbent prior to competition.

**** Transource is a joint venture between AEP and Great Plains Energy.

[u]: Does not include NYISO costs. See also tab NYISO Competitive Projects.

[7][w]: Reflects Incumbent Proposal with comparable design as Selected Proposal See tab Ontario Competitive Projects for more details.

[8][9],[y]: Does not include Miguel Project and Wataynikaneyap Power Project.

[10][a]-[j]: We compare the cost of the selected proposal to the CAISO's upper end estimate as it is generally more consistent with the TO-prepared estimates as submitted to the CPUC. See Table 18.

[10][y]: Does not include Miguel Project and Wataynikaneyap Power Project. Selected proposal cost for Artificial Island Project taken as the average of selected proposal cost range.

Table 7: MISO Competitive Project Summary

Project		Year of Decision	Selected Developer	Incumbent?	MISO's Planning Estimate ($million)	Selected Proposal Cost ($million)	Selected Proposal Cost % Change vs. MISO's Planning Estimate	Cost Containment	Key Selection Factors
[1]		[2]	[3]	[4]	[5]	[6]	[7]=[6]/[5]-1	[8]	[9]
Duff-Coleman 345 kV	[a]	2016	LS Power w/ Big Rivers	No	$58.9	$49.8	-15%	Yes	Selection based on "firm rate base cap" and low ATRR estimate.
Hartburg-Sabine Junction 500 kV	[b]	2018	NextEra	No	$122.4	$103.9	-15%	Yes	Selection based largely on cost caps and cost containments, including forgoing of AFUDC and CWIP.

Notes:

MISO's 2017 quarterly update indicates the current cost estimate of the project at $53.8 million, which is equivalent to the cost of selected proposal inflated to in-service year dollars.

Sources:

Year of project selection, selected proposal, planning developer, and selected proposal cost reported in MISO selection reports.

Cost Containment for Duff-Coleman in Selected Developer Agreement by and between Republic Transmission, LLC and Midcontinent Independent System Operator, Inc., Original Sheet No. 20

[6]: NextEra estimated the total implementation cost of the project to be $114.8 million. MISO noted that the equivalent implementation cost would be $103.9 million in 2018 dollars.

Table 8: SPP Competitive Project Summary

Project		Year of Decision	Selected Developer	Incumbent?	SPP's Planning Estimate ($million)	Selected Proposal Cost (2015 $million)	% Change of selected proposal cost vs. SPP's Planning Estimate	Cost Containment	Key Selection Factors	Other Notes
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
North Liberal – Walkemeyer 115 kV	[a]	2016	MKEC	Yes	$16.8	$8.3	-50%	No	Consistently strong application across all metrics.	-Several competing proposals offered at lower costs than SPP's Planning Estimate for the Project. -Project has been cancelled.

Sources:

Year of project selection, and selected proposal cost data reported in SPP IEP Recommendation Report for the project. Planning estimate reported in SPP RFP.

Selected proposal information as reported in SPP issued NTC for the project (SPP-NTC-200385).

Cost containment from IEP Transmission Provider Internal Report for RFP000001, pg. 31

Table 9: CAISO Competitive Projects Summary

Project		Year of Decision	Selected Developer	Incumbent?	Lower Bound of CAISO's Planning Estimate Range ($million)	Upper Bound of CAISO's Planning Estimate Range ($million)	Midpoint of CAISO's Planning Estimate Range	Selected Proposal Cost ($million)	Updated Cost of Project ($million) (current estimate)	Selected Proposal Cost % Change vs. CAISO's Lower Bound Estimate	Selected Proposal Cost % Change vs. CAISO's Upper Bound Estimate	Cost Containment	Key Selection Factors	Other Notes
[1]		[2]	[3]	[4]	[5]	[6]	[7]=([5]+[6])/2)	[8]	[9]	[10]=[8]/[5]	[11]=[8]/[6]	[12]	[13]	[14]
Gates-Gregg	[a]	2013	PG&E/MidAmerican w/ Citizen Energy	Yes	$115	$145	$130	$130	n/a	13%	-10%	No	Has existing ROW that could contribute to project	Project is on hold
Imperial Valley	[b]	2013	Imperial Irrigation District	Yes	$25	$25	$25	$14	n/a	-43%	-43%	Yes	Substantially lower cost cap than other proposal	Project has been cancelled
Sycamore-Peñasquitos 230kv Transmission Line Project	[c]	2014	SDG&E w/ Citizen Energy	Yes	$111	$221	$166	$108	n/a	-2%	-51%	No	Has existing ROW and franchise rights that could contribute to the project	
Delaney-Colorado River Project	[d]	2015	DCR Transmission	No	$300	$300	$300	$280	n/a	-7%	-7%	Yes	Lowest projected revenue requirement, binding cost containment on capital costs and partial containment of ROE	
Estrella Substation Project	[e]	2015	NextEra	No	$35	$45	$40	$20	n/a	-43%	-56%	Yes	Reasonable cost cap and lowest interconnection costs	
Wheeler Ridge Junction	[f]	2015	PG&E	Yes	$90	$140	$115	$60	$32	-33%	-57%	No	PG&E's maintenance headquarters is near by	
Suncrest	[g]	2015	NextEra	No	$50	$75	$63	$37	n/a	-25%	-50%	Yes	Most robust cost containment; materially lower capital costs.	
Spring Substation	[h]	2015	PG&E	Yes	$35	$45	$40	$28	$21	-20%	-38%	No		
Harry Allen-Eldorado Project	[i]	2016	Desert Link	No	$144	$144	$144	$133	n/a	-8%	-8%	Yes	Strongest binding cost containment. Robust capital/construction costs and ROE caps	
Miguel	[j]	2014	SDG&E	Yes	$30	$40	$35	n/a	$58		n/a	Unknown	Only one qualified project sponsor	Project is in service
Total	[k]				**$935**	**$1,180**	**$1,058**	**$811**	**$110**	**-10%**	**-29%**			

Sources:

[2],[3],[12]: Year of project selections,selected developer, and cost containment based on CAISO selection reports, with the exception of the Miguel project. Miguel's selection year and selected proposal per CAISO market notice.

[5],[6]: Estimates reported in selection reports and CAISO functional specification documents.

[8]: Selected proposal cost estimates for rows [a], [e], and [g] from Approved Project Sponsor Agreements. Selected proposal cost estimates for rows [b] and [i] from CAISO selection reports. Selected proposal cost estimates for rows [f] and [h] from PG&E's response to data request CPUC-PGE-053 in FERC Docket No. ER16-2320-002. Selected proposal cost estimates for row [c] from its Approved Project Sponsor Agreement and its CPUC Certificate of Public Convenience and Necessity decision filing. Selected proposal cost estimate for row [d] from its CPUC Certificate of Public Convenience and Necessity application.

[9]: Updated cost estimates for row [j] from SDG&E's TO4 Cycle 5 Volume 2 filing. Updated cost estimates for rows [f] and [h] from PG&E's response to data request CPUC-PGE-053 in FERC Docket No. ER16-2320-002.

[c]: Competitive solicitation originally selected overhead design but was subsequently changed to an underground design after project was awarded to selected developer.

Table 10: Selected PJM Competitive Projects Summary

Project	Year of Decision	Selected Developer	Incumbent?	Selected Proposal Cost ($million)	Lowest-Cost Proposal Cost from Incumbent ($million)	Updated Project Cost ($million) (Current Estimate)	Updated Project Cost % Change vs. Incumbent Proposal Cost	Cost Containment	Key Selection Factors	Other Notes
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Artificial Island Project [a]	2015	LS Power (w/ PSEG incumbent substation work)	No	$263 - $283 (Total Cost of Selected Proposal, Competitive + Incumbent Portion)	$692	$280	-60%	Yes	Per PJM Selection Report, LS Power's Selected Proposal provided the strongest cost containment offer.	-Initially, PSE&G proposed 14 (of 26) solutions for Aritficial Island, with costs ranging from a low of $692 million to a high of $1.5 billion. Of the 26 proposed projects, only two satisfied the performance criteria specified, so according to the selection white paper "PJM undertook additional engineering review to identify the most effective solution to stated needs, taking into consideration the elements of submitted proposals." -PSE&G ultimately provided a proposal with an estimated project cost of $277-$285 million, with $221 million in cost containment for specific work. However, this proposed project came only after PJM had analyzed the most effective components of the 26 initial proposals and applied its findings to the existing proposals. -LS Power's selected proposal cost contains a $146 million cost containment for their portion of the project. Adding incumbent substation work to LS Power's competitive portion increases the total cost of the solution to the $263 million to $283 million range. LS Power's cost containment contained fewer exceptions than PSE&G's cost containment, which led to the recommendation of LS Power's project.
AP South Market Efficiency [b]	2016	Transource, BGE, and Allegheny Power	No	$320	n/a	$328	n/a	No	15-year congestion and load payment savings estimate of $619 million and $269 million.	
Thorofare Project [c]	2015	Transource	No*	$60	n/a	$72	n/a	No	n/a	
136 Incumbent Projects (132 upgrades) [d]	2014-2017	Various	n/a	n/a	n/a	$955	n/a	n/a	n/a	

Notes:

Summary only includes projects wherein PJM selected Non-Incumbent developers.

[a]: Illustrated cost reduction in [8] for Artificial Island Project based on comparison of LS Power's current project cost and Incumbent PSEG's lowest cost project initially proposed.

[c]: *The Selected Developer for the Thorofare Project is Transource, which is a joint venture between AEP and Great Plains.

Sources:

[a][2]-[6]: Year of project selection, selected developer, selected proposal cost, incumbent proposal cost, and total project capital cost estimates from Artificial Island Project Recommendation White Paper.

[a][7]: Updated project cost estimates from Artificial Island White Paper, dated April 2017.

[a][9]: Designated Entity Agreement between PJM Interconnectioin, LLC and Northeast Transmission Development, Schedule E, pg. 25.

[b][2]-[6]: Year of project selection, selected developer, and selected proposal cost from the August 2016 TEAC Recommendations to the PJM Board.

[b][7],[c][7]: Updated Project costs from the PJM Transmission Construction Database.

[b][9]: Definition of Schedule E on PJM Manual 14F: Competitive Planning Process Section 8: Project Evaluation, pg. 40

[c][2]-[5]: Transmission Expansion Advisory Committee Reliability Analysis Update, September 10, 2015, available at: https://www.pjm.com/-/media/committees-groups/committees/teac/20150910/20150910-teac-reliability-analysis-update.ashx

[d]: Number of projects comes from Craig Glazer's 2018 WIRES meeting presentation. The value of these projects is calculated from subtracting the $663 million total cost of the Artificial Island, ApSouth Market Efficiency, and Thorofare projects from the $1,615 million in projects approved that were eligible for competition, presented in the PJM TEAC's 2017 Project Statistics presentation.

Summary of Initial Artificial Island Competitive Proposals

Project ID	Incumbent?	Proposal Sponsor	Proposal Sponsor Estimated Cost ($million)
P2013_1-7A	Yes	PSE&G	$1,371
P2013_1-7B	Yes	PSE&G	$1,372
P2013_1-7C	Yes	PSE&G	$1,372
P2013_1-7D	Yes	PSE&G	$831
P2013_1-7E	Yes	PSE&G	$692
P2013_1-7F	Yes	PSE&G	$879
P2013_1-7G	Yes	PSE&G	$1,034
P2013_1-7H	Yes	PSE&G	$1,177
P2013_1-7I	Yes	PSE&G	$1,353
P2013_1-7J	Yes	PSE&G	$915
P2013_1-7K	Yes	PSE&G	$1,066
P2013_1-7L	Yes	PSE&G	$1,250
P2013_1-7M	Yes	PSE&G	$1,548
P2013_1-7N	Yes	PSE&G	$1,289
P2013_1-1A	No	Virginia Electric and Power Company	$133
P2013_1-1B	No	Virginia Electric and Power Company	$126
P2013_1-1C	No	Virginia Electric and Power Company	$202
P2013_1-2A	No	Transource	$213 - $269
P2013_1-2B	No	Transource	$165 - $208
P2013_1-2C	No	Transource	$123 - $156
P2013_1-2D	No	Transource	$788 - $994
P2013_1-3A	No	First Energy	$410.7 (Only FirstEnergy portion)
P2013_1-4A	No	PHI Exelon	$475
P2013_1-5A	No	LS Power	$116.3 - $148.3
P2013_1-5B	No	LS Power	$170
P2013_1-6A	No	Atlantic Wind	$1,012

Source:
Artificial Island Project Recommendation White Paper
Accessed at: http://www.pjm.com/~/media/committees-groups/committees/teac/postings/artificial-island-project-recommendation.ashx

Table 11: NYISO Competitive Project Summary

Project		Year of Decision	Selected Developer	Incumbent?	Lowest-Cost Proposal from Incumbent ($million)	Selected Proposal Cost Estimate (2017 $million)	Cost Containment	Selected Proposal Cost % Change vs. Incumbent Proposal
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]
Western NY Public Policy Transmission	[a]	2017	NextEra	No	$232	$181	No	-22%
AC Transmission Public Policy Segment A	[b]	2019	North America Transmission and NYPA	No	n/a	$750	n/a	n/a
AC Transmission Public Policy Segment B	[c]	2019	Niagara Mohawk and New York Transco	Yes	n/a	$479	n/a	n/a

Notes:

NYISO relied on the overall benefits of the project, in addition to cost considerations, in making its final selection of the selected proposal. With regard to benefits, NYISO estimated the selected proposal's production cost savings at $274 million, and that of the lowest Incumbent Proposal at $229 million (In 2017 dollars). Overall, the Selected Proposal provided greater production cost savings at lower capital cost compared to the Incumbent Proposal.

Sources:

[a][2]-[6]: Western New York Public Policy Planning Report.

[a][7]: No cost cap included in NextEra's proposal.

[b],[c]: AC Transmission Public Policy Transmission Plan Report, April 8, 2019.

Table 12: NYISO Competitive Project Experience:
Additional Production Cost Savings of Western NY Public Policy Transmission

Competitive Process Participant		Capital Cost Estimate (2017 $million)	Production Cost Savings (2017 $million)	Net Customer Costs (2017 $million)
[1]		[2]	[3]	[4]=[2]-[3]
Selected Proposal (NextEra; Non-Incumbent)	[a]	$181	$274	-$93
Best Incumbent Proposal	[b]	$232	$229	$3
NextEra Benefit vs. Best Incumbent Proposal				**Total Net Customer Savings**
Net Customer Cost Advantage of Selected Proposal	[c]			$96
% Advantage	[d]			41%

Notes:

[c]: Difference between Net Customer Costs of Selected Proposal and Best Incumbent Proposal.

[d]: Calculated as total cost benefit advantage of selected proposal cost divided by capital cost estimate of Best Incumbent Proposal.

Sources:

Western New York Public Policy Planning Report

Table 13: AESO Competitive Project Summary

Project		Year of Decision	Selected Developer	Incumbent?	AESO Planning Estimate +/- 50% (CAD million)	Selected Proposal Cost (2019 CAD million)	Updated Cost Estimate (current estimate, 2020 CAD million)	Selected Proposal Estimated Cost % Change Vs. AESO Planning Estimate	Cost Containment	Key Selection Factors
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]=[6]/[5]-1	[9]	[10]
Fort McMurray West 500 kV Transmission Project	[a]	2014	Alberta PowerLine Limited Partnership	Hybrid	$1,800	$1,430	$1,614	-21%	Yes	Cost Savings was the key selection factor. AESO noted that the Fort McMurray West competition cost savings for Alberta ratepayers were "conservatively estimated to be over $400 million".

Notes:

[a]: Cost reduction in [8] evaluated as Selected Proposal Cost vs. AESO's Planning Estimate since AESO's Selection Report and Recent CEO Presentation entitled "Competitive Electricity Market & Emerging Transmission Expansion Policies" indicates that Project is a "Fixed Price Contract" with cost changes permitted if in predetermined Agreements. The increase in updated project cost shown is due to change in project route from the East Route to the longer West Route, per approval by the regulator. The new West Route was not pre-defined at the time of Project award. Additionally, the updated cost reflects allowed inflation adjustments.

Sources:

[1]-[6],[8]: https://www.aeso.ca/grid/competitive-process/fort-mcmurray-west-500-kv-transmission-project/

[7]: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2017/21030-D02-2017.pdf

[9]: An Innovative Hybrid PPP for Electric Transmission Infrastructure in Alberta, A Case Study, pg. 8, footnote 20

Table 14: Ontario Competitive Project Summary

Project		Year of Decision	Selected Developer	Incumbent?	Incumbent Proposal with Comparable Design as Selected Proposal (2020 CAD million) *Inflation Reflected*	Selected Proposal Cost (2012 CAD million) *Inflation Reflected*	Updated Cost Estimate (current estimate, 2020 CAD million)	Updated Cost Estimate % Change relative to Incumbent Proposal with Comparable Design as Selected Proposal	Cost Containment	Other Notes
[1]		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
East West Tie Line	[a]	2013	NextBridge Infrastructure	No	$928	$439	$777	-16%	No	The cost of Incumbent Proposal with comparable design as the Selected Proposal was $724.7 million (2010 CAD). When inflated to in-service year (2020) CAD, this value increases to $928 million. The updated cost estimate of the selected proposal shown is reflective of development cost, construction cost and inflation adjustments.
Wataynikaneyap Power	[b]	2015	Fortis	No	n/a	n/a	n/a	n/a	n/a	-Fortis owns 49% Wataynikaneyap Power, in conjunction with 22 First Nations communities -Joint venture was developed to connect remote First Nations communities, currently powered by diesel generators, to the electric grid

Notes:

[a][5]-1: In 2010, Hydro One (incumbent) developed 6 potential designs for the East West Tie Line project. Cost estimates for the six options ranged from $439 million to $1216 million. The double circuit option, entitled "L1",with a cost estimate of $724.7 million (in 2010 CAD) is the most comparable option in design and line length to NextBridge's Selected Proposal project from the competitive solicition of 2013 for the East West Tie Line. Because these six Hydro One options were developed prior to the development of the competitive procurement process for the project, the benefit of competition is assessed as a comparison of the Selected Proposal cost relative to the Hydro One's most comparable design option cost, when Hydro One first proposed a solution for the project.

[a][5]: For comparison with the Updated Cost Estimate of the Selected Proposal, cost of Hydro One's comparable option is adjusted to reflect an assumed annual inflation of 2.5%.

[a][6]: Adjusted from $419.06MM estimated cost at designation to reflect revised 2020 in-service date.

[a][7]: Reflects CAD$104 million increase due to new scope requirements and CAD$122 million increase due to development phase project refinements.

[a][2]-[4],[6]-[7],[10]: NextBridge Application for Leave to Construct, accessed at: http://www.rds.oeb.ca/HPECMWebDrawer/Record?q=CaseNumber=EB-2017-0182+And+WebDocumentType:%22Application%20and%20Evidence%22&sortBy=recRegisteredOn-&pageSize=400.

[a][9]: No cost cap included in NextBridge's proposal.

Table 15: PJM Cost Escalations Breakdown for Projects with available Initial and Latest Cost Estimates
(2014 - 2017 In Service or Under-Construction Baseline & Network Upgrade Projects)

	Initial TO Cost Estimate *(provided at time of PJM Advisory Committee recommendation)*	Latest TO Cost Estimate *(reported by PJM Cost Allocation Tracking)*	Cost Escalation
	[1]	[2]	[3]=[2]/[1]-1
2014	$822	$971	18%
2015	$1,722	$2,124	23%
2016	$768	$940	22%
2017	$382	$485	27%
Total	**$3,695**	**$4,520**	**22%**

Notes:

Table reflects only projects with reported intial cost data *and* latest cost data.

Projects are categorized into years based on PJM provided "DisplayServiceDate" variable in PJM Transmission Construction Status Database.

Supplemental and TO Initiated projects are only notified to TEAC but standard reporting of costs are not tracked by PJM's Transmission Construction Status Database, so they are not reflected in this data.

[3]: Variance percentages are estimated for all 2014-2017 In-service / Under-Construction Baseline Reliability and Network projects reported by PJM to have experienced a cost change (i.e., projects that are reported to have experienced either a cost escalation or an underrun); Approximately 28% of 2014-2017 In-Service/Under-Construction Baseline and Network Upgrade Projects are reported to have expereinced cost changes since Project Approval by PJM's TEAC Recommendation committee. Other 72% of PJM's reported projects are reported with the exact same initial and latest estimates in PJM's Transmission Construction Status Database. It is unclear whether these reported latest estimated costs in PJM's database are appropiately reflective of actual cost changes in Projects' cost estimates, therefore they have been excluded from this cost variance calculation.

Sources:

[1]: Initial cost estimates from 2014-2017 PJM TEAC Staff Whitepapers
http://www.pjm.com/committees-and-groups/committees/teac.aspx

[2]: Latest Cost Estimates from PJM Transmission Construction Status Database
http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx

Table 16: Historical Cost Escalations for Completed SPP Transmission Projects ($million)

		Initial Cost Estimate (submitted to SPP by TO)	Latest Cost Estimate Tracked by SPP	Cost Escalation
		[1]	[2]	[3]=[2]/[1]-1
SPP Balanced Portfolio	[a]	$691	$831	20%
SPP Priority Projects	[b]	$1,145	$1,349	18%
ITP Portfolio Projects with Final Cost Estimates (2012 to 2017)	[c]	$192	$211	10%
Total	[d]	**$2,028**	**$2,391**	**18%**

Notes:

[1]: Initial Cost Estimates are E&C cost estimates provided by TO's upon projects first inclusion in the SPP Quarterly Project Tracking Report.

[2]: Final Cost Estimates are E&C cost estimates provided by TO's upon projects completion, in the SPP Quarterly Project Tracking Report.

[b]: Note that in October 2010, 6 months after the projects initial approval, the Board approved a $271 million dollar cost increase to the projects.

[c]: $1 billion of in-service SPP ITP projects do not provide final costs in the Quarterly Project Tracking Report, and thus cannot be used to calculate cost variances, so they are excluded from this row.

Sources:

[a]: Balanced Portfolio data comes from the 2017 Q2 SPP Quarterly Project Tracking Report.

[b]: Priority Projects data comes from the 2017 Q4 SPP Quarterly Project Tracking Report.

[c]: ITP Portfolio data comes from the 2019 Q1 SPP Quarterly Project Tracking Report, Appendix 1.

Table 17: MISO Historical Cost Escalations for Base Reliability, MVP, and MEP Facilities for which Initial and In-Service/Under-Construction Cost Estimates are Available

(2015-2017 In-Service, 2018 In-Service or Under-Construction)

Quarter	Number of Facilities	TO Estimate Provided to MISO After Approval ($million)	TO Latest Cost Estimate Provided to MISO ($million)	Cost Escalation
	[1]	[2]	[3]	[4]=[3]/[2]-1
2015Q1	23	$769	$707	-8%
2015Q2	25	$909	$935	3%
2015Q3	7	$33	$29	-12%
2015Q4	0	$0	$0	-
2016Q1	6	$27	$48	75%
2016Q2	45	$291	$304	4%
2016Q3	18	$231	$289	25%
2016Q4	41	$702	$901	28%
2017Q1	3	$6	$8	29%
2017Q2	16	$196	$255	30%
2017Q3	30	$422	$353	-17%
2017Q4	13	$155	$207	33%
2018Q1	77	$2,217	$3,017	36%
Total	**304**	**$5,960**	**$7,053**	**18%**

Notes:

[2]: Initial cost estimate submitted by TO.

[3]: TO facility cost estimate after the project is in-service or has a planned status of under-construction.

Sources:

Cost estimates shown are for in-service & under construction Base Reliability, MVP, and MEP facilities, as reported in MISO's MTEP Appendix A Status Trackers.

Table 18: Historical Cost Escalations for CAISO Transmission Projects

Project		TO Cost Estimate submitted to CAISO/CPUC ($million)	Lower End of CAISO Estimate ($million)	Upper End of CAISO Estimate ($million)	Submitted Cost Estimate relative to Upper End of CAISO Estimate (% change)	Estimated Final Cost ($million)	Estimated Final Cost relative to TO's CAISO/CPUC Submitted Cost (% change)	Estimated Final Cost relative to CAISO Upper End Estimate (% change)
[1]		[2]	[3]	[4]	[5]=[2]/[4]-1	[6]	[7]=[6]/[2]-1	[8]=[6]/[4]-1
Wheeler Ridge Junction 230kV Substation	[a]	$155	$90	$140	11%	$151	-3%	8%
Spring 230kV Substation	[b]	$48	$35	$45	7%	$98	104%	118%
Estrella 230kV Substation	[c]	$34	$35	$45	-24%	$96	179%	113%
Martin 230kV Bus Extension	[d]	$129	$85	$129	0%	$285	121%	121%
Midway-Andrew 230kV Project	[e]	$154	$120	$150	2%	$198	29%	32%
Lockeford-Lodi Area 230kV Development	[f]	$103	$80	$105	-2%	$163	58%	55%
Oro Loma 70kV Reinforcement	[g]	$46	$46	$46	0%	$30	-34%	-34%
ECO Substation	[h]	$273	-	-	-	$410	50%	-
New TL ES-Ash #2	[i]	$22	-	< $50M	-	$5	-78%	-
IV West Generator Interconnection (Q608)	[j]	$2	-	-	-	$1	-47%	-
Talega-Add Synchronous Condensers	[k]	$64	$58	$72	-11%	$81	26%	12%
Shunt Reactor on Suncrest 500kV Bus	[l]	$11	-	-	-	$10	-10%	-
Pio Pico Energy Ctr. Gen. Interconnect	[m]	$9	-	-	-	$10	2%	-
Relocate South Bay Substation	[n]	$129	$129	$129	0%	$121	-7%	-6%
Talega Bank 50 Replacement	[o]	$6	$5	$6	-8%	$2	-61%	-64%
TL13821 and TL13828-Fanita Junction Enhancement	[p]	$41	-	<50M	-	$35	-15%	-
Encina Bank 61	[q]	$11	-	<50M	-	$8	-29%	-
Tehachapi	[r]	$1,800	-	-	-	$2,350	31%	-
Total	[s]	**$3,037**	**$683**	**$867**	**0%***	**$4,053**	**33%**	**41%****

Notes:

These Projects are not the complete universe of CAISO projects. CAISO typically reports a high and low estimate. The table reports CAISO's high estimate as it is generally more consistent with the TO-prepared estimates as submitted to the CPUC.
*Percentages exclude projects with no specific CAISO estimates.
**Percentages exclude projects with no specific CAISO estimates. <50M is not considered a specific estimate.
[2][a]-[g]: PG&E cost estimate is cost information submitted to CAISO at time of project review. These values differ from the CAISO approved cost presented in its TPP.
[6][a]-[g]: PG&E estimated final cost is project forecasted cost at completion and excludes contingency costs, but includes risk.
[a],[b]: These projects have competitive and noncompetitive portions, both of which are represented in the values presented here. Note that in both cases, noncompetitive portions have experienced escalations, while competitive portions have experienced underruns.
[2][h]-[q]: SDG&E Initial Cost Estimate is the estimated cost of the project as of its first inclusion on AB970.
[6][h]-[q]: SDG&E Final Cost is the FERC ratebase dollars for the project.
[2][r]: The initial cost estimate is the cost first approved by CAISO in 2007 transmission plan
[8]: We compare the estimated final cost to the CAISO's upper end estimate as it is generally more consistent with the TO-prepared estimates as submitted to the CPUC, as shown above.
Measuring cost escalations relative to the CAISO's lower end estimate would yield higher percentage increases.

Sources:

[a]-[g]: Exhibit PUC-0015 in FERC Docket No. ER16-2320-000; excludes Northern Fresno 115 kV Reinforcement because the project experienced significant scope changes.
[h]-[q]: SDG&E Responses to data requests issued in FERC No. EL17-45. Only projects approved by CAISO or the CPUC and CAISO were included in this sample. Additionally, only projects with initial and final cost estimates were included in this sample.
[r]: Initial cost data from 2016 - 2017 CAISO Draft Transmission Plan Stakeholder Meeting, page 13 comment 2b. Latest Cost Estimate reported in SCE's 2016 Q4 Quarterly Report.

Table 19: Historical Escalations for ISO-NE Transmission Projects

Project		Intial TO Cost Estimate ($million)	Final TO Cost Estimate ($million)	Cost Escalation
[1]		[2]	[3]	[4]=[3]/[2]-1
Scobie-Tewksbury	[a]	$123	$120	-2%
Wakefield-Woburn	[b]	$107	$137	28%
Mystic Woburn	[c]	$75	$82	9%
Stoughton Cable Project (Phase I & II)	[d]	$213	$317	49%
Southwest Connecticut	[e]	$690	$1,415	105%
Norwalk Reliability	[f]	$128	$234	83%
Worcester Reliability	[g]	$7	$33	377%
Long Term Lower SEMA	[h]	$107	$105	-2%
Millstone DCT elimination	[i]	$22	$39	76%
NEEWS – Greater Springfield	[j]	$350	$759	117%
NEEWS – Rhode Island Reliability	[k]	$150	$315	110%
Merrimack Valley / North Shore Project	[l]	$43	$62	45%
NEEWS - Interstate Reliability	[m]	$400	$542	35%
Stamford Reliability	[n]	$49	$42	-15%
Total	**[o]**	**$2,464**	**$4,201**	**70%**

Notes:
[o]= sum of [a]-[n]
[a]-[c]: ISO NE Regional System Plan(RSP) Pool Transmission Facility estimated costs.
[d]-[n]:Based on Transmission Cost Allocation(TCA) filing cost estimate and RSP Project listing's estimate.

Sources:
[a]-[c]: ISO NE Final RSP 18 Project List - March 2018 https://www.iso-ne.com/system-planning/system-plans-studies/rsp/
[d]-[n]:New Hampshire Transmission Greater Boston Cost Comparison January 2015 Presentation.

Table 20: Estimated Savings from Competitive Transmission Planning Processes to Date

RTO		ISO or Incumbent Estimated Cost of Competitive Projects ($million)	Selected Proposal Estimated Cost of Competitive Projects ($million)	Average % Customer Cost Savings for Competitive Projects as Proposed	Average Historical Escalation of Transmission Projects (%)	Expected Cost if Competitive Projects were not subject to Competition ($million)	Potential $ Savings from Competition w/o proposal price escalation ($million)	Potential % Savings without Cost Escalation of Competitive Projects
		[1]	[2]	[3]=[2]/[1]-1	[4]	[5]=[1]x(1+[4])	[6]=[5]-[2]	[7]=[6]/[5]
CAISO	[a]	$1,180	$833	**29%**	41%	$1,667	$834	**50%**
ISO-NE	[b]	n/a	n/a	n/a	n/a	n/a	n/a	n/a
MISO	[c]	$181	$154	**15%**	18%	$215	$61	**28%**
NYISO	[d]	$232	$181	**22%**	n/a	$232	$51	**22%**
PJM	[e]	$692	$280	**60%**	22%	$847	$567	**67%**
SPP	[f]	$17	$8	**50%**	18%	$20	$11	**58%**

Notes:

[1]: Values for CAISO, MISO, and SPP are ISO estimates. Values for PJM and NYISO are incumbent costs. Values reflect 10 projects in CAISO, two projects in MISO, and one project in each of the other ISOs/RTOs.

[2]: Values are either the final cost estimate, latest cost estimate, or selected proposal cost estimate, depending on availability and relevance, taking precedence in that order.

[e]: PJM competitive project only reflects Aritificial Island Project.

[d][3]: NYISO relied on the overall benefits of the project, in addition to cost considerations, in making its final selection of the selected proposal. With regard to benefits, NYISO estimated the selected proposal's production cost savings at $274 million, and that of the lowest incumbent proposal at $229 million (In 2017 dollars). Overall, the Selected Proposal provided greater production cost savings at lower capital cost compared to the Incumbent proposal.

Sources:

[1],[2]: Please see tables 7 - 12.

[4]: Please see Tables 15, 16, 17, and 18.

Table 21: Approved Investment By RTO

Approved Transmission Investment ($million)		2012	2013	2014	2015	2016	2017	Total
CAISO (PG&E, SDG&E, and SCE only)	[a]	n/a	n/a	$1,611	$1,430	$1,002	n/a	$4,043
ISO-NE	[b]	$500	$1,400	$500	$800	$500	$2,100	$5,800
MISO	[c]	$1,125	$1,679	$1,843	$2,010	$1,498	$1,038	$9,193
NYISO	[d]	n/a	n/a	n/a	n/a	n/a	n/a	n/a
PJM	[e]	$1,354	$1,063	$3,643	$4,766	$3,623	$1,364	$15,811
SPP	[f]	$859	$369*	$1,816	$856	$939	$246**	$5,084
ERCOT	[g]	n/a	n/a	$218	$1,100	$2,000	$805	$4,123
Annual Total ($million)	[h]	**$3,837**	**$4,511**	**$9,630**	**$10,963**	**$9,562**	**$5,553**	**$44,056**

Notes:

[c]: There may be components of incomplete projects that have been placed in-service over these years, that are not reported by MISO in their in-service project list and therefore are not reported in these aggregates.

*Value as of December 3, 2013

**Value as of December 20, 2017

Sources:

[a]: Formal Complaint of California Public Utilities Commission, et. al. under EL17-45.

[b]: https://www.iso-ne.com/about/key-stats/transmission/

[c]:MISO Transmission Expansion Plan (MTEP) In-Service Project List as of 1/9/2018. Accessed on 4/10/2018. A current version of the List is available on the MISO website.

[e]: PJM Cost Allocation Database was used for costs for baseline; PJM Construction Cost Database was used for Network upgrades. Supplementary, and transmission owner initiated projects were excluded from these calculations.

Cost allocation database available at: http://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view

Construction Cost database available at:http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx

[f]: 2013-2018 SPP STEP Reports.

[g]: ERCOT Quick Facts sheets, 2015-2018, accessed at: http://www.ercot.com/news/presentations.

Table 22: Summary of Experience with Competition in UK

Region	Competitive Processes Completed	Summary of Completed Processes	Non-incumbent Awards	Cost-Containment	Key Notes
[1]	[2]	[3]	[4]	[5]	[6]
Great Britain	3	-The UK Office of Gas and Electricity Markets (OFGEM) has completed three competitive tender processes to connect up to 48 GW of offshore wind. -In tender Rounds 1 (November 2010) & 2 (March 2012), investors competed to own, finance and operate transmission assets, after construction for largely radial connections to the shore. -In Round 3 (February 2014), investors again competed to own, finance, and operate offshore transmission built by offshore wind developers, but were also provided the option to propose offers to construct transmission for offshore wind developers. Round 3 offshore wind farms were further from the shore, making transmission design more complex.	15	Fixed Revenue. *Ofgem determines allowed revenue based on benchmarks for allowed Cost of Capital*	On behalf of OFGEM, Cambridge Economic Policy Associates estimated NPV savings related to Rounds 1-3: *- Round 1 savings for nine projects ranging from £244 to £469 million* *- Round 2 savings for four OFTO projects ranging from £326 to £595 million* *- Round 3 savings for two OFTO projects ranging from £102 to £154 million* Types of Savings as a % of value of projects: *- Financial savings 8-11%* *-Operational savings 18-25%* Total net savings 23 - 34% -Rounds 1 & 2 were completed under a transitional regime, where only generation developers could build transmission systems. -Round 3 is occuring under the enduring regime, which allows for either generation developers or OFTOs to build transmission systems. -Rounds 4 & 5 have been initiated, but not completed.

Sources and Notes:

[3]: https://www.globaltransmission.info/archive.php?id=27887

[4]: https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission/offshore-transmission-tenders, non-incumbent awards identified by looking at each individual tender.

[6]: https://www.ofgem.gov.uk/publications-and-updates/evaluation-ofto-tender-round-2-and-3-benefits

Table 23: Cost Savings for Competitive Projects in CAISO and MISO

RTO	Scenario	Escalation Reflected		ISO or Incumbent Estimated Cost of Competitive Projects ($million)	Selected Proposal Estimated Cost of Competitive Projects ($million)	Average % Customer Cost Savings for Competitive Projects as Proposed	Average Historical Escalation of Transmission Projects (%)	Expected Cost if Competitive Projects were not subject to Competition ($million)	Potential $ Savings from Competition w/o proposal price escalation ($million)	Potential % Savings without Cost Escalation of Competitive Projects
		[1]		[2]	[3]=(1+[1])x[2]	[4]=[3]/[2]-1	[5]	[6]=[2]x(1+[5])	[7]=[6]-[3]	[8]=[7]/[6]
CAISO	No Escalation	0%	[a]	$1,180	$833	29%	41%	$1,667	$834	50%
CAISO	5 Years of Inflation	13%	[b]	$1,180	$942	20%	41%	$1,667	$725	43%
CAISO	Historical Escalation	41%	[c]	$1,180	$1,177	0%	41%	$1,667	$490	29%
MISO	No Escalation	0%	[d]	$181	$154	15%	18%	$215	$61	28%
MISO	5 Years of Inflation	13%	[e]	$181	$174	4%	18%	$215	$41	19%
MISO	Historical Escalation	18%	[f]	$181	$182	0%	18%	$215	$33	15%

Notes:

[2]: Values for CAISO and MISO are ISO estimates. Values reflect 10 projects in CAISO and two projects in MISO.

[3]=(1+[1])x[2]: Values are either the final cost estimate, latest cost estimate, or selected proposal cost estimate, depending on availability and relevance, taking precedence in that order.

Sources:

[2][a]: Please see Table 9.

[2][d]: Please see Table 7.

[5]: Please see Tables 17, and 18.

Table 24: Estimated Savings Across All

Region		Estimated Cost Savings	No. of Projects	Estimated Cost of Selected Proposals	Notes
		[1]	[2]	[3]	[4]
CAISO	**[a]**	29-50%	9	$833 million	Selected proposal costs compared to CAISO initial cost estimate; assuming a range of cost escalation for the selected bid of between zero to the level of historical average cost escalation of transmission projects in CAISO (+41%)
MISO	**[b]**	15-28%	2	$154 million	Selected proposal costs compared to MISO's initial cost estimate; assuming a range of cost escalation for the selected bid of between zero to the historical average cost escalation of transmission projects in MISO (+18%)
PJM	**[c]**	60-67%	1	$280 million	Selected proposal cost (including necessary incumbent upgrades) compared to the lowest-cost solution offered by incumbent in the initial proposal window; assuming a range of cost escalation of between zero to the historical average cost escalation of transmission projects in PJM (+22%)
NYISO	**[d]**	22%	1	$181 million	Selected proposal cost compared to lowest-cost bid from incumbent
IESO	**[e]**	16%	1	CAD 777 million	Selected proposal cost compared to bid from incumbent
AESO	**[f]**	21%	1	CAD 1,614 million	Selected proposal cost compared to AESO initial cost estimate; costs of the selected bid later increased due to changes in route
UK	**[g]**	23-34%	15	~£3,000 million	Selected bid cost estimate compared to merchant and regulated counterfactuals estimated by Ofgem
Brazil	**[h]**	~25% (20-40%)	Many	$28 billion	Based on Brazil's experience since 1999 holding auctions for all projects over 230 kV; over 50,000 km of lines built through this process

Sources:

SPP has been excluded due to cancelled project.

[a]: See Table 9: CAISO Competitive Projects Summary.

[b]: See Table 7: MISO Competitive Project Summary.

[c]: See Table 10: Selected PJM Competitive Projects Summary.

[d]: See Table 11: NYISO Competitive Project Summary.

[e]: See Table 14: Ontario Competitive Project Summary.

[f]: See Table 13: AESO Competitive Project Summary.

[g]: See Table 22: Summary of Experience with Competition in UK.

[h]: See ANEEL Transmission Auction Results.