Attachment I

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Competitive Transmission Development Technical Conference	))	Docket No. AD16-18-000

RESPONSIVE SUPPLEMENTAL COMMENTS OF
LSP TRANSMISSION HOLDINGS, LLC

LSP Transmission Holdings, LLC ("LS Power") submits the following Responsive Supplemental Comments to the Supplemental Comments filed August 8, 2019 by a group of incumbent transmission owners – Ameren, Eversource Energy, ITC Holdings Corp., National Grid USA, and PSE&G ("Incumbent TOs")[1] – that collectively have a long history of opposing the Commission's transmission competition reforms, both before issuance of those reforms and after.[2]

The purpose of the Incumbent TOs' supplemental comments was to add into the Commission record a report questioning the value of transmission competition, prepared at their behest by Concentric Energy Advisors.[3] The focus of the Concentric Report was an effort to

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1 Although the incumbent transmission owners referred to themselves in the filing as "DATA (Developers Advocating Transmission Advancements)" and to DATA as "an ad-hoc coalition comprised of transmission owners" a search of the Commission's elibrary going back to 2000 indicates no prior submissions from this ad hoc coalition, the members of which are identical to the entities for which the Concentric Report was prepared. Supplemental Comments of Developers Advocating Transmission Advancements, filed August 9, 2019 in Docket AD16-18-000, at 1, fn1 ("Incumbent TO Comments"). The same group, again referencing the entities as DATA, has since filed comments in Docket No. PL19-3-000 adding the Concentric Report to that Docket.

2 Exhibit A to these comments is a partial listing of the various efforts of the Incumbent TOs or their affiliates to oppose additional competition for transmission facilities.

3 *See*, Report: Building New Transmission: Experience To-Date Does Not Support Expanding Solicitations, released June 2019 by Concentric Energy Advisors ("Concentric

diminish the value of transmission competition by challenging the findings of a report by the Brattle Group, *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value.*[4]

The Brattle Group has thoroughly reviewed the Concentric Report and has issued a report titled *Response to Concentric Energy Advisors' Report on Competitive Transmission* ("Brattle Response"), August 2019, attached as Exhibit B to these comments. The Brattle Response lays out in detail the flaws in Concentric's critique of the original Brattle Study.

Since Incumbent TOs have a lot to lose through competition it is understandable that they are continuing to seek ways to discount the benefits of competition. As noted in LS Power's Comments in PL19-04-000, a combination of just three of the supporters of the flawed Concentric Report has projected $12 billion in new transmission investment over a 4 year period, with all the incumbent transmission owners referenced in LS Power's PL19-04-000 comments projecting upwards of $80 billion in transmission rate base additions over that 4 year period.[5] But if the Incumbent TOs have a lot to lose, ratepayers have even more to lose as every dollar

Report") and "Prepared For: Ameren, Eversource Energy, ITC Holdings Corp., National Grid USA, and PSEG."

4 Submitted in this Docket June 7, 2019 "Benefits of Competition Report.".

5 *See*, Initial Comments of LSP Transmission Holdings II, LLC, filed June 26, 20019 in Docket No. PL19-4-000, at 3, showing Transmission Only Capital Investment of PSEG at $5 billion 2019-2023, ITC at $3.7 Billion 2018-2022 and Eversource at $3.3 billion 2019-2023. In total, the incumbent transmission owners referenced in LS Power's Comments in PL19-4-000 reflected more than $80 billion.

spent by the Incumbent TOs on transmission additions will be paid for by those ratepayers, not the Incumbent TOs, or Concentric.

Under Section 206 of the Federal Power Act[6] the Commission is charged with protecting those ratepayers. Section 206 mandates that the Commission take action to address not only unjust and unreasonable rates, but also "practices" that could impact those rates. Brattle's Report found that even when competition is conservatively estimated to lead to ratepayer savings of only 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."[7] The Incumbent TOs rely on the Concentric Report to challenge the level of savings available, but if only half those saving ($4 billion) or one-quarter ($2 billion) were available, the Commission would still be obligated to act because practices have been identified that are resulting in excess rates.

The Incumbent TOs state that, "to the extent that policymakers consider expanding competitive solicitations or making other changes to the requirements of Order No. 1000, they need accurate information on results to-date – including project costs, cost cap commitments and exclusions."[8] LS Power could not agree more. LS Power has no hesitancy in putting the best available information before the Commission in this Docket, or any other Docket or hearing process the Commission may commence. Because that information will unequivocally show, as

6 16 U.S.C. § 824e.

7 Benefits of Competition Report at 13 [emphasis added].

8 Incumbent TO Comments at 3.

the Commission projected in Order No. 1000,[9] and the United States Court of Appeals for the District of Columbia Circuit upheld, that ratepayers benefit from competition for transmission facilities.

Notwithstanding the inferences of the Incumbent TOs' comments, nothing in the Concentric Report changes the proven fact that competition benefits ratepayers, just as Incumbent TO Ameren told the Commission in this very Docket.[10] The Incumbent TOs argue that "the addition of the Concentric Report to this record will provide the Commission with a more complete picture of the experience with competitive solicitations to date, as well as cost performance of incumbent transmission owners."[11] What that "complete picture" will show is that in order to challenge the conclusions of the Brattle Report the Concentric authors' relied "on

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[9] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000*, FERC Stats. & Regs. ¶ 31,323 at P 44 (2011)("Order No. 1000"), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 ("Order No. 1000A"), *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S. C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (Order No. 1000).

[10] In the Post Technical Conference Comments of Ameren Services Company, filed October 3, 2016 in Docket AD16-18-000, Ameren stated: "Ameren believes that including cost containment provisions in project proposals provide cost certainty and risk mitigation to transmission customers. Ameren also believes that cost containment provisions, even when coupled with incentives like CWIP, abandonment, hypothetical capital structures and ROE adders to address the additional risk associated with the competitive transmission development process in general, and cost containment provisions in particular, can produce a "win-win" for customers and developers alike." *Id*. at 2-3. Ameren went on to note "The transfer of project risk away from the customer is the key benefit of cost containment provisions which have been advanced under the competitive transmission process. Through the use of cost containment provisions developers are able to further differentiate their transmission project proposals by increasing price certainty for customers." *Id*. at 4.

[11] Incumbent TO Supplemental Comments at 3.

inappropriate and misleading cost comparisons, a misrepresentation of the available transmission cost data and facts, and a misunderstanding of [the Brattle] analysis."[12] Brattle addresses each of the alleged shortcomings in its Response and demonstrates why the Concentric analysis is fundamentally flawed and obviously results driven. As the Incumbent TOs suggest, the Commission should look thoroughly at the full picture. LS Power will not address each of Brattle's rebuttals to the Concentric here, instead encouraging the Commission's thorough review of the Brattle Response.

LS Power has never hesitated to let the results of competition, and the results from a lack of competition, speak for themselves. As Ameren noted in its Post Technical Conference Comments in this Docket, competition and the cost containment provisions it brings "can produce a 'win-win' for customers and developers alike."[13] Notwithstanding evidence of this win-win for consumers when competition has occurred, the Concentric Report twists those results in an effort to diminish the clear distinction between transmission rates when competition occurs and when it does not. While the Brattle Response addressed many of these efforts, LS Power will note other areas where the Concentric Report shows the flaws of the Incumbent TOs' position. Specifically, Concentric's attempts to discount the value of cost caps and other cost shifting provisions. Its efforts in this regard show the results-driven nature of the Concentric Report.

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12 *See*, Response to Concentric Energy Advisors' Report on Competitive Transmission, The Brattle Group, August 2019, attached as Exhibit A.

13 Ameren Comments at 2-3.

In Table 9 of its Report Concentric recaps the "Summary of Cost Caps, Concessions, and Commitments" from the Midcontinent System Operator, Inc.'s solicitation for the Duff-Coleman Project. That summary has been widely shared as it shows nicely the type of rate concessions that are available when transmission additions are subject to competition, with 10 of the 11 Respondents offering proposals that contained some form of cost containment. Concentric nevertheless seeks to discount the ratepayer benefit of those concessions by vague references to "exceptions" to cost caps from "some proposals."[14] Of course each proposal was different but Concentric's effort to downplay the ratepayer value of the proposals and their respective cost caps required that it ignore two important points: (i) the actual selected proposal (rather than "some proposals" that were not selected) had a firm cost cap with limited exclusions and the cost cap has been filed with the formula rate;[15] and (ii) despite access to tremendous volumes of Incumbent TO data Concentric showed no cost caps offers, with exceptions or not, for a single non-competed incumbent transmission project. Also, not surprisingly, missing from the Concentric Report is reference to the Duff-Coleman proposals from the Incumbent TOs. Four of five members of "DATA" provided proposals for the Duff-Coleman EHV 345 kV Competitive

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14 Concentric Report at 16. Not surprisingly, missing from the Concentric Report is reference to the Duff-Coleman proposals from the Incumbent TOs. Four of five members of "DATA" provided proposals for the Duff-Coleman EHV 345 kV Competitive Transmission Project: Ameren Transmission Company of Illinois, GridAmerica Holdings, Inc. (a subsidiary of National Grid), ITC Midcontinent Development, LLC and Public Service Enterprise Group Inc. Given that 10 of 11 proposals contained some form of cost-containment, at least three of these four Incumbent TOs themselves made cost containment proposals when required to compete.

15 *Republic Transmission, LLC*, 167 FERC ¶61,215 (2019).

Transmission Project: Ameren Transmission Company of Illinois, GridAmerica Holdings, Inc. (a subsidiary of National Grid), ITC Midcontinent Development, LLC and Public Service Enterprise Group Inc. Given that 10 of 11 proposals contained some form of cost-containment, at least four Incumbent TOs themselves made cost containment proposals when required to compete.

Thus, when there is competition, multiple cost cap proposals are evaluated, selected and reflected in rates, and when there is not competition, ratepayers bear all the risk. Even Concentric cannot challenge that undeniable fact, and that fact alone requires that the Commission look anew at the limitations on competition that have resulted in Brattle's finding that notwithstanding Order No. 1000 only 3% of transmission investment has been subject to the competition the Commission found essential to ensuring just and reasonable rates. The experience to date with competitive transmission solicitations provides abundant evidence that developers across the country stand ready, willing and able to offer a wide range of binding cost containment commitments when they are given the opportunity to do so. In addition to being essential to ensuring just and reasonable rates, competition is the only means by which transmission developers will have the opportunity to provide these binding ratepayer protections.

II. CONCLUSION

It is settled law that barriers to transmission competition prohibit the Commission's determination of just and reasonable rates for transmission.[16] There is also clear evidence that when competition is available transmission developers, including incumbent developers, offer

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16 *S. C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

risk shifting cost containment provisions that provide a "'win-win' for customers and developers alike."[17] With $80 billion in new transmission investment projected by incumbent transmission owners over the next four years,[18] the time for the Commission to act is now or the potential savings from competition will be lost to the barriers that the Commission found could lead to unjust and unreasonable rates. The impact of the lost benefits of competition will negatively impact ratepayers for decades.

Respectfully submitted,

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17 Ameren Post Technical Conference Comments at 2-3.

18 It should not be lost on the Commission that the incumbent transmission owners, as publicly traded companies, could only project the transmission investment they project that they will build in the next few years because they believe that investment will not be subject to competition.

CERTIFICATE OF SERVICE

I hereby certify that I have this 11th day of September 2019 caused the foregoing document to be served upon each person designated on the official Service List compiled by the Secretary in this proceeding.

By: /s/ Michael R. Engleman

EXHIBIT A

EXHIBIT A

RM10-23-000

1. Comments of Midwest ISO Transmission Owners,[1] submitted September 29, 2010 in Docket No. RM10-23-000 at 13-64 (making various arguments for retaining excusive incumbent construction rights).
2. Comments of the New England Transmission Owners[2] submitted September 29, 2010 in Docket No. RM10-23-000 at 12 (requesting that the Commission not take any action in the NOPR to limit incumbent transmission owner rights to build ISO-NE approved projects).
3. Comments of National Grid submitted September 29, 201- in Docket No. RM10-23-000 at 2-3 and 15-20 (arguing "It would be inconsistent with the Commission's overall objectives to damage the existing planning process in New England by fundamentally altering the role of the transmission owners that have built needed regional upgrades in recent years" and that New England Transmission Owners should maintain their right of first refusal.)
4. Comments of International Transmission Company d/b/a ITC*Transmission*, Michigan Electric Transmission Company, LLC ITC Midwest LLC, ITC Great Plains, LLC and Green Power Express LP, submitted September 29, 2010 in Docket No. RM10-23-000 at 13 (urging the Commission to reconsider its proposal to require removal of rights of first refusal from Commission jurisdictional tariffs and agreements).
5. Comments of Indicated PJM Transmission Owners,[3] submitted September 29, 2010 in Docket No. RM10-23-000 at 19 and 23-30 (arguing, among other reasons for maintaining exclusive transmission construction rights, that "instead of producing cost savings, the sponsorship model is likely to increase customer costs and risks" and that regulating construction rights is beyond the Commission's authority under the Federal Power Act.).
6. Comments of PSEG Companies, submitted September 29, 2019 in RM10-23-000 (arguing that the Commission's "drastic 'reforms' to transmission planning and contractually-established Rights of First Refusal ('ROFR') [ ] exceed its statutory authority under the Federal Power Act).
7. Reply Comments of Midwest ISO Transmission Owners (including Ameren), submitted November 12, 2010 in Docket No. RM10-23-000 (arguing at 10 "no showing that eliminating incumbent transmission owner construction rights will have

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[1] Included Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois.

[2] Included Northeast Utilities, now Eversource, and National Grid.

[3] Included Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC

this effect (increased or more efficient transmission development), and no party in this proceeding has shown that eliminating existing construction rights will result in increased or less costly transmission development" and at 17 "Eliminating Existing Construction Rights Will Not Lead to a Decrease in Transmission Costs".)

8. Reply Comments of PSE&G Companies, submitted November 12, 2010 in RM10-23-000 at 1 (arguing that "FERC has overstepped it legal authority in proposing radical "reforms" to transmission planning and to the Right of First Refusal ("ROFR") contained in FERC-approved Tariffs and Agreements.)
9. Joint Request for Rehearing of Certain Sponsoring PJM Transmission Owners,[4] submitted August 22, 2011 in Docket RM10-23-001 (arguing among other things, that a right of first refusal is not a practice affecting rates and therefore not within the Commission's jurisdiction).
10. Limited Request for Rehearing of the Midwest ISO Transmission Owners,[5] submitted August 22, 2011 in Docket No. RM10-23-001 (challenging the elimination of rights of first refusal as arbitrary and capricious.
11. Request for Rehearing and Clarification of the PSEG Companies, submitted August 22, 2011 in Docket No. RM10-23-001 (arguing in various ways that The Commission has overstepped its authority in its elimination of the Right of First Refusal ("ROFR") in jurisdictional tariffs).
12. Motion for Clarification and Request for Rehearing of Ameren Services Company, submitted August 22, 2010 in Docket RM10-23-001 (asserting that "the Commission chose to rely on unsubstantiated allegations of discrimination and vague assertions that injecting "competition" into the transmission planning process will somehow result in lower rates to consumers. The Commission ignored substantial evidence of the problems with its proposal to remove so-called rights of first refusal ("ROFRs") from jurisdictional tariffs and agreements, and therefore acted in an arbitrary and capricious manner in adopting its proposal to eliminate the ROFR in Order No. 1000.")

PETITIONS FOR REVIEW OF ORDER NO. 1000 REQUIREMENT TO ELIMINATE RIGHT OF FIRST REFUSAL:

1. Midwest ISO Transmission Owners[6]
2. PSEG
3. National Grid

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[4] Included Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

[5] Included Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois.

[6] Included Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois

ORDER NO. 1000 COMPLIANCE FILINGS

1. MISO

a. Midwest Independent Transmission System Operator, Inc.'s and MISO Transmission Owners' Compliance Filing for Order No. 1000, filed October 25, 2012 in Docket No. ER13-187-000 at 29-39 (arguing that elimination of the MISO Transmission Owners' right of first refusal is prohibited).

b. Request for Rehearing of the MISO Transmission Owners,[7] filed April 22, 2013 in Docket No. ER13-187-001 (asserted that the Commission Order denying their request to maintain a right of first refusal was "arbitrary, capricious, and fails the test of reasoned decisionmaking.")

c. *MISO Transmission Owners v. FERC*, 819 F.3d 329, 333 (7th Cir. 2016), cert. denied 127 S. Ct. 1223 (2017).

2. PJM

a. Compliance Filing by Indicated PJM Transmission Owners,[8] submitted October 25, 2012 in Docket No. RM10-23-000 (reassigned by FERC to Docket No. ER13-195-000)(noting that "PJM would not include the *Mobile-Sierra* submission in its eTariff filing" and then arguing that "the Commission should not consider any provisions to eliminate or limit the PJM ROFR contract provisions in its review of PJM's Order No. 1000 Compliance Filing, but instead reject such all-encompassing provisions as moot."

b. Request for Rehearing of The Indicated PJM Transmission Owners, submitted April 22, 2013 in Docket No. ER13-195-000 (challenging the Commission's rejection of the argument that any right of first refusal in the Consolidated Transmission Owners Agreement is not protected by the *Mobile-Sierra* Doctrine).

c. Petition for Review of Public Service Electric And Gas Company, filed July 14, 2014 in the United States Court of Appeals for the District of Columbia Circuit, Case No. 14-1136, dismissed by Order dated July 1, 2016.

3. ISO-NE

a. Order No. 1000 Compliance Filing of ISO New England Inc. and the Participating Transmission Owners Administrative Committee,[9] submitted October 25, 2012 in Docket No. ER13-193-000 at 18-27 (asserting that the ISO-NE Transmission

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7 Included Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois

8 Included Public Service Electric and Gas Company.

9 Noting that among the companies voting in favor of the filing were the "New England Power Company d/b/a National Grid; Northeast Utilities Service Company on behalf of its affiliates: NSTAR Electric Company, The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire."

Owners' exclusive right to build should not be removed, including arguments that costs are already minimized and asserting arguments (page 27) debunked yet by Brattle but repeated by Concentric).

b. Request for Rehearing and Motion for Clarification of Participating Transmission Owners Administrative Committee,[10] submitted June 17, 2013 (arguing that the Commission's rejection of their arguments for retention of a right of first refusal was erroneous).

c. Petition for Review of New England Transmission Owners, filed May 15, 2015 in the United States Court of Appeals for the District of Columbia Circuit, Case No. 15-1139, petitions for review denied April 18, 2017.

Changes in Cost Allocation to Avoid Competition

1. MISO

a. Midwest Independent Transmission System Operator, Inc.'s and MISO Transmission Owners Revisions to Cost Allocation for Baseline Reliability Projects, filed October 25, 2012 in Docket ER13-186-000 (revising the cost allocation for Baseline Reliability Projects in MISO because "Forcing MISO Transmission Owners to rely on nonincumbent transmission developers and a potentially lengthy competitive transmission developer selection process (not to mention, potentially protracted litigation brought by transmission developers that did not get selected in the MISO developer selection process) for local reliability projects poses an unreasonable risk to the reliability of the bulk power system and, by extension, to public safety. Thus, modifying cost allocation for BRPs as proposed in this filing is appropriate to provide the MISO Transmission Owners the ability to construct local transmission facilities without potentially running afoul of the Commission's clarifications in Order No. 1000-A . . ..")

2. PJM

a. Transmission Owners Schedule 12 Revisions Regarding Allocation of Costs for Local Transmission Owner Projects, submitted March 26, 2015 in Docket No. ER15-1387-000 (seeking to allocate all costs of projects in PJM to address FERC Form No. 715 criteria to the zone in which the project is located).

b. Request for Rehearing of PJM Transmission Owners, submitted June 22, 2015 in Docket No. ER15-1387-000 (arguing that the Commission erred in rejecting their cost allocation change).

[10] Noting that the filing is also filed on behalf of companies, including "New England Power Company d/b/a National Grid; Northeast Utilities Service Company on behalf of its affiliates: NSTAR Electric Company, The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire."

Comments Opposing Competition Submitted in AD16-18-000[11]

1. Opening Remarks of Kim C. Hanemann, Senior Vice President Delivery Projects & Construction, Public Service Electric And Gas Company, presented June 30, 2016 in Docket No. AD16-18-000 (noting that "You will not be surprised to hear that PSE&G does not view Order No.1000 as improving the transmission planning process or bringing value to customers. While PSE&G remains an avid supporter of markets and the efficiencies that competition can bring, there are certain areas that simply don't readily lend themselves to competition." And that "We were skeptical at its inception that Order No. 1000 would bring the intended benefits, no matter how well intentioned . . . our experience would suggest that Order No. 1000, as implemented, is not delivering the benefits it was designed to provide and may in fact have become more of an impediment than a help." And Concluding with "For the reasons discussed above, it is questionable whether Order No. 1000 will benefit consumers or simply add costs and inefficiencies. Our suggestion is that the Commission re-evaluate whether Order No. 1000 in its current form even makes sense.")
2. Post-Technical Conference Comments of Public Service Electric and Gas Company, filed October 3, 2016 in Docket No. AD16-18-000 (arguing that PSE&G strongly believes that cost caps, introduced as part of project proposals submitted under RTOs' Order No. 1000 bid processes, may not work and may not produce the promised benefits and instead may create unnecessary distractions from the RTO's planning mission" and suggesting that cost caps – at least for the time being – should be abandoned as a tool to analyze competing proposals under the Order No. 1000 regulatory framework." Also asserting that "many considerations counsel against the use of cost caps.") Submittal No. 20161003-5381.

OTHER RELEASES CRITICAL OF COMPETITION

1. Testimony of PSEG Chairman of the Board, President and CEO to the Energy and Commerce Committee, U.S. House of Representative, May 10. 2018 (asserting that "recent policies such as FERC's Order 1000 have introduced complexity and confusion in the transmission planning process, and should be re-examined before its worst consequences begin to manifest themselves to consumers," acknowledging that "the vast majority of transmission being built in PJM today is occurring outside the Order 1000 process" and that it might be "tempting" to "leave it intact and just find a

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[11] The MISO Transmission Owners, submitted Comments on May 31, 2016 in Docket No. AD16-18-000 (acknowledging that "cost containment provisions are methods for transferring risks from one party (i.e., the customers) to another (i.e., the developer), which can be beneficial" but raising questions regarding their value and arguing that "[c]ost containment or cost-capped bids should not be exclusively favored above bids that do not contain such measures." The MISO Transmission Owners for the filing including Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois

work-around" the Order, and concluding that "FERC should 'hit the pause button' on Order 1000 until and unless the planning regions can demonstrate significant benefits flowing from the Order. There should be no further Order 1000 activity in the form of open solicitations or windows until such a demonstration has been made."

EXHIBIT B

Response to Concentric Energy Advisors' Report on Competitive Transmission

Judy W. Chang, Johannes P. Pfeifenberger, J. Michael Hagerty, and Jesse Cohen
The Brattle Group
August 2019

Our April 2019 Report "*Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*"[1] summarized US and international experience with competitive solicitations for the development of major transmission projects. We discussed that using competitive solicitations in transmission development is estimated to save 20% to 30% of project costs compared to traditionally-developed transmission projects. As a result, we recommend that policymakers and system planners consider expanding the scope of competitive solicitations for transmission projects, estimating that doing so could save $8 billion over the course of five years. In June 2019, Emma Nicholson, Meredith Stone, and Danielle Powers of Concentric Energy Advisors issued a report about competitive transmission development entitled "*Building New Transmission: Experience To-Date Does Not Support Expanding Solicitations*" ("Concentric Report").[2] The Concentric Report is mostly a response to our April 2019 report.

The Concentric authors take exception to our conclusions by critiquing three aspects of our study. *First*, they note that none of the transmission projects recently subject to competitive solicitations have been completed, which makes those projects' final costs and associated savings attributable to the competitive process uncertain. *Second*, they conclude that the competitive solicitations undertaken to date have been time and resource intensive and therefore may not be worth doing if cost savings are uncertain. *Third*, they dispute that traditionally-developed transmission projects have experienced significant cost escalations relative to the projects' initial cost estimates. Based on these points, the Concentric authors state that our conclusion that competitive solicitations for transmission offer significant savings is "baseless" and that our findings should not be relied upon to justify an expansion of competitive solicitations for new transmission projects.

This memo responds to each of these points. We show that the Concentric authors' criticisms are based on inappropriate and misleading cost comparisons, a misrepresentation of the available transmission cost data and facts, and a misunderstanding of our analysis.

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1 https://www.brattle.com/news-and-knowledge/news/report-by-brattle-economists-discusses-the-benefits-of-competitive-transmission

2 https://ceadvisors.com/wp-content/uploads/2019/06/CEA_Order1000report_final.pdf

I. Experience with Completed Competitive Projects and Their Cost Escalations

The Concentric authors state that the competitive transmission projects initiated under the Order No. 1000 planning processes have not yet been completed, that their final costs are not yet known, that no conclusion about their cost savings can be made, and therefore policy makers should wait until those projects are completed before making a decision about the successes of these competitive transmission projects. While acknowledging that cost-containment provisions can cap some project cost escalations, the Concentric authors argue that the cost containment provisions offered in competitive solicitations are not comprehensive and they provide exclusions that allow the costs of the competitive projects to increase, which could erode a significant amount of our estimated savings. We disagree and offer three responses to this concern.

First, we recognize that some cost escalations often are unavoidable for transmission projects in general, and we account for the fact that some escalations likely will occur for competitive projects in our 20–30% range of estimated cost savings. We have considered the potential cost escalations that may occur even with the offered cost caps and cost containment provisions by estimating a range of cost escalations for competitive projects. The range includes: (a) no escalations above the capped cost of the winning bids; (b) inflation-based cost escalations (which are often allowed in cost caps); and (c) escalations that are equivalent to those experienced by traditionally-developed projects relative to their initial project cost estimates.

Second, there is significant experience with *completed* competitive transmission projects, and this experience documents a range of savings that is consistent with our own range of savings. We outline this experience in our report and in more detail below.

Third, even though cost caps and cost containment provisions provide for exclusions that allow for cost adjustments of competitively bid projects, having these cost containment provisions is superior in terms of limiting cost escalations than the experience of the traditionally-developed projects that do not have any such cost containment provisions.

A. Completed Competitive Transmission Projects Demonstrate Cost Savings of 20–30%

As we have summarized on pages 44 and 49–51 of our April 2019 report, there is significant experience with competitive transmission projects that have been completed. This experience is consistent with our estimated 20–30% cost savings:

- **Path 15, California**: The 84 mile, 500 kV project in CAISO was completed in 2004 on time and under budget at a cost of approximately $250 million, 18% below the incumbent's $306 million initial cost estimate. Recognizing that the completed cost of a traditionally-developed Path 15 project may have exceeded the $306 million initial cost estimate, the actual savings likely were larger than 18%.
- **Fort McMurray, Alberta**: The 508 kilometer, 500 kV project in Alberta was completed in March 2019 on budget ($1.6 billion) and three months ahead of schedule. According to

the Alberta Electric System Operators' estimation, the project provided Alberta ratepayers more than $400 million (21%) in cost savings.

- **UK Offshore Transmission**: The UK regulator estimated that three rounds of competitive solicitations undertaken since 2009 for offshore transmission projects resulted in cost savings ranging from £683 million to £1,092 million, or 23%–34% of the estimated project costs net of the cost of conducting the solicitations.
- **Brazil**: Since 1999, competitive auctions for 87 transmission projects (receiving 399 bids by 112 companies and consortiums) yielded estimated cost savings averaging 25% (based on a study prepared by Imperial College and University of Cambridge for the U.K. regulator).

B. Cost Containment Provisions Shift Some Cost Escalation Risks to the Project Developers Compared to Traditionally-Developed Projects

Transmission developers that compete in the solicitations conduct their due diligence to articulate carefully the risks that they are willing to take on and those that they cannot control. For example, as we have summarized on pages 41–42 of our report, the cost caps offered by LS Power affiliates in their successful bids illustrate the nature of these bid-based cost control mechanisms:

- **Artificial Island Project (PJM)**: The $146 million cost cap escalates with inflation until construction starts. The cost cap covers all LS Power–related construction costs, including those associated with obtaining permits, acquiring land, and environmental assessments and mitigations. Exclusions to the cost cap include force majeure–type events, taxes, financing costs, and any incremental costs to the project caused by PJM-directed changes.
- **Harry Allen–Eldorado 500 kV (CAISO)**: The project cost is capped at $147 million in 2020 dollars. Exclusions to the cost cap include force majeure events, financing costs, and cost increases caused by changes mandated by the ISO or from incumbent transmission owners at their substations.
- **Duff-Coleman 345 kV (MISO)**: The total rate base is capped at $58.1 million with exclusions for force majeure events, ongoing O&M costs, and material changes to the scope of work.

A range of similar cost containment provisions have been offered by most bidders to MISO's most recent competitive solicitations.[3]

The impact of cost containment provisions on the final costs for a project is illustrated by Nextera's "Suncrest" projects. The projects were bid at $37 million compared to CAISO initial project cost estimates of $50–75 million, as shown in Figure 12 of our report. When the interconnecting incumbent transmission owner raised concerns that necessitated the undergrounding of certain

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3 See cost cap summary of received bids in Table 3-3, page 24, of https://cdn.misoenergy.org/Hartburg-Sabine%20Junction%20500%20kV%20Selection%20Report296754.pdf

project components at an additional cost of approximately $5 million, NextEra committed that it will not seek to recover these costs if doing so were to exceed the binding cost cap.[4]

While they are certainly possible and desirable, we are not aware of similar cost containment mechanisms offered through the traditional transmission development process. By offering them as part of the competitive solicitations, competitive bidders help mitigate the cost escalation risks faced by transmission customers. Without such cost control commitments, customers are exposed to higher risks of cost escalations. Even if the cost control commitments do not transfer all of the risks to the developers, they at least remove some of the risks from customers compared to projects without such commitments. Thus, even though exclusions to the cost caps for competitively developed projects allow for some cost escalations, we anticipate these escalations will be less than the cost escalations for traditionally-developed projects without such cost containment commitments.

II. The Time and Resource Requirements of Competitive Solicitations

The Concentric authors claim on pages 26–32 of their report that competitive solicitations conducted to date were time and resource intensive, with time requirements as the most significant of "expenditures" of the competitive processes. The authors' claim, as presented in Table 12 of the Concentric Report, that between 113 and 1,498 days were required from project need identification to ISO/RTO board approval is quite misleading.

First, the Concentric Report exaggerates time requirements between need identification and ISO/RTO's board approval. As shown in Table 12 of the Concentric Report, 10 of the 17 competitive projects they reviewed took less than one year between the need identification and the ISO/RTO's board approval; three projects required only 55 to 174 days. This time requirement is not particularly consequential given that most major transmission projects require many years, sometimes five to ten years, to be placed in service after needs are first identified.

Second, the Concentric Report exaggerates how much time the competitive solicitation process adds to overall project development timelines. As shown again in Table 12 of the Concentric Report, the solicitation process itself tends to take only 3–6 months, not several years.

Third, several of the processes summarized in Table 12 of the Concentric Report have been conducted for the first time. Setting up such competitive processes will necessarily take more time initially, but they will become more streamlined as experience is gained over time. One example is MISO's competitive transmission process improvement effort. MISO reduced the total competitive process duration by nearly 12% between its first and second competitive solicitations

4 Testimony of Michael Sheehan on behalf of NextEra Energy Transmission West, LLC in CPUC Docket No. A.15-08—027, May 16, 2017, p. 28.

and has proposed further reductions of its competitive process timeline, particularly for smaller and less complex transmission projects.[5]

Fourth, the competitive timelines documented by the Concentric authors include efforts that would be similarly time consuming for traditionally-developed projects. For example, the MISO competitive process improvement discussion makes clear that part of the time requirement, up to 165 days,[6] is necessary to allow bidders to develop detailed project specifications, an effort that would also have to be undertaken by incumbent transmission owners when pursuing traditionally-developed projects.

Fifth, the Concentric authors focus attention on two special cases: PJM's and New York's processes. PJM's Artificial Island project, required significant time because the untested process had been held up in disputes between PJM, the incumbent transmission owner, and the non-incumbent bidders. Similarly, New York's process at the time included an evolving regulatory proceeding which involved state policymakers, regulators, and the ISO. Much of this was related to assessing the need for public policy projects in New York and would have required the same amount of time regardless of whether a competitive solicitation was used. In addition, the PJM and NYISO "solutions-based" processes are necessarily more time consuming because they require time for the bidders, not the ISOs/RTOs (as is the case in CAISO, MISO, and SPP), to identify specific transmission solutions that can address an identified need .

Finally, and most importantly, even if the competitive process adds some time to the overall development and completion of transmission projects, experience shows that competitive projects have come in on time and on budget. This more than makes up for the time spent up front to ensure the competitive process brings value to customers. It is the same reason why the developers for most large capital projects invest extra effort upfront to obtain the most cost-effective solutions and select the most efficient contractors to ensure that the overall costs are contained and risks are minimized.

The Concentric authors' claim that the *cost* of conducting competitive solicitations is prohibitively high is similarly unsupported. First, as we discuss on pages 37–39 of our report, the ISO/RTO cost of conducting competitive solicitations and the bidders' own cost of participating in these solicitations is incurred by the bidders and thus has to be recovered through their winning bids. As we have shown, the winning bids have been substantially below the projects' initial cost estimates. Second, the available data we provide in our report shows that the cost of solicitations to the ISOs/RTOs is modest compared to the likely cost savings, which is also consistent with international experience. For example, the UK regulator estimated that the total cost of solicitations adds approximately 4% to competitive project costs, with developers' costs estimated

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5 See MISO, Competitive Transmission Process Continuous Improvement Workshop II, July 18, 2019, Slides 18-20. Available at: https://cdn.misoenergy.org/20190718%20CTA%20Process%20Improvement%20Workshop%20Presentation364938.pdf.

6 *Id.*, Slide 20.

at approximately 2% of the project cost, the regulators' cost of conducting the solicitation adding 1%, and implementation costs by the network owner and system operator accounting for an additional 1%. Despite these added costs, the UK experience with offshore transmission shows that three rounds of competitive solicitations for 15 transmission projects achieved estimated savings averaging 23% to 34% of total project costs, including the cost of conducting the simulations.

III. Cost Escalations of Traditionally-Developed Transmission Projects

We found in our review of available transmission cost data that *initial planning cost estimates* are available for both competitively- and traditionally-developed projects and thus provide a common reference point for both types of transmission projects for estimating the potential cost savings of the competitive development process. For competitive projects, we compared the initial planning cost estimates to the price of winning bids as a first step and then added a range of plausible cost escalations to the cost of the winning bid due to the lack of completed projects. For traditional-developed projects, we compared the initial planning cost estimates to the cost of completed projects to determine typical cost escalations.

To estimate the potential cost savings for competitive projects developed since FERC Order 1000 was implemented, we compared the range of likely cost outcomes for competitive projects (relative to initial cost estimates) to the typical cost escalations of traditionally-developed projects (relative to initial cost estimates). The estimated cost savings from our analysis were then compared to the cost savings achieved in other jurisdictions that have already implemented competitive transmission solicitations.

The Concentric authors disagree with our approach of using the initial cost estimates as the common reference points for competitively- and traditionally-developed projects. First and foremost, they argue against comparing the completed costs of traditionally-developed projects to the initial planning estimates. They claim that it is more reasonable to compare the completed costs of traditionally-developed projects to updated estimates of project costs because the scope of the projects tends to change between the initial planning effort and later in the project development process.

As explained in more detail below, the Concentric authors' reliance on updated project costs instead of using a common reference point of the initial cost estimates accounts for most of the difference between our and the Concentric authors' estimates of cost escalations associated with traditionally-developed transmission projects. By using the updated cost estimates, which are generally higher than initial cost estimates, as the reference point for cost comparisons, the Concentric authors' calculated cost escalations for traditionally-developed projects are much lower than our estimates.

As an example, we estimated the cost escalations of a MISO transmission project using the two approaches to help illustrate how Concentric authors' use of updated cost estimates as the starting point substantially reduces their estimated cost escalations and produces misleading results:

- The MISO project was approved in 2008 at an initial cost estimate of $360 million and placed into service in 2016 for $493 million.
- We thus calculated a 37% cost escalation for this project.
- MISO provided updated cost estimates for the same project in 2014 at $430 million and again in 2015 at $448 million.
- Based on those values, the Concentric authors calculated a much lower cost escalation of only 12% based on the average of the updated project cost estimates ($439 million) and the completed costs ($493 million).

Since we use initial cost estimates to compare *both* competitively- and traditionally-developed transmission projects, we disagree that cost escalations of traditionally-developed projects should be measured only against updated estimates. Even if the initial cost estimates are only "conceptual" in nature, they should not consistently be lower than updated cost estimates. For instance, if the project cost estimates at the conceptual stage should be accurate within plus or minus 30% relative to the more refined project costs at a later stage, then some projects would have higher and some would have lower final costs compared to the "conceptual" project's initial cost estimates. But that is not the case and when Concentric authors use the updated cost estimates as the reference point, the cost escalations are always lower. The Concentric authors' approach suggests that initial cost estimates are generally too low compared to later, more refined cost estimates.

Importantly, if it were the case that initial cost estimates are generally too low (compared to the final project costs) and that experienced developers bidding into the competitive solicitations are aware of that, then the competitively-bid projects should also come in at a bid price *higher* than these initial project cost estimates. But that is not the case. Instead, the selected bids of competitively-developed transmission projects are typically *below* the initial project cost estimates—and these bids often include cost caps and other cost control commitments that limit cost escalations.

We discuss in more detail our assessment of the Concentric authors' analyses of cost escalations for each of the ISOs/RTOs below.

A. Concentric's Use of MISO's Cost Data Relies on Updated and Redundant Cost Estimates and Reduces Their Estimated Cost Escalations

In analyzing traditionally-developed MISO's projects, Concentric relies not only on updated cost estimates, but also uses duplicate data points for the very same projects. For example, the same project shows up with multiple updated cost estimates that gradually move toward final project cost. The chart and table below illustrates that approach.

Figure 1 below demonstrates in more detail the example from MISO that we discussed above. MISO approved the project in 2008 at an initial estimate of $360 million and then reported annual project cost updates from 2009 to 2015 until the project was completed in 2016 at a final cost of

$493 million, 37% higher than the initial cost estimate. The Concentric authors' analysis, presented on page 9 of their report, relies only on cost data for the period from 2014 through 2017. For the particular project, Concentric considered only the updated cost estimates from 2014 and 2015, disregarding the earlier cost updates, and the final 2016 costs to calculate a much lower cost escalation. Specifically, the Concentric authors' analysis considers the same project twice: first as a project with a 14% cost escalation based on its 2014 updated cost estimate; and then again as a project with a 10% cost escalation based on its 2015 updated cost estimate. This yields an average cost escalation of only 12%, which is about one third of the cost escalation when calculated based on the initial 2008 cost estimate at the time of MISO approval.

Figure 1: MISO Project Cost Escalation Example (Project 1024)

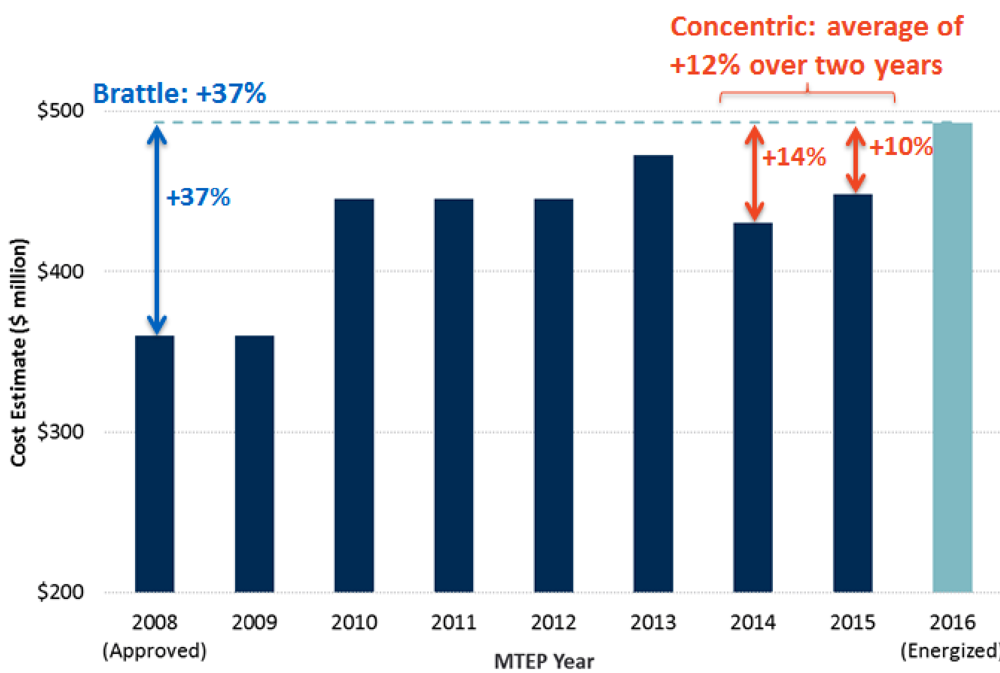

Table 1 shows two examples where the Concentric authors evaluated the cost changes repetitively and for the same project. By applying this approach to all projects listed in MISO's 2014–2017 project cost reports, Table 3 on page 9 of the Concentric Report estimates MISO cost escalations averaged only 5.9%—approximately one-third of the 18% overall cost escalation we estimated in Figure 21 and Table 17 of our report. This 5.9% Concentric cost escalation estimate is unreasonably understated and inconsistent with MISO's own reported cost escalations for major projects. For example, for the entire Multi Value Project (MVP) portfolio of transmission projects, MISO reported on page 5 of its 2017 MTEP MVP Update that "Total portfolio costs have increased from $5.56 billion in MTEP11 to $6.65 billion in MTEP17."[7] That is a 19.6% cost escalation compared to the initial 2011 cost estimates when the MVP portfolio was first approved.

[7] https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf

Table 1: MISO Project Cost Escalation Examples

	Project 1024	Project 4711
MTEP Year	Cost Estimate (in $million)	Cost Estimate
2008	$360 (as approved)	
2009	$360	
2010	$445	
2011	$445	
2012	$445	
2013	$473	
2014	$431	$20 (as approved)
2015	$448	$16
2016	In service	$14
2017		In service
Final Cost	$493	$15
Brattle Approach Cost Escalation using 2008 Initial Cost Estimate	37%	-29%
Concentric Approach Using 2014 and 2015 as Initial Cost Estimates	12%	-12%

Notes and Sources: As shown in this table, transmission cost estimates change year-to-year in the MTEP published data. It is not uncommon for cost estimates to increase annually as cost escalations become apparent. The Brattle approach calculates cost escalation between the final cost and the earliest available cost estimate. The Concentric approach calculates cost escalation annually for each project from 2014–2017, effectively averaging it out. So for this project 1024, the Brattle approach calculates escalation as 493/360 − 1 = 37%. The Concentric approach would calculate escalation as (493 + 493)/(431 + 448) − 1 = 12%.

B. The Concentric Analysis is Based on Unreliable Cost Data from PJM

In footnote 17 of the Concentric Report, the authors state, "Brattle excluded the 72% of projects where the initial and latest cost estimates were the same…. However, we found no documentation or basis to exclude these data." In contrast, the Concentric authors' analysis includes every PJM project even when there is no additional information about how the final project costs differ from the projects' initial cost estimates. This is because, for many of the projects in PJM's database, the final project costs are reported to be exactly identical to the project's initial cost estimate, providing no updates to the actual project costs.

Based on discussions with PJM transmission developers, we understand that updates of initial cost estimates are undertaken by the transmission developers on a voluntary basis. To assume that every project for which the cost estimates have not been updated means that the final project costs are identical to the initial estimates will necessarily understate the measured cost escalations.

Additionally, relying on initial cost estimates that have not been updated is inconsistent with the Concentric authors' statement that initial cost estimates are necessarily high-level and will be refined throughout the project development process. If a project's final cost is exactly equal to its initial cost estimate, we have assumed that there is no information about the final cost of the project.

In addition, we reviewed how often the initial and final costs differ based on the scale of the projects. For larger, more expensive projects (e.g., projects with costs greater than $100 million), 90% of all reported final costs differ from the initial estimates, suggesting that 90% of all projects have updated final cost data. For projects with a cost between $25 million and $100 million, approximately half of all reported final costs differ from the projects' reported initial cost estimates. For projects costing less than $25 million, however, most projects show reported "final" costs that are exactly identical to the initial estimates. This pattern of an increasingly larger portions of small projects without updated final cost data supports our approach of excluding such projects from our analysis.

Overall, we maintain that it is appropriate to exclude transmission projects for which initial cost estimates and final project costs are identical. This is because it is most likely that the cost data in PJM's records have not been updated by the transmission developers and, thus, are not reflective of true final project costs. By including these projects, the Concentric authors assume that many final costs are identical to initial cost estimates and thereby calculate that a large number of projects have cost escalations of zero. This necessarily reduces the average PJM-wide escalation calculated by the Concentric authors. By excluding projects without updated final cost data, our sample also is focused more on larger projects, which are the type of projects that are most suitable for competitive solicitations and thus the most relevant benchmark against which cost savings of competitive processes can be measured.

C. Concentric Understates Cost Escalations of SPP Projects

The Concentric authors reviewed estimated cost escalations for SPP's Balanced Portfolio Projects, Priority Projects, and ITP Portfolio Projects. Similar to the issues we raised with their analysis of MISO costs, we find that Concentric again does not consider the change in costs from the initial cost estimate to the final costs. For the Balanced Portfolio and Priority Projects, Concentric uses an updated cost estimate following a significant increase in costs, while for the ITP Portfolio Projects they use the "current cost estimates" of projects for which final costs are not reported.

For SPP's *Balanced Portfolio* and *Priority Projects*, the Concentric authors recommend that the updated higher cost estimates should be utilized as points of comparison instead of the initial cost estimate. Comparing final project costs to these higher updated cost estimates, one would inevitably conclude that SPP's Balanced Portfolio and Priority Projects did not experience any cost escalations. Since we compared the winning bid of SPP's only competitive project with SPP's initial planning study cost estimate for that project, the initial project cost estimates remain the appropriate point of comparison. In addition, as we show in Table 8 of our report, the bid for the competitive project was 50% below SPP's cost estimate. This difference is large enough so that the extent of whether transmission project costs do not escalate (from the updated estimate) or escalate 18% (from the initial estimate) would not materially change our finding that competitive processes offer significant cost savings.

The Concentric authors noted that SPP's updated higher project cost estimates simply reflect additional costs due to line rerouting and reactive compensation and that these types of cost increases would occur with any transmission project, regardless of its developer or the process by which it is selected. We agree and have noted the justifications for such cost increases in our report. However, since we explicitly assume in our estimate of cost savings that such cost increases (relative to initial cost estimates) could also be incurred by competitive projects (within certain limits allowed in cost control commitments), the fact that such cost escalations are justified does not change our overall conclusions.

For *ITP Portfolio Projects*, SPP provides up to three cost estimates: Baseline Cost Estimate, Current Cost Estimate, and Final Cost. We calculate cost escalation by comparing "Final Cost" to "Baseline Cost Estimate" for all projects for which SPP provides both of these data points. However, as the Concentric authors note, this means we excluded projects for which Final Cost data have not yet been made available by SPP. To expand their sample and include projects without Final Cost data, the Concentric authors rely on SPP's most recent "Current Cost Estimate" in place of a project's Final Cost. A comparison of projects for which both Current Cost Estimates and Final Costs are available shows that SPP's Current Cost Estimates often are substantially below Final Costs. In fact, in some instances, the Current Cost Estimate has not even been updated from the Baseline Cost Estimate. For this reason, and as illustrated in Table 2 below, it is unreasonable to use Current Cost Estimate as a proxy for Final Cost. By doing so, the Concentric authors significantly understate total cost escalations of ITP projects.

Table 2: Examples of Cost Escalations of SPP ITP Projects Based on "Current Cost Estimate" (Concentric) and "Final Cost" (Brattle)

NTC ID, PID, and UID	SPP Baseline Cost Estimate	SPP Current Cost Estimate	SPP Final Cost	Brattle Escalation Estimate	Concentric Escalation Estimate
	[1]	[2]	[3]	[4]=[3]/[1]-1	[5]=[2]/[1]-1
200208_909_50579	$3,000,000	$3,000,000	$3,672,718	22%	0%
200299_30581_50763	$5,693,264	$5,693,264	$7,594,703	33%	0%
200299_30581_50764	$6,929,179	$6,929,179	$7,409,811	7%	0%
20084_834_11101	$6,500,000	$7,588,596	$8,084,263	24%	17%
200166_30356_50407	$7,699,644	$8,287,874	$9,933,961	29%	8%
200309_30717_50883	$13,283,227	$10,291,637	$17,588,398	32%	-23%
200200_30488_50595	$17,928,848	$17,928,848	$19,103,991	7%	0%

D. Concentric's Claimed Lower Cost Escalations of Projects in ISO-NE Do Not Affect Our Estimates of Cost Savings

In page A-1 of their report, the Concentric authors also disagree with our estimate of transmission cost escalations in ISO-NE, noting that we "inappropriately compared final project cost to early planning level estimates." The cost escalations calculated based on subsequent cost estimates, such as inflation-adjusted cost estimates or cost estimates filed in the siting applications, will inevitably be lower than using the initial cost estimates. This is because the updated cost estimates for projects in ISO-NE are substantially above the initial project cost estimates. However, as explained above, we rely on initial project cost estimate as the reference point for both competitive and traditionally developed transmission projects. With respect to ISO-NE, this reference point is irrelevant to our analysis of cost savings from competitive projects since ISO-NE has not conducted competitive transmission solicitation yet and the joint clean energy and transmission solicitations in New England did not involve any transmission cost estimates.

The Concentric authors claim that our sample of ISO-NE projects represent less than 2% of all projects placed in service across ISO-NE since 2002. This percentage is misleadingly however because as shown in Table 19 of our report, our portfolio of ISO-NE projects reflects a total transmission investment of $4.2 billion, which exceeds the $3.8 billion of transmission investments examined by Concentric in Table 2 of their report.

E. Concentric Misrepresents Our Analysis of CAISO Cost Escalation

The Concentric authors' comparison of estimated cost escalations with ours in Figure 1 (page 3) of their report does not include a comparison of cost escalations for California ISO (CAISO) transmission projects. They nevertheless critiqued our analysis of CAISO costs data on pages 12–13 and A-8 through A-10 of their report, noting that our 41% cost escalation estimate of traditionally-developed California transmission projects is based on only 10 projects with CAISO initial cost estimates, rather than the broader set of projects for which data was available. This critique is misplaced for several reasons.

First, because we compare bids for ten CAISO competitive transmission projects with CAISO's initial project cost estimates for those projects, we conducted consistent analyses for traditionally-developed transmission projects by also analyzing how the completed costs of these projects compared to CAISO initial cost estimates. However, CAISO initial cost estimates were available for only ten traditionally-developed projects. Our comparison of ten competitively bid projects with ten traditionally developed projects—with both samples consisting of projects of similar size—showed that the bids of competitive projects on average were 29% below CAISO's initial cost estimate (Table 9), while the final costs of traditionally-developed projects on average had escalated 41% above CAISO's initial cost estimates.

Second, we reported cost escalation of traditionally-developed transmission projects beyond those for which CAISO initial cost estimates were available. This larger group of projects, representing $4 billion in total investment, consisted of all projects that: (a) were subject to CAISO or CPUC approval, and thus representative of the type of projects that could be open for competitive solicitations; and (b) had reported data for both initial cost estimates prepared by the incumbent transmission owners and final project costs. Based on this broader set of eighteen traditionally-developed projects, we documented an average cost escalation of 33% relative to the initial cost estimates that the incumbent transmission owners themselves developed and filed with the CAISO or CPUC.

Finally, the Concentric authors critiqued the 33% cost escalation calculated for our larger $4 billion sample of transmission projects by noting that we included Southern California Edison's (SCE's) Tehachapi renewable generation integration projects, which faced a 31% cost escalation over SCE's $1.8 billion initial cost estimate (see Table 18 in our report). Based on the Concentric authors' view, this project should not have been included in the sample because it is "not representative" of typical cost escalation risks because the project was a complex greenfield project that faced significant and unexpected siting challenges. We disagree with this view. Large greenfield projects such as the Tehachapi project, would be the type of project for which competitive solicitations would likely make a difference. In fact, the Tehachapi project is similar to Alberta's competitively solicited Fort McMurray project, for which the Alberta system operated initially estimated costs of CAD $1.8 billion, but which received a binding bid of CAD $1.4 billion (a 21% or $400 million cost saving) and was completed at a cost of $1.6 billion after allowing cost adjustments for rerouting.[8]

F. The Bottom Line: The Project's Initial Cost Estimates Are the Best Basis for Comparison for Estimated Cost Savings from Competitive Solicitations

In summary, we disagree with the Concentric authors' approach to calculate cost escalations of traditionally developed transmission projects based on updated estimates of project costs or excluding major greenfield projects, such as Tehachapi, from the sample. We applied equivalent treatment to competitive and traditionally developed projects by using initial cost estimates as the starting point for both to evaluate cost escalations and potential savings. The Concentric authors did not. The Concentric authors state that ISO/RTO's initial cost estimates are not the best basis for comparing winning bids against the cost of traditionally developed projects. But those initial cost estimates are the most relevant information for comparisons as these same initial estimates are used for both competitive and traditionally developed projects as their starting points for evaluating project cost trends . The Concentric authors inappropriately compare bids of competitive projects against initial cost estimates while comparing traditionally developed projects against updated cost estimates, which are generally higher due to cost escalations.

This debate over the use of various cost estimates shows that transmission costs are not currently tracked consistently. The lack of well-documented and meaningful cost data is a challenge for transmission customers and policymakers interested in understanding these costs. Thus, we reiterate our recommendation that the reporting and tracking of transmission project cost data be improved and made more transparent across all regions.

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8 See discussion on page 49 of our report.

IV. Overall Conclusion: The Experience with Order No. 1000 Already Supports that Competitive Solicitations of Transmission Projects Should Be Expanded

The Concentric authors conclude on page 38 of their report that there is "no basis to expand the scope of competitive solicitations in FERC-jurisdictional ISOs/RTOs." This conclusion is based in large part on their claims that: (1) it is not yet possible to estimate savings because final costs are not known and cost control commitments may not be effective; (2) traditionally-developed transmission projects do not experience cost escalations; and (3) the significant time requirement of competitive solicitations could lead to costly delays and reliability challenges. However, as we have discussed above, these conclusions are not based on sound analysis of typical cost escalations for traditionally-developed projects. They inappropriately dismiss the effectiveness of cost control commitments, and they exaggerate the time and resource requirements of competitive solicitation processes.

In attempting to support their recommendation that the scope of competitive solicitations should not be expanded because cost control commitments may not be effective, the Concentric authors (on page 18 of their report) cite to a research paper by Professor Paul L. Joskow of the Massachusetts Institute of Technology (M.I.T.).[9] Prof. Joskow's research paper, however, offers the following conclusions that are contrary to the Concentric authors' findings and recommendations:

- "[T]here is quite a bit to learn from the 16 projects selected through an organized competitive procurement process by ISOs since Order 1000 went into effect"
- Non-incumbents' "projects often have significantly lower cost estimates than the incumbent's, often combined with cost containment commitments"
- "The competitive procurements demonstrate that competing transmission developers can reduce expected costs by coming up with innovative designs to resolve transmission needs identified through the ISO regional planning process, taking on more performance risk…etc."
- "Competitive procurement may also induce incumbents and non-incumbents to sharpen their pencils"
- "While the jury is necessarily still out on whether competitive procurement leads to lower costs to meet specific transmission needs, I think that there are good reasons to believe that it likely does. The evidence from other countries…is consistent with this view."
- "**[T]he experience to date is sufficiently promising to consider expanding the use of open competitive procurement solicitations for transmission projects…there are potential efficiency gains from expanding open competitive solicitation opportunities**…." [emphasis added]

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9 "Competition for Electric Transmission Projects in the U.S.: FERC Order 1000," March 16, 2019. Available at: https://economics.mit.edu/files/16832.

We maintain that the analysis we presented in our report provides a reasonable view of the potential cost savings of competitive solicitations and federal and state policy makers should expand the scope of competitive transmission processes.

As shown, competitive processes offer well-documented cost savings by:

- Pressuring competing transmission developers to become more innovative in their project design, engineering, and other development procedures, which offers well-documented cost savings.
- Encouraging transmission developers to engage in advanced design, engineering, and project planning to capture their competitive advantages—and sometimes partnering with parties that are in the best position to bring forth the best project at the lowest costs.
- Providing incentives for finding the most competitive financing structure and costs.
- Creating incentives for planners (at the ISOs/RTOs) to be more accurate in specifying the needs and estimating the potential project costs.