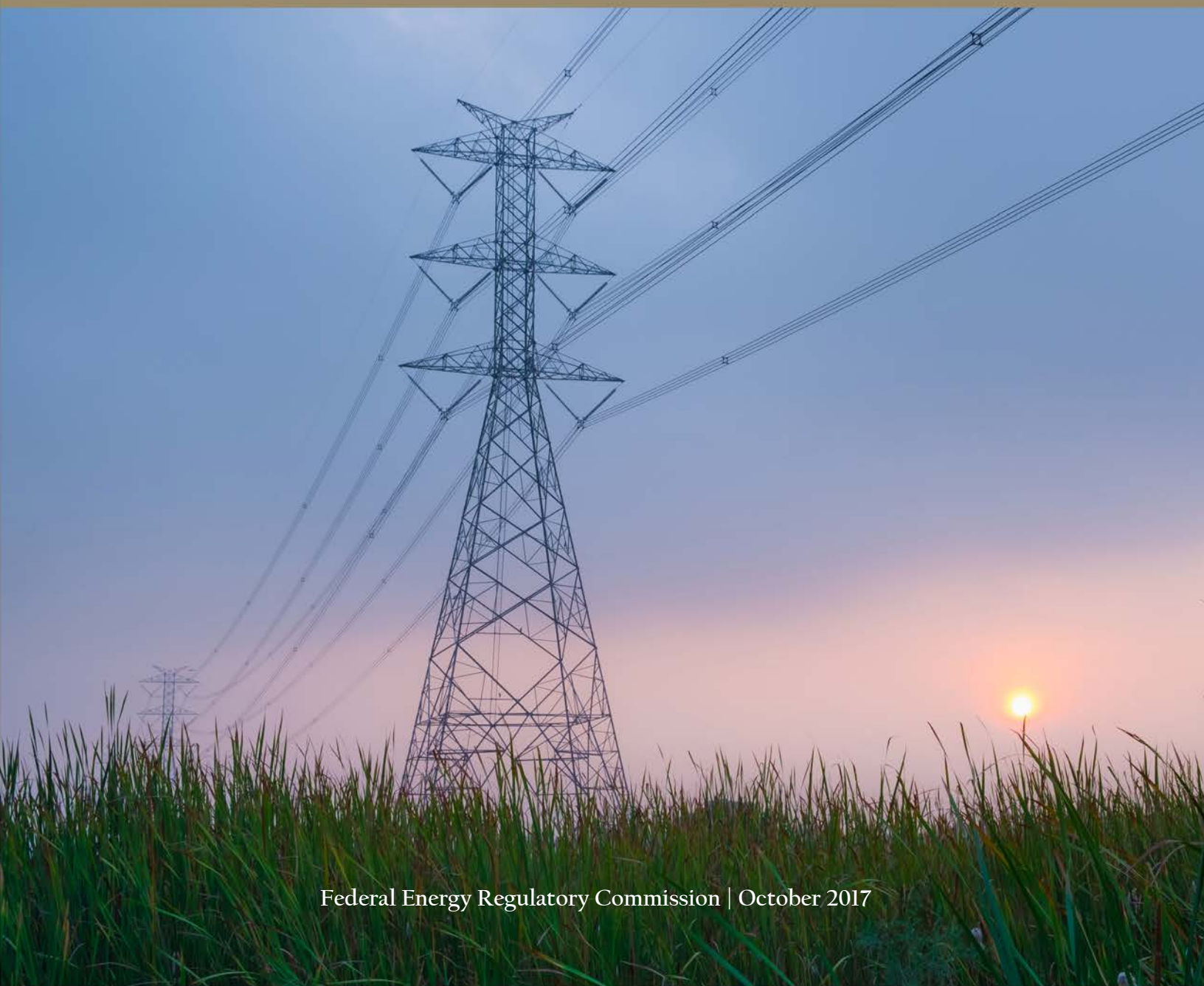




2017 TRANSMISSION METRICS

STAFF REPORT



2017 Transmission Metrics

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Federal Energy Regulatory Commission

October 6, 2017

The opinions and views expressed in this staff report do not necessarily represent those of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission.

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Executive Summary

In 2016, Federal Energy Regulatory Commission (Commission) staff developed several metrics that assessed transmission investment patterns to inform whether additional Commission action would be necessary to facilitate more efficient or cost-effective transmission development in the United States (U.S.) that is sufficient to satisfy the nation's transmission needs. Commission staff published its initial report (2016 Report),¹ with the analysis and findings, in March 2016 and presented the results at the April 2016 Commission meeting.

In this report (2017 Report), staff presents updated results for all but one² of the metrics included in the 2016 Report, as well as initial results for several new metrics. Like the 2016 Report, this iteration explains the data and methods that staff used to calculate each metric. Then, the report presents the results for each metric and staff's inferences based on the calculated metrics. When discussing the metrics to assess the participation of nonincumbent transmission developers in the regional transmission planning processes, the 2017 Report focuses on only those transmission planning regions that have conducted at least one competitive proposal window.³ To date, these include only five transmission planning regions, all of which are RTOs/ISOs. With the exception of the RTO/ISO market price differential metric, all of the other metrics include data from all transmission planning regions.

¹ See *Transmission Metrics: Initial Results*, AD15-12-000, Federal Energy Regulatory Commission (March 2016), <https://www.ferc.gov/legal/staff-reports/2016/03-17-16-report.pdf>.

² The metric on load-weighted curtailment frequency was not included in the 2017 Report, and the reason for this omission is discussed below.

³ For convenience, we use the term proposal window to represent the opportunity that a transmission planning region provides for transmission developers to submit proposals in response to transmission needs or to be selected to use the regional cost allocation method for a specific transmission project.

Key new findings in the 2017 Report include:

Transmission Investment Metrics	
Metric	New Findings in the 2017 Report
Metrics to Assess Participation of Nonincumbent Transmission Developers in Regional Transmission Planning Processes	
Percentage of Nonincumbent ⁴ Transmission Project Bids or Proposals	<ul style="list-style-type: none"> • PJM Interconnection, L.L.C. (PJM) held five new competitive proposal windows in 2015 and 2016, with nonincumbents submitting 46 percent of the proposals received between 2013 and 2016. • For its first two proposal windows, New York Independent System Operator (NYISO) received more proposals from nonincumbents than incumbents in 2015, but the reverse was true in 2016. • Nonincumbents submitted the majority of proposals in response to Midcontinent Independent System Operator’s (MISO) first proposal window in 2016.
Number of Unique Developers ⁵ Submitting Proposals (New Metric for 2017 Report)	<ul style="list-style-type: none"> • The number of unique developers submitting proposals in PJM was comparatively low compared to the total number of proposals received. • In California Independent System Operator (CAISO), NYISO, and MISO, unique developers submitted roughly one proposal each.
Number and Percentage of Selected Nonincumbent Proposals (New Metric for 2017 Report)	<ul style="list-style-type: none"> • For all of the transmission planning regions that had competitive proposal windows, the percentage of selected proposals that nonincumbents submitted declined from 20 percent in 2013, to 6 percent in 2014, to 3 percent in 2015, and to zero in 2016. • CAISO had the largest increase in nonincumbents’ share of selected proposals between 2013 and 2015.

Chart continued next page

⁴ Order No. 1000 defines a “nonincumbent transmission developer” as either: (1) a transmission developer that does not have a retail distribution service territory or footprint; or (2) a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the incumbent for purposes of that project. By contrast, an “incumbent transmission developer/provider” is defined as an entity that develops a transmission project within its own retail distribution service territory or footprint. *See* Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 225 (2011), order on reh’g, Order No. 1000-A, 139 FERC ¶ 61,132, order on reh’g and clarification, 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).

⁵ A unique developer is defined as an entity that is distinct from other transmission developers in terms of the proposals submitted to a transmission planning region in a given year. In instances where a transmission developer submits multiple proposals in a given year, staff considers that transmission developer only once for that year. A unique developer can include an incumbent transmission developer, a nonincumbent transmission developer, a consortium (where a group of transmission developers operates as a separate legal entity), or a joint venture where two or more legal entities (either incumbent or nonincumbent) work together to develop a proposal while maintaining their own legal status. Furthermore, a given transmission developer that submits proposals independently is considered distinct from a consortium or joint venture in which that entity is involved. The purpose of this metric is to determine how many distinct developers are submitting proposals (i.e., Are a few transmission developers submitting most of the proposals in a given transmission planning region or are many different transmission developers submitting proposals?).

	<ul style="list-style-type: none"> • PJM selected the largest number of proposals overall compared to other transmission planning regions, but it selected only one nonincumbent proposal over four years. • Southwest Power Pool (SPP) and MISO each selected an incumbent proposal in their single proposal windows in 2015 and 2016, respectively.
Stakeholder Participation in Regional Transmission Planning Processes (New Metric for 2017 Report)	<p>Stakeholder attendance at regional transmission planning process meetings during fiscal year 2015 (FY 2015) and fiscal year 2016 (FY 2016) was relatively stable in both RTOs and non-RTOs.</p> <p>Nonincumbents are participating in stakeholder meetings in most transmission planning regions, with their participation increasing in four of the 12 regions.</p>
Metric to Indicate Whether Appropriate Levels of Transmission Infrastructure Exist	
RTO/ISO Market Price Differential	Relatively high or low real-time locational marginal prices (LMPs) occurred persistently (i.e., for at least two years) at 1,482 generator or load points since 2005, a decline from 1,986 points in the 2016 Report. Many of the high-priced points and low-priced points disappeared in SPP.
Metrics to Permit Baseline Analyses of the Impacts of Policy Changes	
Load-weighted Transmission Investment (Incremental)	Load-weighted transmission investment averaged \$2.43 per megawatt hour (MWh) of retail load for all North American Electric Reliability Corporation (NERC) regions between 2008 and 2015, up from a load weighted average of \$2.19 per MWh of retail load between 2008 and 2014 in the 2016 Report.
Load-weighted Circuit-Miles (Incremental)	Load-weighted circuit-miles remained unchanged from the 2016 Report at 1.9 circuit-miles per terawatt hour (TWh) across all NERC regions between 2008 and 2015.
Load-Weighted Circuit-Miles per Million Dollars of Investment (Incremental) ⁶	<p>The average load-weighted circuit-miles per million dollars of investment decreased slightly between the 2016 Report and the 2017 Report by 0.1 load-weighted circuit-miles per million dollars of transmission investment for all NERC regions.</p> <p>Midwest Reliability Organization (MRO) fell from the NERC region with the highest load-weighted circuit-miles per million dollars of investment in the 2016 Report to the region with the sixth highest load-weighted circuit-miles per million dollars of investment in the 2017 Report.</p>

⁶ The metric addressing load-weighted circuit-miles per million dollars of investment (incremental) aims to provide a basis for assessing the cost impact of different policy choices or factual circumstances on transmission investment. Weighting the transmission circuit miles by million dollars of investment in each NERC region allows for comparison between regions of different sizes.

Introduction

The Commission has long had the goal of ensuring that its policies help achieve appropriate levels of transmission investment to address current and emerging reliability needs, economic considerations, and transmission needs driven by public policy requirements while maintaining just and reasonable rates, as required under the Federal Power Act. Most recently, the Commission reformed its policies regarding transmission planning and cost allocation in Order No. 1000, through which it sought to promote more efficient or cost-effective transmission development by requiring each public utility to, among other things, (1) participate in regional transmission planning processes, (2) provide opportunities for nonincumbent transmission developers to propose and develop regional transmission facilities through competitive transmission development processes,⁷ and (3) establish a regional cost allocation method to allocate the costs of transmission facilities selected in the regional transmission plan for purposes of cost allocation (i.e., regional transmission facilities).

As noted in the 2016 Report, it is difficult to assess whether the electric industry is investing in sufficient transmission infrastructure to meet the nation's needs and whether the investments made are more efficient or cost-effective.⁸ Nevertheless, staff has attempted to develop a range of objective and standardized measures of various characteristics of the electric system and its performance to help assess the effectiveness of the Commission's policies in achieving its goals regarding transmission investment and to inform potential policy revisions going forward. As in the 2016 Report, the metrics in this report fall into three broad categories: (1) metrics designed to evaluate key goals of Order No. 1000; (2) metrics designed to indicate whether appropriate levels of transmission infrastructure exist in a particular region; and (3) metrics designed to permit analysis of the impact of Commission policy changes by comparing key values before and after changes take place.

When preparing the 2017 Report, staff considered whether additional metrics could further help staff to assess the effectiveness of the Commission's policies and better inform potential policy revisions going forward. As a result of its analysis, staff identified three additional metrics: (1) number of unique developers submitting proposals; (2) number and percentage of selected nonincumbent proposals; and (3) stakeholder participation in regional transmission planning

⁷ We refer to the process to select transmission facilities in the regional transmission plan for purposes of cost allocation and the process to provide a transmission developer of a selected transmission facility with eligibility to use the regional cost allocation method collectively as the competitive transmission development process. See Supplemental Notice of Technical Conference and Request for Speakers, Docket No. AD16-18-000, at 8-9 (May 10, 2016).

⁸ Potential reasons for this difficulty include, but may not be limited to:

- ***Stakeholders cannot agree on what would constitute an appropriate amount of transmission investment.*** For example, some stakeholders may prefer a system that prioritizes public policy concerns, while others may prefer a system that prioritizes reliability. Similarly, some may expect strong load growth or the development of distributed generation, while others may not.
- ***There are alternatives to transmission in some circumstances.*** Some transmission issues can be addressed using alternatives to transmission investments, such as generation or demand-side resources, while other issues can only be addressed with transmission investment.

processes. A unique developer is defined as an entity that is distinct from other transmission developers in terms of the proposals submitted to a transmission planning region in a given year. In instances where a transmission developer submits multiple proposals in a given year, staff considers that transmission developer only once for that year. A unique developer can include an incumbent transmission developer; a nonincumbent transmission developer; a consortium (where a group of transmission developers operates as a separate legal entity), or a joint venture where two or more legal entities (either incumbent or nonincumbent) work together to develop a proposal while maintaining their own legal status. Furthermore, a given transmission developer that submits proposals independently is considered distinct from a consortium or joint venture in which that entity is involved. Staff concludes that these three new metrics will help the Commission to evaluate progress in achieving the key goals of Order No. 1000, as they assess the level of competition in transmission development processes by measuring nonincumbent participation, as well as stakeholder engagement in these processes.

Staff also notes the exclusion of the load-weighted curtailment frequency metric, under the second broad category of metrics, from the 2017 Report. Staff initially hoped to use the metric to gauge congestion in areas outside of organized wholesale electric markets. However, upon further analysis, staff found that the caveats associated with the metric calculation, as detailed in the 2016 Report,⁹ significantly limited the insights that it could provide. In particular, the metric applied only to the Eastern Interconnection and served to identify congestion between two organized wholesale electric markets or between organized wholesale electric markets and neighboring regions rather than identifying congestion within regions outside of the organized wholesale electric markets. Staff continues to consider other metrics to include in future reports that could better assess congestion outside of organized wholesale electric markets.

Below, staff describes the methodology for calculating each of the three categories of metrics, the results of staff's analyses, and the further research that staff believes is needed to help ensure that each metric provides useful insight as to whether transmission investment in the U.S. is both more efficient or cost-effective and yields sufficient transmission infrastructure to meet future reliability needs, economic considerations, and transmission needs driven by public policy requirements.

⁹ See *Transmission Metrics: Initial Results*, AD15-12-000, Federal Energy Regulatory Commission (March 2016), <https://www.ferc.gov/legal/staff-reports/2016/03-17-16-report.pdf>.

I. Metrics to Assess Participation of Nonincumbent Transmission Developers in Regional Transmission Planning Processes

Transmission planning regions have adopted one of two types of competitive transmission development processes to comply with Order No. 1000's requirements: a competitive bidding model or a sponsorship model.¹⁰ Under the competitive bidding model, the transmission planning region, with stakeholder input, 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 (both incumbent and nonincumbent) for the transmission solutions it selected that are eligible for the competitive bidding process. The transmission planning region chooses from among the developers and designates a winning transmission developer as eligible to use the regional cost allocation method to develop the selected transmission project. Relevant to this report, CAISO, MISO, and SPP have adopted this model.

Under a sponsorship model, the transmission planning region, with stakeholder input, identifies regional transmission needs. Then, qualified transmission developers (both incumbent and nonincumbent) may propose transmission projects to meet those identified regional transmission needs. The transmission planning regions selects the more efficient or cost-effective 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. If a transmission planning region selects a transmission solution that was sponsored by a transmission developer, then the sponsor is eligible to use the regional cost allocation method to develop the selected transmission project. Relevant to this report, NYISO and PJM have adopted this model, although PJM's process includes aspects of a competitive bidding model in certain situations.

Given that Order No. 1000 requires that both incumbent and nonincumbent transmission developers have the same eligibility to use the regional cost allocation method for selected transmission projects,¹¹ one question that arises is the success of nonincumbent proposals under both competitive bidding models and sponsorship models following the implementation of Order No. 1000. There are several ways in which competition between incumbents and nonincumbents in competitive transmission development processes can be gauged. This section of the report describes staff's analysis of three measures to assess competition at the transmission planning region level: (1) the percentage of proposals submitted by incumbents

¹⁰ A transmission planning region is made up of the transmission providers that have enrolled in the region, and depending on what processes have been adopted, it may be a transmission planning region or the transmission providers within that region that administer the competitive transmission development process. For convenience, we refer to the transmission planning region and transmission providers enrolled in the region collectively as the transmission planning region.

¹¹ Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at PP 332, 339.

and nonincumbents in a given year, (2) the number of unique developers submitting proposals in a given year and their share of the total proposals submitted, and (3) the number and share of proposals selected that were nonincumbent proposals. In addition, staff reports its evaluation of stakeholder involvement in regional transmission planning processes, another measure of engagement in competitive transmission development processes.

As discussed further below, staff notes that a significant number of joint ventures and consortia submitted proposals through the competitive proposal windows that were opened during the period that staff studied in this report. Many of these joint ventures and consortia included nonincumbent transmission developers along with incumbent transmission developers from the regions in question. In Order No. 1000, the Commission adopted its nonincumbent transmission developer-related requirements to eliminate practices that have the potential to undermine the identification and evaluation of more efficient or cost-effective alternatives to regional transmission needs, thus helping to ensure just and reasonable rates for transmission customers.¹² Nonincumbent transmission developers aid this effort by bringing novel viewpoints and innovative ideas to the transmission planning process as well as serving as entities with which incumbents must compete to be selected as the developer of a given project, and this may be true whether they remain independent or enter into joint ventures or consortia with incumbent transmission developers. The act of competing and facing competition also helps ensure just and reasonable rates. While joint ventures and consortia may bring substantial benefits, when nonincumbent transmission developers enter into joint ventures or consortia with incumbent transmission developers, it may reduce the total number of competitors and ideas presented in the competitive transmission development process, potentially reducing some of the benefits from having nonincumbent transmission developers participate. Staff plans to explore these developments further in future transmission metrics reports.

PERCENTAGE OF NONINCUMBENT TRANSMISSION PROJECT BIDS OR PROPOSALS

Background

This metric measures the percentage of proposals that nonincumbent transmission developers submitted in competitive transmission development processes. For the purpose of this report and to be consistent with Order No. 1000, staff includes as nonincumbents any new consortium or joint venture as long as the project is located outside of all of the associated entities' retail distribution service territories or footprints.¹³ Staff notes that this metric addresses only regional

¹² Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 226.

¹³ A consortium or joint venture may include incumbents, nonincumbents, or some combination of the two. If the consortium or joint venture is made up of all nonincumbents, then staff considers the consortium or joint venture to be a nonincumbent. If the consortium or joint venture includes an incumbent and a nonincumbent, the project must be located outside of the incumbent's retail distribution service territory or footprint in order for the

transmission projects; it does not reflect projects proposed outside of the regional transmission planning process or any interregional transmission projects. This metric is intended to measure nonincumbent participation in regional transmission planning processes, which the Commission concluded in Order No. 1000 was necessary in order to eliminate practices that have the potential to undermine the identification and evaluation of more efficient or cost-effective alternatives to regional transmission needs, thus helping to ensure just and reasonable rates for transmission customers.¹⁴

Methodology

Staff gathered data on the proposals that developers submitted in the proposal windows held under the competitive transmission development processes in CAISO, PJM, NYISO, MISO, and SPP, the five transmission planning regions that have held competitive transmission development processes since the implementation of Order No. 1000. In the future, it should be possible to perform a similar analysis for other regional transmission planning regions when they start holding their own competitive transmission development processes.

To calculate this metric, staff gathered data from public documents posted on the websites of CAISO, PJM, NYISO, SPP, and MISO. For CAISO, proposal data came from documents submitted during Phase 3 (the project sponsor selection phase) of the 2012-2013 and 2013-2014 transmission planning processes, under which CAISO opened nine proposal windows from 2013 to 2015.¹⁵ CAISO has not had any additional proposal windows since publication of the 2016 Report. However, the values and percentages for CAISO that are presented in the 2017 Report are slightly different due to the reclassification of certain developers.¹⁶

For PJM, staff gathered information on numerous proposals from PJM's Regional Transmission Expansion Planning (RTEP) Proposal website¹⁷ and from documents posted by the Transmission Expansion Advisory Committee (TEAC).¹⁸ PJM opened 14 proposal windows

consortium or joint venture to be considered a nonincumbent. If the consortium or joint venture is made up of all incumbents, then the project must be outside of all of the incumbents' retail distribution service territories or footprints in order for it to be classified as a nonincumbent. For the purpose of this analysis, a consortium represents a combination of transmission developers (either incumbents or nonincumbents) that operate under a different firm name and is usually a distinct legal entity. A joint venture, on the other hand, indicates two or more transmission developers that choose to work together and submit a single proposal while still maintaining their own separate businesses.

¹⁴ Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 226.

¹⁵ See <http://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx> and <http://www.caiso.com/planning/Pages/TransmissionPlanning/2013-2014TransmissionPlanningProcess.aspx>.

With regard to Order No. 1000 compliance, the Commission approved CAISO's request for an effective date of October 1, 2013, for its filing to allow the compliance tariff provisions to be applied to the 2013-2014 transmission planning cycle rather than the 2012-2013 cycle, which was almost complete when CAISO submitted its compliance filing. See *Cal. Indep. Sys. Operator Corp.*, 143 FERC ¶ 61,057 at P 28 (2013).

¹⁶ Specifically, a few developers that were originally considered to be separate entities in the 2016 Report are now identified as joint ventures since the developers subsequently submitted joint proposals.

¹⁷ See <http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows.aspx>.

¹⁸ See <http://pjm.com/committees-and-groups/committees/teac.aspx>.

between 2013 and 2016; however, staff's analysis of nonincumbents' share of proposals submitted only includes data from the 13 proposal windows for which information was available at the time of staff's analysis. New in the 2017 Report, staff analyzes data from four of the five additional proposal windows that PJM has opened since publication of the 2016 Report. Staff omitted data from the sixth additional proposal window (the 2016/2017 RTEP Long Term Proposal window) because PJM had not yet posted the proposals received on its website as of the preparation of this report.

In addition, NYISO, SPP, and MISO opened their first proposal windows after the publication of the 2016 Report. Staff includes data on these proposal windows for the first time in its analysis in the 2017 Report. Specifically, NYISO has held its first two proposal windows as part of its Public Policy Transmission Planning Process. NYISO's first proposal window, which opened in late 2015, focused on relieving transmission congestion in Western New York State (i.e., the region surrounding Buffalo).¹⁹ In 2016, NYISO's second proposal window specified two different AC transmission projects that affected different sections of the NYISO system.²⁰ Developers were permitted to address one or both segments in their proposals.²¹ Staff used information regarding NYISO's proposal windows from final²² and draft²³ reports on the assessment and selection processes.

SPP held one proposal window in 2015 for the North Liberal-Walkemeyer 115 kV line. While SPP selected a proposal, the transmission planning region cancelled the project in July 2016 due to declining load.²⁴ Nonetheless, staff includes data from SPP's proposal window in its analysis

¹⁹ See

http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Public_Policy_Documents/Western_NY/NYISO_WesternNY_PPTN_VSA_2016-05-31.pdf at 7.

²⁰ Segment A included the Edic or Marcy to New Scotland 345 kV line; two Princetown to Rotterdam 345 kV or 230 kV transmission lines; decommissioning two 230 kV lines from Edic to Rotterdam; and associated switching or substation work at Edic or Marcy, Princetown, Rotterdam, and New Scotland. Segment B entails a new double circuit 345 kV/115 kV line from Knickerbocker to Churchtown; a new double circuit 345 kV/115 kV line or triple circuit 345 kV/115 kV/115 kV line from Churchtown to Pleasant Valley; decommissioning of a double-circuit 115 kV line from Knickerbocker to Churchtown; decommissioning of one or two double-circuit 115 kV lines from Knickerbocker to Pleasant Valley; construction of a new tap of the New Scotland-Alps 345 kV line and new Knickerbocker switching station; and related switching or substation work at Greenbush, Knickerbocker, Churchtown and Pleasant Valley substations. In addition, Segment B requires a new double-circuit 138 kV line from Shoemaker to Sugarloaf; decommissioning of a double-circuit 69 kV line; related switching or substation work at Shoemaker, Hartley, South Goshen, Chester, and Sugarloaf; and upgrades to the Rock Tavern substation.

²¹ See http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2016-09-26/NYISO_AC_Transmission_PPTN_VSA_Draft_Report.pdf at 12.

²² See

http://www.nyiso.com/public/webdocs/markets_operations/documents/Legal_and_Regulatory/NY_PSC_Filings/2016-6-1%20NYISO%20filing%2014-E-0454%20VS%20Assmnt%20Western%20NY%20PPTN.pdf. NYISO submitted these reports to the New York Public Service Commission for review.

²³ See http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2016-09-26/NYISO_AC_Transmission_PPTN_VSA_Draft_Report.pdf.

²⁴ See <https://www.spp.org/documents/40383/mopc%20report%20to%20bod%2007-25-16%20-%20v1-3.pdf> at 53-58.

from the initial request for proposals²⁵ and the final selection report.²⁶ Due to SPP’s reporting practices, staff found it difficult to analyze developers’ incumbency status and the number of submissions per developer. That is, SPP announced only the winner and runner up in its competitive transmission development process.

MISO opened its first proposal window, which was for the Duff-Coleman extra-high-voltage 345 kV line, in 2016 after the completion of its 2015 MISO Expansion Transmission Plan (MTEP). Staff gathered information regarding the project from MISO’s request for proposals on its website.²⁷ MISO selected a proposal in late 2016.²⁸

To determine the incumbency status of developers that submitted proposals, staff applied the Order No. 1000 definition of “nonincumbent” and compared the transmission zone in which each proposed project would be located to the developer’s retail distribution service territory or footprint, where applicable.²⁹ Staff found this step necessary because publicly-available data regarding proposals generally do not state a particular developer’s incumbency status; they merely list the names of the entities that submitted proposals. Since incumbent transmission owners frequently create subsidiaries, sometimes with unique names, for the sole purpose of submitting proposals in one or more particular transmission planning region, staff researched the names and footprints of the parent organizations. Despite the lack of explicit information about incumbency status in the proposals themselves, staff identified the incumbency status of the developers with a high degree of confidence. Joint ventures and consortia as a whole are categorized as incumbents if the projects they propose are located in one or more of the participating transmission developers’ footprints or retail distribution service territories.

As discussed further in the Results and Analysis section, for purposes of comparison, staff grouped proposals by transmission planning region and year in which the proposal window was opened.

²⁵ See https://www.spp.org/documents/28843/spp-rfp-000001_website%20watermarked%20posting%20version_regdateupdate080315.pdf.

²⁶ See https://www.spp.org/documents/37708/iep%20recommendation%20report%20with%20process%20and%20appendix%20public%20redacted%20041216_redacted.pdf.

²⁷ See <https://www.misoenergy.org/Planning/Pages/TransDevQualSel.aspx>.

²⁸ See https://www.misoenergy.org/Library/Repository/Study/Transmission%20Developer/20161220_FINAL_Selection%20Report_SRPT_v1.pdf.

²⁹ Refer to footnotes 3 and 10 for definitions of “nonincumbent” in the context of the 2017 Report.

Results and Analysis

Figure 1 summarizes the results of staff's analysis of the proposals that developers submitted in the proposal windows from 2013 through 2016 in CAISO, MISO, NYISO, PJM, and SPP (with the exception of PJM's 2016/2017 RTEP Long Term Proposal window). For the purpose of this metric, staff analyzed the number of proposals in each window and the incumbency status of the entities submitting the proposals. Staff did not gather data on or analyze the costs associated with the proposals.

Specifically, Figure 1 shows the percentages of proposals submitted by incumbents and nonincumbents annually to each transmission planning region. The chart also notes the total number of proposals received in each region and year.³⁰ Across all five transmission planning regions that have held proposal windows, developers submitted a total of 703 proposals.³¹ Staff found that between 2013 and 2016, incumbents and nonincumbents submitted 52 percent and 47 percent of proposals, respectively. Staff could not classify the remaining one percent of proposals as submitted by incumbents or nonincumbents.

For CAISO, proposals from nonincumbents accounted for two-thirds to three-quarters of all proposals submitted in each of the three years it conducted proposal windows. The percentage of nonincumbent proposals in CAISO are based on nine proposals from seven unique developers in 2013, 19 proposals from nine unique developers in 2014, and three proposals from three unique developers in 2015.³² Overall, there were 31 proposals from 18 unique developers over the three years.³³

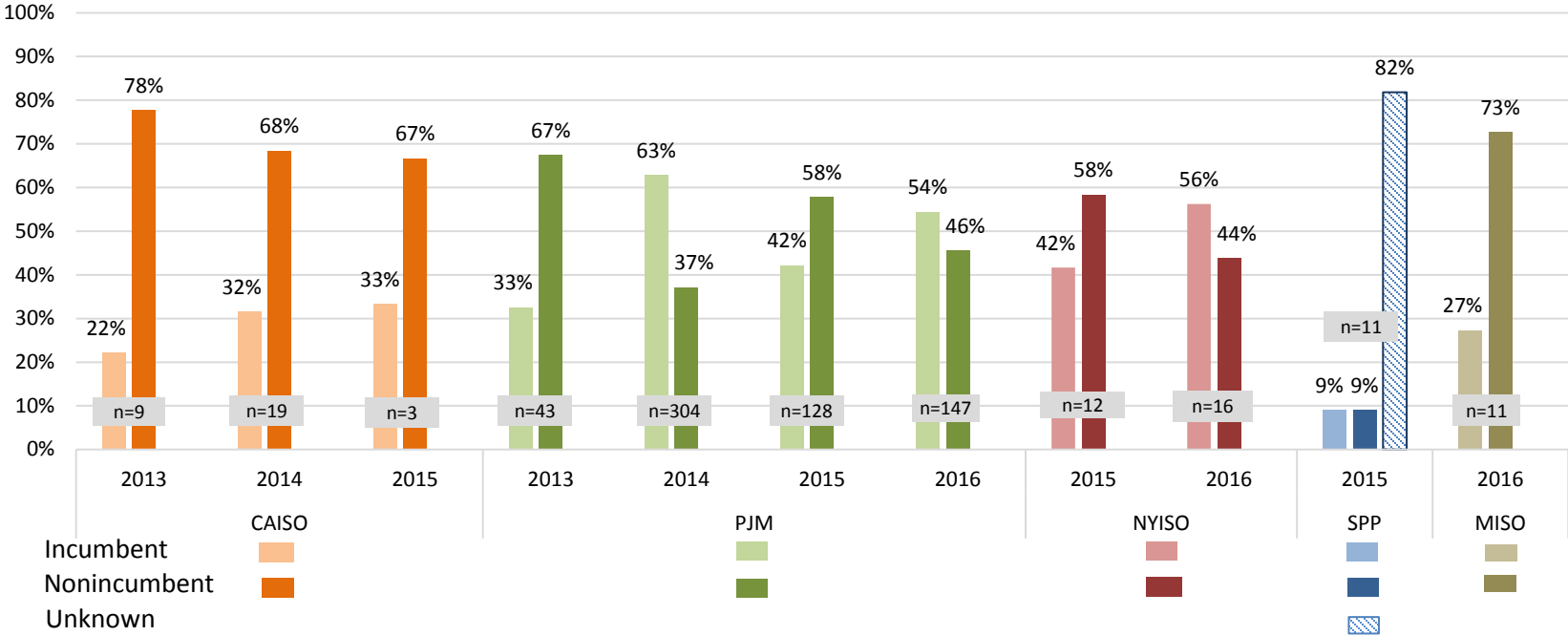
³⁰ Staff assigned proposals to a given calendar year based on the opening and closing dates of the associated proposal window, not the regional transmission planning cycle.

³¹ NYISO disqualified three proposals when those developers did not provide additional information upon request. Staff did not include these three proposals in the total number of proposals submitted.

³² Staff revised the number of proposals and developers in CAISO for the years 2014 and 2015. In *Transmission Metrics: Initial Results*, staff initially reported 20 proposals and 10 developers in 2014 and four proposals and four developers in 2015. A review of CAISO's public notices regarding the proposals received revealed that in both years, two developers independently submitted proposals but then decided to work together and subsequently filed joint proposals. Specifically, in 2014, TransCanyon and SoCal Edison submitted individual proposals. See <http://www.caiso.com/Documents/List-QualifiedProjectSponsors-Proposals-Delaney-ColoradoRiverProject.pdf>. In 2015, NEET West and SoCal Edison each submitted a proposal. See <http://www.caiso.com/Documents/UpdatedListofValidatedProjectSponsorApplications-HarryAllen-EldoradoProject.pdf>. Initially, staff categorized TransCanyon and NEET West as nonincumbents while designating SoCal Edison as an incumbent. Considering the joint proposals, staff now categorizes the joint proposals as incumbents because the projects were located within SoCal Edison's retail distribution service territory.

³³ Because certain entities changed their individual proposals to joint proposals, the newly classified combined developers matched developers in other years, thus causing the number of unique developers to decline.

Figure 1
Competitive Proposals by Incumbents vs. Nonincumbents
 Percentage of annual proposals in CAISO, PJM, NYISO, SPP, and MISO (2013-2016)



Sources: CAISO's 2012-2013 and 2013-2014 transmission plans; PJM's Transmission Expansion Advisory Committee and RTEP proposal websites; NYISO's transmission planning needs reports; SPP's Integrated Transmission Planning 10-Year Study (ITP10), meeting minutes from the Board of Directors/Members Committee, and recommendation report from an industry expert panel; and MISO's Competitive Transmission Administration website.

Seven developers (submitting a total of eight proposals) were unique joint ventures or consortia. Staff classified three of these joint ventures and consortia as incumbents³⁴ based on the location of the projects, while staff classified the other four as nonincumbents.³⁵

In PJM, proposals from nonincumbents made up at least 50 percent of all proposals in 2013 and 2015, but fell to 37 percent in 2014 and 46 percent in 2016. The results for the year 2015 in the 2017 Report vary from those in the 2016 Report due to the inclusion of data from the 2015 RTEP 2 proposal window, which added 23 additional proposals to that year's count. Data from the 2015 RTEP 2 proposal window was unavailable when staff conducted its analysis for the 2016 Report. Moreover, the 2017 Report includes new proposal information for 2016, specifically proposals from the 2016 RTEP 1, 2016 RTEP 2, 2016 RTEP 3, and 2016 RTEP 3 Addendum proposal windows. In total, PJM received 622 proposals between 2013 and 2016, not including those from the 2016/17 RTEP Long Term Proposal window.³⁶ In 2013, 10 unique developers submitted 43 proposals, with three entities being joint ventures (Duke-ATC, Pepco Holdings, Inc. (Pepco)/Exelon Corporation (Exelon),³⁷ and Transource Energy). PJM received nearly half of its total proposal count in 2014. That year, the 2014 RTEP 1 window garnered 106 proposals from 13 developers,³⁸ the 2014 RTEP 2 window comprised of 79 proposals from 13 developers,³⁹

³⁴ The joint ventures and consortia are TransCanyon DCR, LLC (TransCanyon DCR)/Southern California Edison Company (SoCal Edison), NextEra Energy Transmission West, LLC (NEET West)/SoCal Edison, and Pacific Gas and Electric Company (PG&E)/MidAmerican Transmission, LLC (MidAmerican Transmission). TransCanyon DCR is a joint venture between Bright Canyon Energy Corporation, a subsidiary of Pinnacle West Capital Corporation, which is the parent company of Arizona Public Service Company, and BHE U.S. Transmission, a subsidiary of Berkshire Hathaway Energy Company, which is the parent company of PacifiCorp, NV Energy, Inc., and MidAmerican Energy Company.

³⁵ The joint ventures and consortia are (DCR Transmission, LLC (DCR Transmission), Duke-American Transmission Company (Duke-ATC), Golden State Transmission, LLC (Golden State Transmission), and Pattern Energy Group LP (Pattern Development)/City of Pittsburg, California. DCR Transmission is a joint venture between Abengoa Transmission & Infrastructure, LLC, (ATI) and DCR Investor, LLC, an affiliate of Starwood Energy Group Global, LLC. ATI is a wholly-owned subsidiary of Abengoa, South America. Golden State Transmission is a joint venture between Edison Transmission, LLC, and Transource Energy, LLC (Transource Energy); it was not noted as joint venture in the 2016 Report.

³⁶ As explained above, staff did not include proposals from the 2016/17 RTEP Long Term Proposal window because PJM had not yet posted the proposals from that competitive proposal window on its website at the time of staff's analysis.

³⁷ The merger between Exelon and Pepco Holdings did not close until March 2016.

³⁸ Staff reduced this number from 15 developers as described in the 2016 Report as Exelon is the parent company of Baltimore Gas and Electric Company, Commonwealth Edison Company, and Philadelphia Electric Company. Staff misclassified certain proposals in the 2016 Report because it did not account for this corporate relationship and has corrected the data in the 2017 Report.

³⁹ Staff reduced this number from 14 developers as described in the 2016 Report as Exelon is the parent company of Commonwealth Edison Company and Philadelphia Electric Company.

and the 2014/15 Long Term RTEP window accounted for 119 proposals from 19 developers,⁴⁰ for a total of 304 proposals from 22 unique developers.⁴¹

Of this total, six unique joint ventures or consortia submitted 43 proposals (11 from nonincumbents and 32 from incumbents). Transource Energy—a joint venture between American Electric Power Company, Inc. (AEP) and Great Plains Energy Incorporated, formed to pursue new competitive transmission projects—submitted 17 proposals. Of these 17 proposals, staff classified the joint venture as a nonincumbent for nine proposals and as an incumbent for eight proposals given the location of each proposed project. Of the remaining proposals from joint ventures or consortia, Pepco/Exelon submitted 11 proposals, Dominion Resources, Inc. (Dominion)/Transource Energy submitted seven proposals, Dominion/First Energy Corporation (First Energy) submitted four proposals, Duke-ATC submitted three proposals, and PPL Electric Utilities Corporation (PPL Electric Utilities)/First Energy submitted one proposal; staff determined that these developers were incumbents for all of their proposals.⁴²

In 2015, PJM received 128 proposals from 11 unique developers, covering four proposal windows: 2014 RTEP Addendum, 2014 RTEP Addendum 2, 2015 RTEP 1, and 2015 RTEP 2. While the results for that calendar year cover two different transmission planning cycles, nearly all of the proposals (114 out of 128) were submitted for the 2015 RTEP process. During calendar year 2015, staff identified three entities as joint ventures (AEP/Duke Energy Corporation (Duke Energy), PPL Electric Utilities/First Energy, and Transource Energy). Transource Energy was an incumbent for 2 of its 11 proposals. AEP/Duke Energy submitted one proposal, and PPL Electric Utilities/First Energy submitted two proposals, all as incumbents. In total, the joint ventures submitted 14 proposals.

This report also captures proposal information from PJM's first four proposal windows in 2016. In total, PJM received 147 proposals from 15 unique developers, including one joint venture (AEP/Duke Energy) and one consortium (Transource Energy). AEP/Duke Energy submitted one proposal, and Transource Energy submitted 15 proposals. Staff identified Transource Energy as an incumbent for half of its proposals. By proposal window, PJM received 25 proposals in 2016 RTEP 1, 87 proposals in 2016 RTEP 2, 29 proposals in 2016 RTEP 3, and 6 proposals in 2016 RTEP 3 Addendum.

In NYISO, nonincumbent proposals accounted for 58 percent and 44 percent of proposals received in 2015 and 2016, respectively. Most developers submitted multiple proposals. In 2015, NYISO received a total of 15 proposals (12 Public Policy Transmission Projects and 3 Other

⁴⁰ Staff reduced this from 22 developers as described in the 2016 Report as Exelon is the parent company of Baltimore Gas and Electric Company, Commonwealth Edison Company, and Philadelphia Electric Company. In addition, staff categorized Dominion High Voltage Transmission/Transource Energy the same as Dominion/Transource Energy.

⁴¹ Staff reduced this from 30 developers in the 2016 Report to reflect the reclassifications described in the preceding footnotes.

⁴² Staff revised the 2014 information from the 2016 Report to reflect that PJM ran proposal windows for the 2014 RTEP in 2015. PJM opened the 2014 RTEP 2 Addendum proposal period from January, 20, 2015, to February 6, 2015, and the 2014 RTEP Addendum 2 window from February 24, 2015, to March 12, 2015. In the 2017 Report, staff includes proposals from these two proposal windows in the 2015 results for PJM rather than the 2014 results.

Public Policy Projects), but it disqualified three proposals because the developers did not provide supporting information upon request.⁴³ The remaining 12 proposals (11 Public Policy Transmission Projects and 1 Other Public Policy Project) were submitted by seven unique developers, where three were incumbents and four were nonincumbents. One of the developers, an incumbent, was a joint venture (New York Power Authority/New York State Electric and Gas Corporation).⁴⁴ After review, NYISO determined that 10 proposals were viable.⁴⁵ In 2016, NYISO received 16 proposals (15 Public Policy Transmission Projects and 1 Other Public Policy Projects) from six unique developers, with 13 proposals identified as viable by NYISO.⁴⁶ For these proposals, staff identified three incumbents and three nonincumbents, where one joint venture (North America Transmission⁴⁷/New York Power Authority) was an incumbent for one proposal and a nonincumbent for another based on the project's location. In addition, one consortium (National Grid/New York Transco) submitted proposals as an incumbent. After reviewing the proposals, NYISO found that 13 proposals were viable.

As stated above, SPP has had one competitive proposal window – its first – which occurred in 2015. In response, SPP received 11 proposals. As reported in a news release,⁴⁸ SPP selected the Mid-Kansas Electric Company, a consortium of electric cooperatives, as the winning developer.⁴⁹ Staff considers Mid-Kansas Electric Company an incumbent due to the location of the project relative to the service area of one of the member cooperatives. Oklahoma Gas and Electric Company, which staff determined to be a nonincumbent, was reported as the runner up. Figure 1 indicates the incumbency status of the nine anonymous proposals as unknown.

Similar to SPP, MISO recently conducted its first proposal window in 2016. Overall, 11 unique developers each submitted a single proposal. Nonincumbent proposals accounted for 73 percent of the submissions. Five unique joint ventures or consortia submitted one proposal each. Staff classified three of these joint ventures and consortia (Duke-ATC; Republic Transmission, LLC (Republic Transmission));⁵⁰ and Southern Indiana Gas and Electric Company doing business as Vectren Energy Delivery of Indiana, Inc./Public Service Enterprise Group Incorporated (PSEG))

⁴³ NYISO did not disclose the identities of the developers associated with the disqualified proposals.

⁴⁴ See

http://www.nyiso.com/public/webdocs/markets_operations/documents/Legal_and_Regulatory/NY_PSC_Filings/2016/2016-6-1%20NYISO%20filing%2014-E-0454%20VS%20Assmnt%20Western%20NY%20PPTN.pdf.

⁴⁵ NYISO determined that two developers (NRG Dunkirk Power and ITC New York Development) were unqualified.

⁴⁶ NYISO no longer considered the two projects from AvanGrid, Inc. (parent company of New York State Electric and Gas Corporation and Rochester Gas and Electric) and one project from GlidePath Power LLC because the projects were not viable.

⁴⁷ North American Transmission is a subsidiary of LS Power.

⁴⁸ See <https://www.spp.org/about-us/newsroom/spp-board-votes-to-lower-planning-reserve-margins-award-first-competitively-bid-project-approve-363m-in-transmission-upgrades/>.

⁴⁹ The member cooperatives are Lane-Scott Electric Cooperative, Inc., Prairie Land Electric Cooperative, Inc., Southern Pioneer Electric Company, The Victory Electric Cooperative Association, Inc., Western Cooperative Electric Association, Inc., and Wheatland Electric Cooperative, Inc.

⁵⁰ The participant associated with this proposal is Big Rivers, which has three member cooperatives: Jackson Purchase Energy Corporation; Kenergy Corporation; (Kenergy); and Meade County Rural Electric Cooperative Corporation. Kenergy serves the area around the Coleman facility in Hancock County, Kentucky.

as incumbents and the two others (Ameren Transmission Company of Illinois/PPL TransLink, Inc., and Transource Energy⁵¹) as nonincumbents.

In reviewing the results of the competitive transmission development processes in CAISO, MISO, NYISO, PJM, and SPP, staff has observed that there is some indication that when a range of different solutions located in different transmission zones (i.e., incumbent transmission owners' footprints) can resolve the violations posted as part of a competitive proposal window, incumbents submit a greater percentage of the total proposals than when the range of potential solutions to a transmission need subject to a proposal window is more geographically limited or, in the case of transmission planning regions that have adopted competitive bidding models, when the transmission planning region has already identified a transmission solution. For example, under CAISO's competitive bidding model all of the proposal windows involved specific transmission lines, substations, or reactive power support in a given area or at a particular point, and the share of proposals from nonincumbents ranged from 67 percent (2015) to 78 percent (2013). Similarly, the single proposal windows in MISO and SPP both involved specific transmission lines and, while staff does not have data for SPP (as described above), nonincumbents submitted 73 percent of the total proposals submitted in MISO.

In contrast, PJM's various proposal windows included violations with a more limited range of potential solutions and violations with a wider range of potential solutions. For example, PJM's 2015 proposal windows announced violations that could be resolved by a more limited range of potential solutions, and the share of proposals from nonincumbents exceeded that from incumbents (58 percent versus 42 percent). In 2014, on the other hand, all of PJM's announced violations had a range of potential solutions located in multiple transmission zones,⁵² and incumbents submitted 63 percent of proposals. The preliminary results for PJM from 2016, in which PJM's proposal windows addressed violations with a similarly wide range of potential solutions, are consistent with this hypothesis – incumbents accounted for 54 percent of the proposals that year. However, the results from 2013, in which PJM's proposal windows included both violations with a limited range of potential solutions and violations with a wider range of potential solutions, is less supportive of staff's observation. In that year, nonincumbents in PJM accounted for 67 percent of the proposals submitted.

Staff's observation is further supported by the results of the proposal windows in NYISO. In NYISO's 2015 proposal window, the range of potential solutions was limited to a particular transmission zone (Zone A), and nearly 60 percent of the valid proposals that year came from nonincumbents. Conversely, in NYISO's 2016 proposal window, the range of potential solutions spanned three transmission zones: Mohawk Valley (Zone E), Capital (Zone F), and Hudson Valley (Zone G). Incumbents submitted 56 percent of the proposals in response to this proposal window.

⁵¹ Transource Energy is a partnership between American Electric Power and Great Plains Energy. Transource Indiana, LLC, and Transource Kentucky, LLC participated in this proposal.

⁵² The 2014 RTEP 1 and 2014 RTEP 2 proposal windows specified reliability criteria violations at various facilities within PJM's footprint, while the 2014/15 Long Term RTEP considered reliability criteria violations, market efficiency congestion, and Reliability Pricing Model (RPM) constraints on facilities.

Compared to last year's analysis, this updated metric is more representative of competitive transmission development processes across different transmission planning regions, as it includes new competitive proposal windows from PJM, NYISO, SPP, and MISO. However, staff cautions that transmission planning regions implemented their competitive transmission development processes too recently for staff to describe a "typical" proposal year, expected proposals, and resulting selections in this report. First, staff's analysis continues to be geographically limited; ISO New England (ISO-NE) and the non-RTO/ISO transmission planning regions have yet to open proposal windows. Second, two regions – SPP and MISO – have each had only one proposal window.

In the 2016 Report, staff hypothesized that PJM may open more and larger proposal windows in even-numbered years than in odd-numbered years because of the nature of its 24-month planning cycle.⁵³ In 2014, PJM opened two short-term windows and one long-term window with 304 proposals received in response, while in 2015 it opened only two short-term windows (2015 RTEP 1 and 2015 RTEP 2) with 128 proposals received in response.⁵⁴ Staff points to the 2016 proposal windows as data supporting this hypothesis, as PJM opened four short-term windows (2016 RTEP 1, 2016 RTEP 2, 2016 RTEP 3, and 2016 RTEP 3 Addendum) and one long-term window (2016/17 RTEP Long-Term Proposal) in 2016. While the proposal information for the 2016/17 RTEP Long-Term Proposal window has yet to be posted on PJM's website, PJM has already received 147 proposals in the first four windows of 2016, which already exceeds the number of proposals received in 2015. Moreover, staff anticipates that PJM will receive a large number of proposals in its 2016/17 Long Term Proposal window – as a comparison, submissions for the 2014/15 Long Term Proposal window accounted for 39 percent of all proposals PJM received in 2014.

Staff also questioned in the 2016 Report whether PJM's adoption of the sponsorship model resulted in its receipt of more than 10 times the proposals that CAISO, which adopted a competitive bidding model, has received. Staff previously found this hypothesis difficult to test because at that time, no other transmission planning regions had opened proposal windows. Now that proposal information from MISO, NYISO, and SPP is available, staff is able to make some preliminary observations based on the expanded data. In its two proposal windows, NYISO – which uses a sponsorship model like PJM – received a total of 28 proposals (12 in 2015 and 16 in 2016). These values are more in line with the number of proposals received by CAISO, MISO, and SPP, all of which use competitive bidding models. Therefore, staff concludes that there may be some other characteristic of PJM's competitive proposal window process, besides the model of competitive transmission development process that it chose to adopt, that explains

⁵³ PJM has a 24-month transmission planning process consisting of two 12-month cycles to examine immediate needs (fewer than 3 years in the future) and short-term needs (3-5 years in the future), and a 24-month cycle to examine long-term needs (15 years in the future). Projects needed in fewer than 3 years are not subject to a proposal window, and are therefore not included in this analysis. See <http://pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows.aspx>, and PJM, 2014 Regional Transmission Expansion Plan: Book 2 (Input Data and Process Scope), at 15, <http://pjm.com/-/media/documents/reports/2014-rtep/2014-rtep-book-2.ashx>.

⁵⁴ PJM also opened two windows in 2015 that were addenda to the 2014 RTEP 2 proposal window; PJM received relatively few proposals in response to both. Those proposals were included as part of staff's analysis of the proposals that PJM received in 2015.

the relatively large number of proposals that it receives. One potential explanation is that PJM's proposal windows include numerous reliability standard violations and, consequently, may result in the selection of many transmission projects. In contrast, the proposal windows in CAISO, MISO, and SPP under the competitive bidding model include only one specific project per proposal window. Similarly, while NYISO uses a sponsorship model, its proposal windows tend to include a more limited number of violations that lend themselves toward a more limited solution, such that NYISO is likely to select fewer proposals per proposal window. As noted above, PJM's proposal windows also tend to include reliability standard violations that could be resolved by a wider range of different, geographically disperse transmission solutions than is typically the case in the other transmission planning regions. Staff believes that this wider range of solutions could also potentially help to explain why PJM receives more proposals.

Staff notes that, on August 26, 2016, the Commission issued an order that permitted PJM to revise the tariff rules governing its competitive proposal window process to exclude reliability violations on transmission facilities operating below 200 kV from that process.⁵⁵ Thus, staff hypothesizes that the number of proposals in PJM post-2016 may fall as fewer violations are subject to proposal windows. Staff intends to review the future data to test this hypothesis.

Caveats

Now that another year has passed, this metric provides more useful information about the degree of nonincumbent participation in Order No. 1000 regional transmission planning processes. However, one should be cautioned from relying too heavily on these results to determine degree of nonincumbent participation. As noted above, ISO-NE and the non-RTO/ISO transmission planning regions have yet to hold proposal windows under Order No. 1000. Moreover, two regions (SPP and MISO) have each held only one proposal window, with SPP ultimately cancelling the selected project and making the identity of only the winner and runner up available to the public. As a result, staff believes it is still too early to tell whether the limited number of proposal windows in CAISO, PJM, NYISO, SPP, and MISO will prove representative of future proposal windows.

The greater number of proposal windows in PJM and the addition of three new transmission planning regions in the 2017 Report has indicated that joint ventures and consortia may be submitting more proposals in regional transmission planning processes. The current methodology of categorizing transmission developers as either incumbents or nonincumbents may mask the activity of particular entities that are involved in joint ventures or consortia. Specifically, labeling a joint venture that includes an incumbent transmission developer and a nonincumbent transmission developer as strictly an incumbent transmission developer does not recognize the participation of the nonincumbent transmission developer. As a result, staff would like to investigate the prevalence of joint ventures and consortia that involve both incumbent and nonincumbent transmission developers. In future reports, staff plans to categorize a given transmission developer as either an incumbent transmission developer, a nonincumbent transmission developer, or a combined developer (i.e., a joint venture or

⁵⁵ See PJM Interconnection, L.L.C. 156 FERC ¶ 61,132 (2016).

consortium that includes both an incumbent and nonincumbent transmission developer). Under this new categorization system, incumbent transmission developers and nonincumbent transmission developers could be single entities or they could be either joint ventures or consortia that are comprised of strictly incumbent or nonincumbent transmission developers, respectively.

NUMBER OF UNIQUE DEVELOPERS SUBMITTING PROPOSALS

Background

As an additional measure of the competitiveness of Order No. 1000 competitive transmission development processes, this metric seeks to measure the number of unique developers that participate in transmission planning regions' competitive transmission development processes by submitting proposals, regardless of their incumbency status. Staff believes that this metric may serve as one indication of how competitive the competitive transmission development processes implemented to comply with Order No. 1000 are, as it measures the number of unique developers that participate in these processes. As noted above, transmission planning regions have adopted either a sponsorship model or a competitive bidding model to comply with Order No. 1000. It is possible that one type of model may lend itself to participation by more unique developers than the other. Therefore, staff also intends this metric to help provide a better understanding of whether one model of competitive transmission development process may attract more unique developers, and thus potentially more competition, than the other.

Methodology

To calculate this metric, staff used data from the various transmission planning regions' proposal windows that were posted on their respective websites, which are the same sources to calculate the nonincumbent percentage of proposals metric above. Staff identified the number of unique developers that submitted a proposal in response to a proposal window, tabulating them by transmission planning region and by year. Staff defined a unique developer in a given year as either a particular incumbent, nonincumbent, consortium, or joint venture regardless of their incumbency status. For purposes of its analysis, staff considered entities that submitted separate proposals but that are owned by a single parent company to be a single, unique developer. Lastly, staff identified consortia as unique developers, even though members of a consortium may be affiliated with other unique developers. This is because staff assumed that the process of negotiating among consortium members will result in a unique set of blended interests that differs from the particular interests of any individual consortium member.

Results and Analysis

Figure 2 below shows the total number of unique developers that submitted proposals in CAISO's, MISO's, NYISO's, PJM's, and SPP's competitive transmission development processes by year. Between 2013 and 2016, the number of unique developers in a given transmission planning region in any year ranged from 3 to 22 entities, while most of the totals hovered between 6 and 11 unique developers.

Figure 2
Number of Unique Developers and Average Proposals per Developer by Year and RTO/ISO

RTO/ISO	2013		2014		2015		2016	
	Total Submissions	Number of Unique Developers (Average Proposals per Developer)	Total Submissions	Number of Unique Developers (Average Proposals per Developer)	Total Submissions	Number of Unique Developers (Average Proposals per Developer)	Total Submissions	Number of Unique Developers (Average Proposals per Developer)
CAISO	9	7 (1.3)	19	9 (2.1)	3	3 (1.0)	---	---
PJM	43	10 (4.3)	304	22 (13.8)	128	11 (11.6)	147*	16* (9.2)
NYISO	---	---	---	---	12	7 (1.7)	16	6 (2.7)
SPP	---	---	---	---	11	N/A**	---	---
MISO	---	---	---	---	---	---	11	11 (1.0)

* Includes the 2016 RTEP 1, 2016 RTEP 2, 2016 RTEP 3, and 2016 RTEP 3 Addendum proposal windows, but excludes the 2016/17 RTEP Long Term Proposal window.

** The total number of unique developers in SPP is not known since the identities of the developers were masked in the selection report and SPP announced the names of the winner and runner up in a press release on its website.

Staff's analysis did not yield any general observations about the number of unique developers compared across years or across transmission planning regions using different models of competitive transmission development processes.

On a regional basis, CAISO's experience with unique developers has varied over time. In 2014, nine unique developers submitted a total of 19 proposals (2.1 proposals per developer). In 2013, the developers submitted fewer proposals in 2013 (1.3 proposals per developer). In 2015, unique developers each submitted one proposal.

By far, PJM had the most proposals over the four-year period, largely due to the inclusion of projects related to reliability violations on transmission facilities operating below 200 kV. Because developers devise solutions for transmission planning regions' needs under the sponsorship model, that competitive transmission development process lends itself to multiple submissions from any one developer. PJM's proposal data illustrates this observation – in 2014, PJM received 304 proposals that ultimately came from 22 unique developers (13.8 proposals per developer), and in 2015, PJM received 128 proposals from 11 unique developers (11.6 proposals per developer).

After considering the proposals that NYISO disqualified as incomplete, unique developers in NYISO submitted approximately two proposals per developer. In MISO, each proposal came from a unique developer. Staff could not determine the number of unique developers in SPP's sole competitive proposal window due to the transmission planning region's confidentiality protocols.

Caveats

This metric provides some insight into the number of unique developers that have participated in competitive transmission development processes. However, one should be cautioned from relying too heavily on these results. As noted above, ISO-NE and the non-RTO/ISO transmission planning regions have yet to hold proposal windows under Order No. 1000. Moreover, SPP and MISO have each held only one proposal window, with SPP ultimately cancelling the selected project. As a result, staff believes it is still too early to tell whether the limited number of proposal windows in CAISO, PJM, NYISO, SPP, and MISO will prove representative of future proposal windows.

NUMBER AND PERCENTAGE OF SELECTED NONINCUMBENT PROPOSALS

Background

This metric measures the number of nonincumbent proposals that each transmission planning region selected in each year for which staff has data. The metric also shows the percentage of the total selected proposals that nonincumbents submitted. Staff intends this metric to help assess whether nonincumbents are likely to have continued interest in participating in competitive transmission development processes going forward. For example, a high selection

rate of nonincumbent proposals would seem to encourage more nonincumbents to submit proposals as they may be less likely to view the competitive transmission development process as unduly discriminatory towards nonincumbents when a transmission planning region has selected nonincumbent proposals in the past

Methodology

To calculate this metric, staff primarily used data from the transmission planning region's websites. For CAISO and MISO, staff used information about their selection decisions that they posted on their respective websites.⁵⁶ In PJM, the Transmission Expansion Advisory Committee sends its recommended selections to the PJM Board of Managers in the form of a white paper for review. PJM then publishes annual reports on the PJM Board of Managers' decisions on those recommendations. Staff gathered data on selected proposals in PJM from these annual reports, as well as the Transmission Expansion Advisory Committee's monthly presentations.⁵⁷ The winner from SPP's competitive window was announced on the transmission planning region's website.⁵⁸ While NYISO has opened two proposal windows, as of the preparation of this report, it had yet to select any proposals and thus staff had no data from NYISO to include when calculating this metric.

Staff identified the total number of proposals selected each year in the four transmission planning regions that have made selection decisions (i.e., CAISO, MISO, PJM, and SPP). Staff determined whether each selected proposal was submitted by an incumbent or nonincumbent. Staff then calculated the percentage of selected proposals that nonincumbents submitted.

⁵⁶ See <http://www.caiso.com/planning/Pages/TransmissionPlanning/2012-2013TransmissionPlanningProcess.aspx> and <http://www.caiso.com/planning/Pages/TransmissionPlanning/2013-2014TransmissionPlanningProcess.aspx> for CAISO and

https://www.misoenergy.org/Library/Repository/Study/Transmission%20Developer/20161220_FINAL_Selection%20Report_SRPT_v1.pdf for MISO.

⁵⁷ For preliminary results for 2016 RTEP 1, see "Transmission Expansion Advisory Committee 2016 PJM Board Recommendation Webcast" from the Transmission Expansion Advisory Committee (June 23, 2016) at <http://mediastream.pjm.com/2016/0623/teac/reliability-analysis-update-webcast/index.htm>. The recommended projects for 2016 RTEP 2 and 2016 RTEP 3 can be found in the TEAC meeting notes at <http://www.pjm.com/committees-and-groups/committees/teac.aspx>. For a summary of the 2014/15 RTEP Long Term Proposal, 2015 RTEP 1, and 2015 RTEP 2, see <http://www.pjm.com/-/media/documents/reports/2015-rtep/2015-rtep-book-1.ashx> at 8. For detailed information on the 2013 Artificial Island window, 2015 RTEP 1, 2015 RTEP 2, and 2014 RTEP 2 Addendum 2 see <http://www.pjm.com/-/media/documents/reports/2015-rtep/2015-rtep-book-3.ashx> at 21-27, 84, 100-105, and 109-110. For a detailed analysis of the Board-recommended bids for 2014 RTEP 1 and 2014 RTEP 2, see <http://www.pjm.com/-/media/documents/reports/2014-rtep/2014-rtep-book-3.ashx> at 39-43 and 58-62. For information about the recommended bid in the 2013 Market Efficiency proposal window, see <http://www.pjm.com/-/media/documents/reports/2013-rtep/2013-rtep-book-3.ashx> at 118-119.

⁵⁸ See <https://www.spp.org/about-us/newsroom/spp-board-votes-to-lower-planning-reserve-margins-award-first-competitively-bid-project-approve-363m-in-transmission-upgrades/>.

Results and Analysis

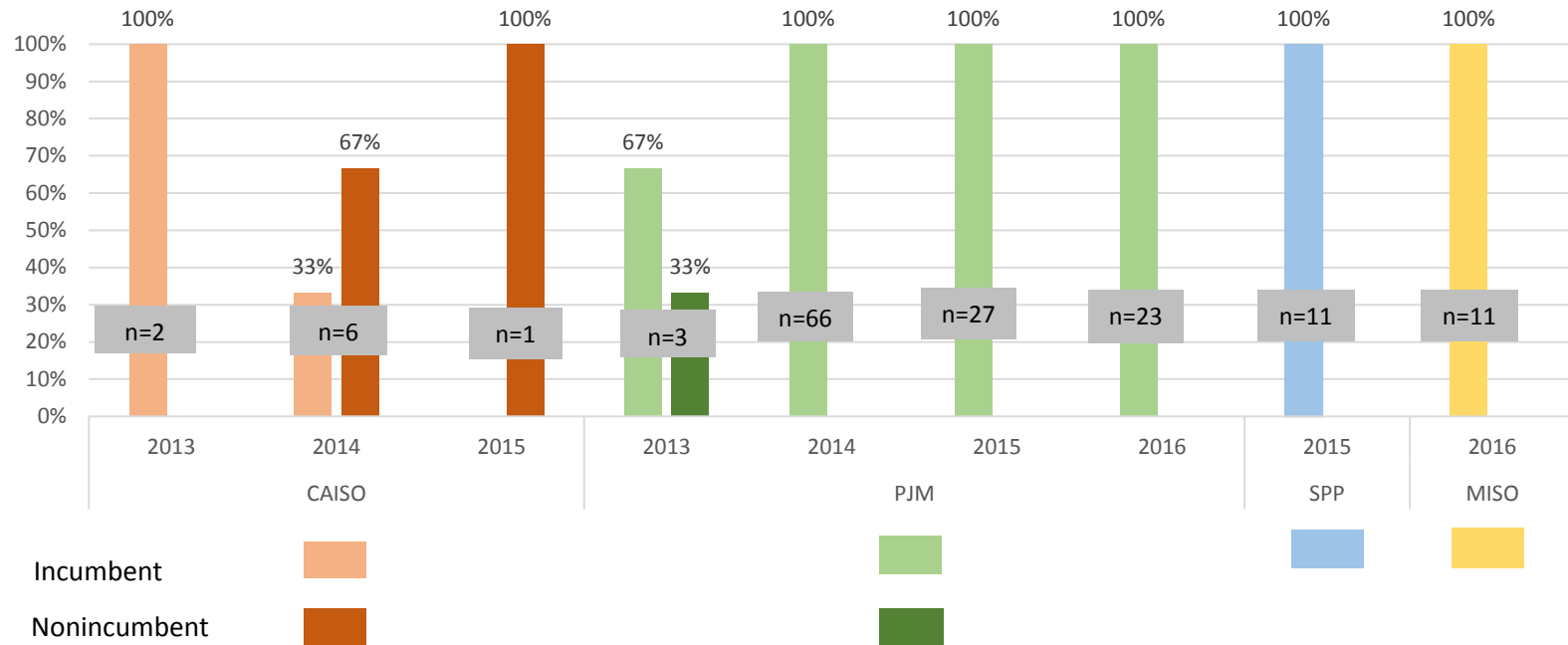
Figure 3 below shows the total number of proposals that each transmission planning region selected each year, as well as the number and percentage of selected proposals that nonincumbents submitted. Overall, staff observes that, other than in CAISO, most of the proposals that the transmission planning regions selected were submitted by incumbents.

In CAISO, the number and percentage of selected proposals that nonincumbents submitted appear to have risen over time. In 2013, incumbents submitted both of the proposals that CAISO selected. However, in 2014, nonincumbents submitted four of the six proposals (67 percent) that CAISO selected and in 2015, a nonincumbent submitted the single proposal that CAISO selected (out of three proposals submitted).

The three other transmission planning regions that have selected proposals in their competitive transmission development processes have selected fewer nonincumbent proposals. PJM did not select any nonincumbent proposals between 2014 through the third competitive window of 2016. PJM also selected an incumbent proposal as a result of the 2013 Market Efficiency Proposal Window. PJM co-selected a nonincumbent proposal for the 2013 Artificial Island project – the PJM Board of Directors recommended using part of the nonincumbent’s proposal and combined it with work that would be done by an incumbent. Thus, of the three proposals (or parts of proposals) that PJM selected as a result of its 2013 proposal windows, only one was a nonincumbent proposal. SPP and MISO have only had one proposal window each, and both selected proposals that incumbents submitted.⁵⁹

⁵⁹ In MISO, the selected developer, Republic Transmission, wholly owned by LS Power Associates, L.P. (LS Power), partnered with Big Rivers, which has three member cooperatives – Jackson Purchase Energy Corporation, Kenergy Corporation, (Kenergy), and Meade County Rural Electric Cooperative Corporation. Kenergy serves the area around the Coleman facility in Hancock County, Kentucky. Moreover, LS Power entered into an agreement with Hoosier Energy to acquire a percentage ownership of Republic Transmission. Hoosier Energy’s service area includes Dubois County, Indiana, the same county where the Duff substation is located. Thus, staff classified Republic Transmission as an incumbent, given its joint proposal with Big Rivers; however, Republic Transmission, a nonincumbent, is solely responsible for developing the Duff-Coleman project. SPP selected Mid-Kansas Electric Company, which is a consortium of electric cooperatives operated by Sunflower Electric Power Corporation. The North Liberal-Walkemeyer 115 kV transmission line project notes that the North Liberal substation is owned by Mid-Kansas Electric Company, while the Walkemeyer substation is owned by Sunflower Electric Power Corporation. Thus, staff classified Mid-Kansas Electric Company as an incumbent.

Figure 3
Number and Percentage of Awards Made to Nonincumbents by Year and RTO/ISO



* Only Market Efficiency Proposals in PJM were selected in 2013. While the review of Artificial Island proposals continued into 2015, the final selections associated with that project were counted under the 2013 proposal window year.

** Covers PJM's 2016 RTEP 1, 2016 RTEP 2, and 2016 RTEP 3 and are only TEAC recommendations to the PJM Board. Thus, the selections for the 2016 year are not final.

*** NYISO has yet to select a proposal from its two solicitations.

Caveats

While this metric sheds some light on nonincumbents' success in competitive transmission development processes, staff finds that several caveats are warranted. As noted above, staff identified nonincumbents as either stand-alone entities, consortia, or joint ventures, so long as the project falls outside of the company's (companies') retail distribution service territory (territories) or footprint(s). Staff categorized joint ventures and consortia that include incumbents and nonincumbents as incumbents if the project was located in the incumbent's retail distribution service territory or footprint. Therefore, this metric does not capture the fact that in some cases, the joint venture associated with a selected proposal may include a nonincumbent (e.g., MISO's selection of a proposal submitted by both Republic Transmission, a nonincumbent, and Big Rivers Electric Corporation, an incumbent). This shortcoming will be alleviated in future reports when staff categorizes transmission developers as incumbent transmission developers, nonincumbent transmission developers, or combined developers. With this revised methodology, staff will better recognize the participation of nonincumbent transmission developers that partner with incumbent transmission developers to submit proposals. In addition, the number of transmission planning regions that have held proposal windows, and the number of proposal windows that they have held, is limited, making it difficult to draw any conclusions from the data at this time.

STAKEHOLDER PARTICIPATION IN REGIONAL TRANSMISSION PLANNING PROCESSES

Background

The metric, included as a new metric for the 2017 Report, measures stakeholder participation in regional transmission planning processes. In the past, this metric was reported separately. Specifically, the Commission's Strategic Plan for fiscal years 2014-2018 requires staff from the Office of Energy Market Regulation (OEMR) to assess the potential effectiveness of Order No. 1000 in encouraging greater participation in the regional transmission planning processes, thus promoting more efficient and cost-effective transmission solutions.⁶⁰

Methodology

To collect data for this metric, OEMR staff attended and monitored stakeholder participation in at least three to four regional transmission planning meetings held by each of the 12 Order No. 1000 transmission planning regions⁶¹ during FY 2015 and FY 2016.⁶² OEMR staff recorded the stakeholders that participated in these meetings by phone and reviewed participation lists that the meeting organizers provided to staff. Staff measured the level of participation by counting the total number of participants attending the meetings.⁶³ In addition, staff measured the number of participants in three categories: (1) public utility transmission providers; (2) transmission customers;⁶⁴ and (3) nonincumbent transmission developers. Staff then computed the averages for each category of stakeholder for each region by adding up the total number of attendees in each category of stakeholder (or in the case of Figure 4, the total number of attendees in all three categories of stakeholders) and then divided by the number of meetings monitored for a particular region.⁶⁵ Staff believes averaging the attendance numbers for the various meetings staff monitored provides a more accurate reflection of attendance than a simple

⁶⁰ See <https://www.ferc.gov/about/strat-docs/FY-2014-FY-2018-strat-plan.pdf> at 10-11.

⁶¹ The Order No. 1000 transmission planning regions are: CAISO; ColumbiaGrid; Northern Tier Transmission Group (NTTG); WestConnect, MISO; SPP; Florida Reliability Coordinating Council (FRCC); ISO-NE; NYISO; PJM; Southeastern Regional Transmission Planning (SERTP); and South Carolina Regional Transmission Planning (SCRTP).

⁶² The authors of this report would like to acknowledge the OEMR staff who collected and compiled the stakeholder attendance data for FY 2015 and FY 2016. They include: Gabriel Aguilera; Adam Bednarczyk; James Brennan; Nicole Buell; Michael Cackoski; Patrick Clarey; Nicole Cramer; James Eason; Saeed Farrokhpay; Jonathan Fernandez; Alina Halay; Franklin Jackson; Eric Jacobi; Rhonda Jones; Michael Lee; Christopher Mahon; Valerie Martin; Matthew McWhorter; Christopher Miller; Peter Nagler; Al Padron; Penny Payne; Natalie Propst; Rajiv Raja; Navin Shekar; Jay Sher; Jason Strong; and Gary Will.

⁶³ Staff counted representatives from the same entity as one participant regardless of the number of individuals that the entity may send to a meeting.

⁶⁴ Transmission customers include demand-side stakeholders (such as load, state commissions, and consumer advocacy groups) and supply-side stakeholders (such as generators).

⁶⁵ The sum of the averages for the three stakeholder categories does not equal the total number of attendees reported in Figure 4 due to several factors, including: (1) rounding; (2) the lack of attendee lists for NYISO's meetings (discussed in footnote 66 below); and a change in the coding of the nonincumbent attendees at the MISO meetings (discussed below with Figure 7).

count because stakeholder participation fluctuates between meetings held at different times in the transmission planning cycles.

Results and Analysis

Figures 4 through 7 below show the average attendance figures for all stakeholders and for each of the three categories of stakeholders for each transmission planning region for FY 2015, the first year that staff began collecting the data for all 12 regions, and for FY 2016.

Figure 4 shows that the average attendance by all stakeholders dropped off slightly in most transmission planning regions from FY 2015 to FY 2016. This pattern holds among both RTOs/ISOs and non-RTO/ISO transmission planning regions although some regions – NTTG, FRCC, SERTP, and SCRTP – showed increases.⁶⁶

Figure 4
Average Number of Participants Attending
Regional Transmission Planning Meetings during FY 2015 and FY 2016

Region	Average Number of Participants in Attendance		
	FY 2015	FY 2016	Difference
CAISO	57	55	-2
ColumbiaGrid	20	16	-4
NTTG	24	29	5
WestConnect	33	32	-1
MISO	90	89	-1
SPP	43	35	-8
NYISO	44	39	-5
ISO-NE	28	30	2
PJM	85	80	-5
FRCC	11	14	3
SERTP	26	29	3
SCRTP	8	10	2
Total	469	458	-11

⁶⁶ Staff has requested NYISO to provide a list of attendees for each regional transmission planning meeting so that staff can separate participants into the three categories required by the Strategic Plan. However, NYISO only reports overall attendance numbers and thus far has not provided the requested lists.

Figure 5 shows that the average attendance by public utility transmission providers remained stable in all transmission planning regions, with only minor increases or decreases between FY 2015 and FY 2016.

Figure 5
Average Number of Public Utility Transmission Providers
Attending Regional Transmission Planning Meetings during FY 2015 and FY 2016

Region	Average Number of Public Utility Transmission Providers in Attendance		
	FY 2015	FY 2016	Difference
CAISO	6	4	-2
ColumbiaGrid	14	13	-1
NTTG	6	6	0
WestConnect	12	12	0
MISO	22	25	3
SPP	16	14	-2
NYISO	Unavailable	Unavailable	n/a
ISO-NE	11	8	-3
PJM	28	29	1
FRCC	3	4	1
SERTP	12	14	2
SCRTP	3	3	0
Total	133	132	-1

Figure 6 shows that transmission customers' attendance decreased significantly in SPP, increased moderately in ISO-NE, and held steady in the remaining transmission planning regions.

Figure 6
Average Number of Transmission Customers
Attending Regional Transmission Planning Meetings during FY 2015 and FY 2016

Region	Average Number of Transmission Customers in Attendance		
	FY 2015	FY 2016	Difference
CAISO	41	40	-1
ColumbiaGrid	2	2	0
NTTG	18	20	2
WestConnect	15	14	-1
MISO	60	57	-3
SPP	29	15	-14
NYISO	Unavailable	Unavailable	n/a
ISO-NE	15	22	7
PJM	50	47	-3
FRCC	5	6	1
SERTP	13	13	0
SCRTP	5	6	1
Total	253	242	-11

Figure 7 shows that meeting participation rates by nonincumbents were stable from FY 2015 to FY 2016. Staff identified a major drop in nonincumbent attendance in MISO, but staff believes a difference in the method of coding attending parties in FY 2015, by coding parties in more than one category, may have led to this difference. Staff also found no significant drop in meeting participation by nonincumbents over the two fiscal years in other transmission planning regions, and identified increases in nonincumbent participation in four regions. Additionally, nonincumbents are active in practically every transmission planning region, with the exception of ISO-NE and SCRTP.

Figure 7
Average Number of Nonincumbents
Attending Regional Transmission Planning Meetings during FY 2015 and FY 2016

Region	Average Number of Nonincumbents in Attendance		
	FY 2015	FY 2016	Difference
CAISO	11	11	0
ColumbiaGrid	4	1	-3
NTTG	1	2	1
WestConnect	6	6	0
MISO	19	7	-12
SPP	4	6	2
NYISO	Unavailable	Unavailable	n/a
ISO-NE	0	0	0
PJM	4	4	0
FRCC	3	4	1
SERTP	1	2	1
SCRTP	0	0	0
Total	53	43	-10

The major finding from this overview of stakeholder attendance at regional transmission planning meetings during FY 2015 and FY 2016 is one of stability in stakeholder participation in the transmission planning process in both RTOs/ISOs and non-RTO/ISO transmission planning regions. Most of the increases or decreases staff observed during this time were not dramatic. The decrease in nonincumbent participation in MISO’s regional transmission planning meetings appears to be tied to a coding issue and not an actual drop in nonincumbent participation. Staff notes that as the Commission sought to facilitate in Order No. 1000, nonincumbent transmission developers are engaged in the stakeholder process in regional transmission

planning in most transmission planning regions, with increases in participation found in four regions.

Caveats

Overall, the stakeholder participation data indicate that the average numbers of total participants, Public Utility Transmission Providers, transmission customers, and nonincumbents were relatively stable between FY 2015 and FY 2016. It is important to note that this metric only considers two years of data. As a result, the findings may not be representative of a longer time period. Moreover, the regional transmission planning processes are relatively new, and participation may increase over time as stakeholders become more comfortable with the process.

II. Metric to Indicate Whether Appropriate Levels of Transmission Infrastructure Exist

This category of metrics attempts to use price data to assess whether transmission investment in the RTOs/ISOs is adequate. Price differentials between areas within an RTO/ISO may be the result of inadequate transmission capacity, capacity that is necessary to deliver power from areas with lower prices to those with higher prices. However, not all price differentials can be addressed economically; in some cases, the costs associated with the transmission infrastructure necessary to reduce a price differential may exceed the benefits that alleviating that congestion could provide. In such cases, persistent price differentials do not necessarily indicate insufficient transmission investment.

RTO/ISO MARKET PRICE DIFFERENTIAL

Background

As discussed in more detail in the 2016 Report, staff reasons that multiple consecutive years of significant price differences could indicate insufficient transmission infrastructure, while bearing in mind that additional investment in transmission infrastructure to reduce those differences may not be economic in all cases.

Methodology

Staff focused on individual points or areas where historical electricity prices or locational marginal prices (LMPs) were significantly different from the average of the LMPs in the surrounding areas.

In RTO/ISO markets, where prices reflect congestion costs, a point where anomalous LMPs occur persistently should indicate congestion on the transmission interfaces linking the point with other parts of the transmission system. In contrast, in an area without congestion, LMPs should all be essentially the same, differing perhaps only by virtue of the varying marginal losses at each point. Thus, the persistent occurrence of high or low prices at a given point relative to the rest of the market suggests transmission investment could be needed, at least where such investment is economic.

To calculate this metric, staff used real-time LMPs at load and generator points from ABB Velocity Suite and other sources.⁶⁷ The data covered the period January 1, 2000, to December 31, 2015. To avoid placing excessive weight on highly unusual prices, staff used the 95th and 5th percentiles of prices, rather than maximum or minimum prices, at each load and generator point. Staff then calculated the average 95th and 5th percentiles of prices at all of the points in the market to identify a market-wide average 95th percentile price and a market-wide average 5th percentile price for each RTO/ISO. Using this information, staff identified those points whose 95th or 5th percentile price were, compared to the market-wide averages, either significantly high or significantly low.

To determine whether a price was significantly high or low compared to the market-wide averages, staff relied on a common statistical concept, the standard deviation. Staff considered a location “high-priced” in a year if the 95th percentile of prices at that point was more than one standard deviation above the average of the 95th percentiles of all points in the market. Similarly, staff considered a location to be “low-priced” in a year if the 5th percentile of prices at that point was more than one standard deviation below the average of the 5th percentiles of all points in the market. This approach finds points where the high prices in a year were high relative to the average of the high prices in the same year for the entire market the points are in, as well as points where the low prices in a year were low relative to the average of the low prices in the same year for the entire market the points are in. For example, if the average of the 95th percentile of real-time LMPs is \$150/MWh in an RTO/ISO (for generator price points) and the standard deviation of the 95th percentile of real-time LMPs is \$300/MWh, the threshold for counting generator price points as high-priced would be \$450/MWh. Thus, the 95th percentile of the real-time LMPs at a point would have to be at least \$450/MWh for the point to be characterized as high-priced.

Staff identified points with high or low prices in 2012 through 2015 to determine the points at which price separation occurred persistently and likely has not yet been resolved. To focus on the persistence of price separations, staff then tallied the number of years in which the current run of high or low prices began. Finally, staff identified areas within each RTO/ISO that encompassed multiple neighboring points with persistent price separations in the same direction, identified for each area the longest period of price separation experienced by a pricing point included in that area, and used that number of years as the RTO/ISO Price Differential metric for that region.

Results and Analysis

Using ABB Velocity Suite data through 2015 and price information from SPP from 2014 through 2015, staff found 1,482 generator or load points in Commission-jurisdictional RTOs/ISOs where relatively high or low real-time LMPs occurred persistently.

⁶⁷ Following the implementation of SPP’s Integrated Marketplace, ABB Velocity Suite no longer provides yearly pricing data for SPP, so staff aggregated real-time price data directly from SPP. See [ftp://pubftp.spp.org/Markets/RTBM/LMP_By_BUS/](http://pubftp.spp.org/Markets/RTBM/LMP_By_BUS/).

Staff found 13 areas within RTOs/ISOs in the U.S. where either persistently high and/or low prices existed. For each area, Figure 8 lists the price direction, year in which the price separation began, and the number of years the price separation has persisted. Many of the areas identified have experienced either low or high relative prices for a substantial period of time. Of additional note, staff identified continued areas of low- and high-priced points from the 2016 Report in the North-Central MISO, Greater Chicago, North Dakota-South Dakota-Minnesota Border, West-Central North Dakota, Upper Peninsula, New York-Canada Border, Northern New York, Long Island, Baltimore, and Delmarva areas, which may suggest very localized constrained facilities.

Figures 9 through 12 below show the areas with more than one high-priced or low-priced point, as defined, and the points themselves. Specifically, Figure 9 shows the 13 areas in which staff found instances of persistent high or low prices. Figure 10 indicates the low-price points in the various regions. Generator points are represented by solid squares and load points by hollow squares; different colors represent the number of years that price differentials persisted.⁶⁸ As Figure 10 shows, staff found a large number of low-priced points in the middle of the country, particularly North-Central MISO, the Greater Chicago area, and Western Texas, as well as in the New York-Canada Border Region, Northern New York, West-Central North Dakota, and the North Dakota-South Dakota-Minnesota Border Region.

Similarly, Figure 11 shows high-priced points, with generator points represented by solid stars and load points by hollow stars. Again, the colors represent the number of years the price differentials persisted.⁶⁹ As shown in Figure 11, staff identified eight areas with high-priced points, including Baltimore, the Upper Peninsula, North-Central MISO, Delmarva, Northwestern New Jersey, the Greater Chicago Area, Long Island, Western Texas, and Central California. Figure 12 combines the low and high-price maps.

⁶⁸ The years in which the persistently low prices began to were grouped into three categories: 2005 to 2007, 2008 to 2010, and 2012 to 2013.

⁶⁹ As with Figure 10, the years in which persistently high prices began were grouped into the same three categories.

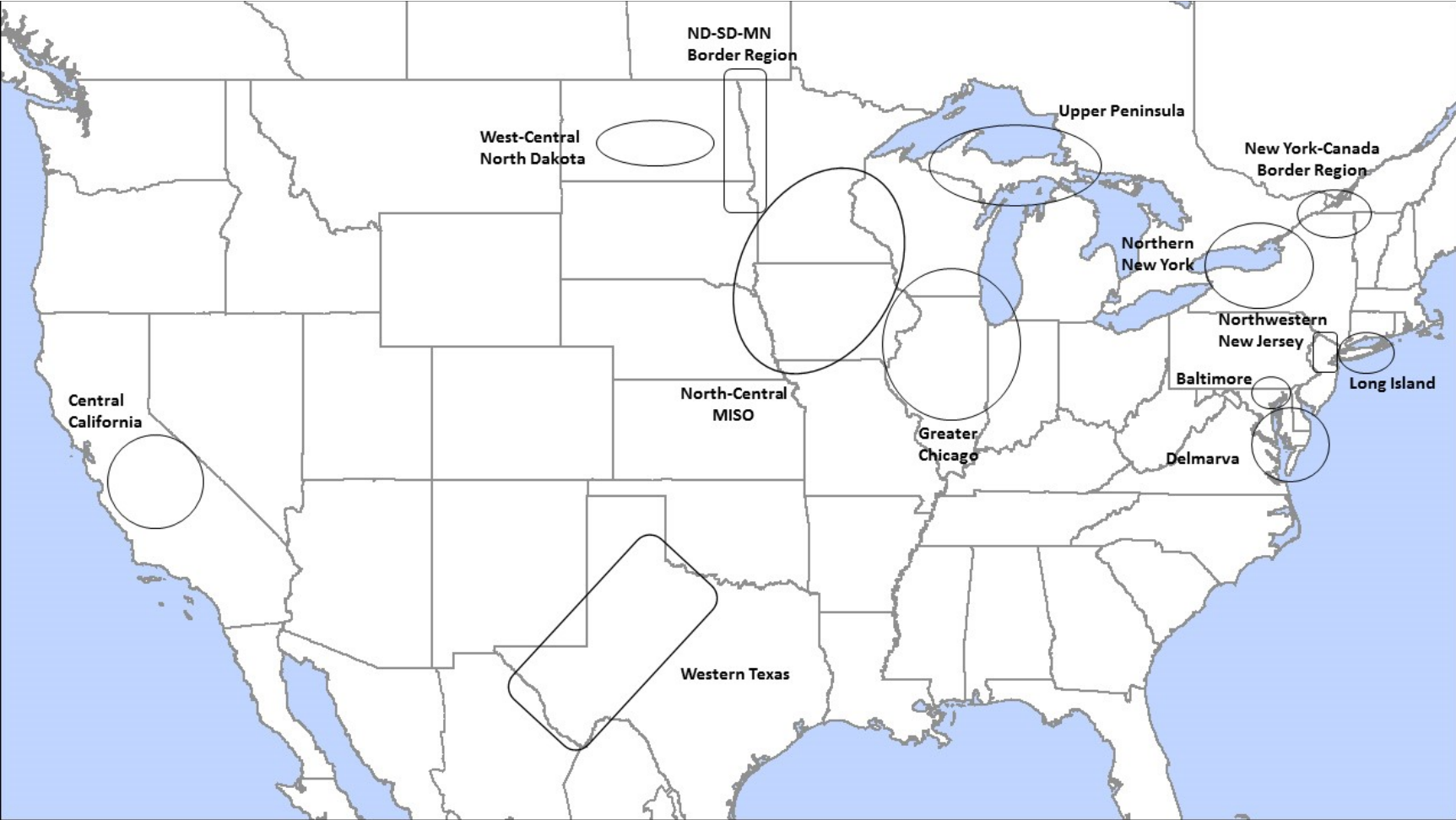
Figure 8
Summary of RTO Market Price Differential Metric for Select Areas

Area Identified by Staff	RTO/ISO	Price Direction	Start of Area's Longest Occurrence of Ongoing Price Differentials ⁷⁰	Metric (Years of persistence through 2015)
Baltimore	PJM	High	2005	11
Upper Peninsula	MISO	High	2005	11
North-Central MISO	MISO	Low	2005	11
		High	2005	11
Delmarva	PJM	High	2006	10
New York-Canada Border Region	NYISO	Low	2006	10
Northern New York	NYISO	Low	2006	10
Northwestern New Jersey	PJM	High	2007	9
Greater Chicago	PJM	Low	2007	9
		High	2012	4
Long Island	NYISO	High	2009	7
Western Texas	SPP	Low	2010	6
		High	2010	6
West-Central North Dakota	MISO	Low	2010	6
ND-SD-MN Border Region	MISO	Low	2010	6
Central California	CAISO	High	2013	3

Source: Staff analysis of ABB Velocity Suite price data from 2000 through 2015 and SPP price data between 2014 and 2015.

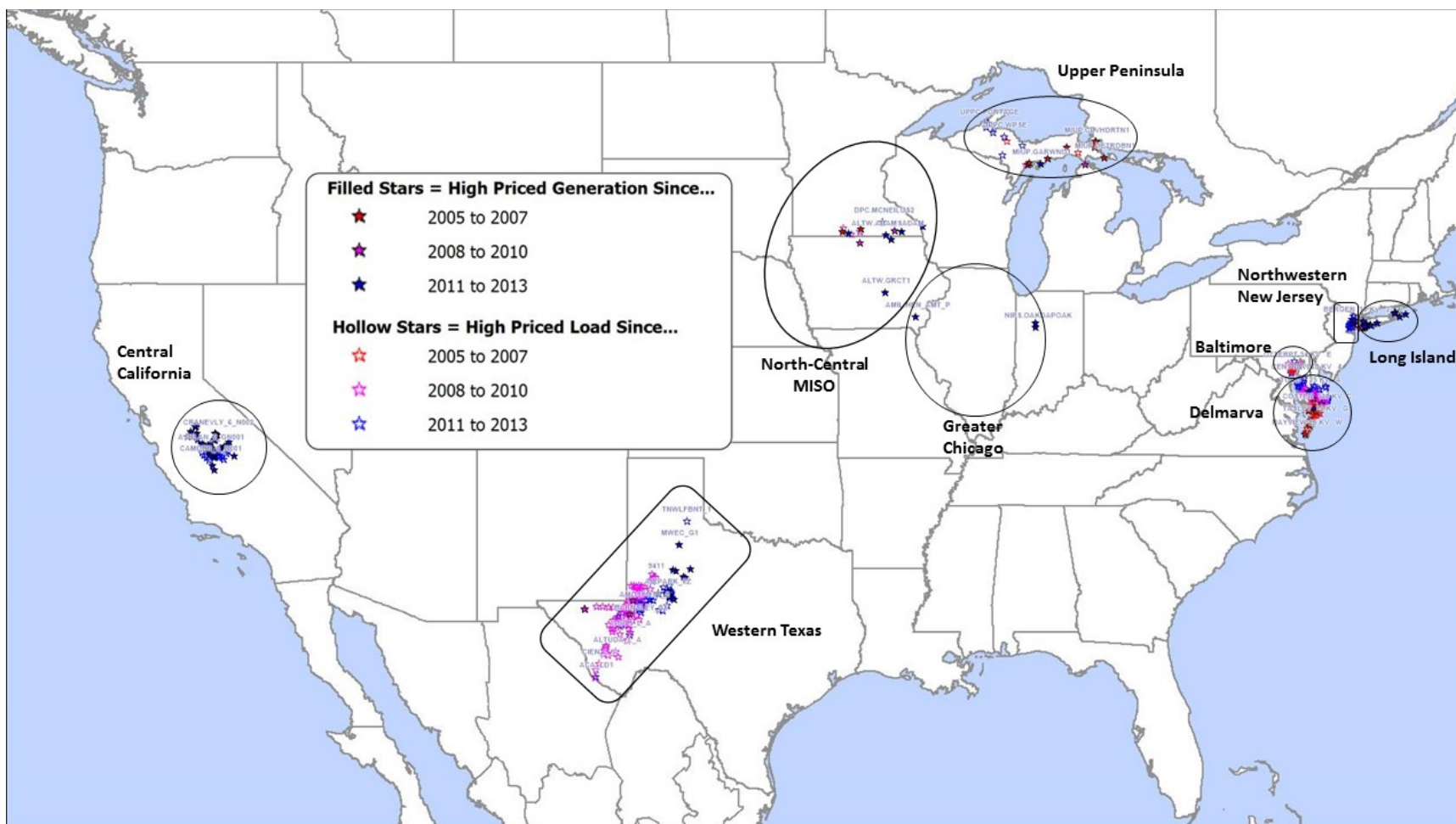
⁷⁰ Not all points in each area have experienced the persistent occurrence of high or low prices for the same period of time; this column shows the initial years of persistent price differences based on the longest-standing, persistent occurrence of high or low prices in the area.

Figure 9
Regions with High-Priced or Low-Priced Points



Sources: Staff analysis of ABB Velocity Suite and SPP price data.

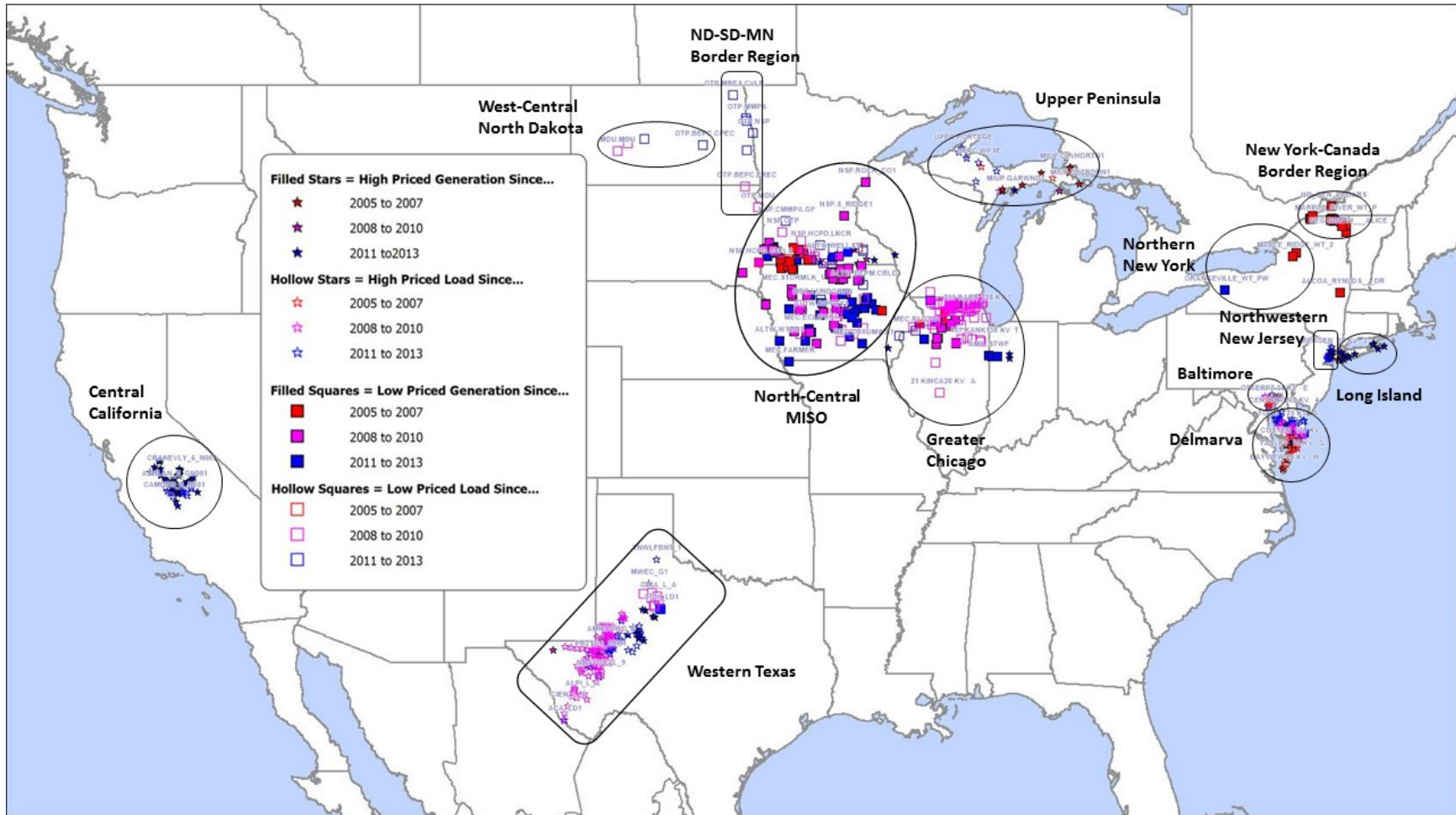
Figure 11⁷²
High-Priced Points



Sources: Staff analysis of ABB Velocity Suite and SPP price data.

⁷² The years in which the persistently high prices began were grouped into three categories: 2005 to 2007, 2008 to 2010, and 2011 to 2013.

Figure 12
High-Priced and Low-Priced Points



Sources: Staff analysis of ABB Velocity Suite and SPP price data.

Of note, in reviewing the 2015 data, staff found that SPP is experiencing fewer persistent price differentials than staff observed in the past. In the 2016 Report, staff identified a large number of low-price points in an area called Western SPP, which included central to western Iowa, Kansas, and Oklahoma, as well as the northern Texas Panhandle. Many of those low-price points disappeared when staff calculated the metric for the 2017 Report, falling from 554 points in the 2016 Report to two points in the 2017 Report. Staff credits the decrease in low-price points to several changes impacting the region, including significant transmission investment in the region in 2014 (as indicated in the section below on the Baseline Metric), SPP's implementation of the Integrated Marketplace in March 2014, and SPP's consolidation of its former 16 balancing authorities into one consolidated balancing authority in 2014.

The difference between the total number of high- and low-price points in the 2016 Report (1,986) and the 2017 Report (1,482) does not exactly equal the change in the number of points in SPP (552 points), as some new points outside of SPP were designated as high- or low-price points, thus pushing the total number of points higher.

Caveats

While staff found its analysis of persistent price differentials informative, there are limitations to this analysis. First, there may be reasons other than insufficient transmission capacity why high or low prices persistently occur in a particular case. For example, a state may have a renewable portfolio standard that only counts in-state resources toward compliance, thus requiring the use of potentially more expensive local resources no matter how much transmission capacity may be available to access lower cost resources elsewhere. Second, even if more transmission capacity could reduce the deviation of price from the market average in a particular case, if the cost of the needed transmission upgrade would exceed this benefit, it might not be beneficial to undertake such an upgrade. Finally, lines connecting points where high prices occurred to points where low prices occurred might not help equilibrate prices as much as might be expected based only on this analysis. For example, the high prices and the low prices may not occur at the same time of the year.

III. Metrics to Permit Baseline Analyses of the Impacts of Policy Changes

The third category of metrics includes three interrelated metrics: (1) load-weighted transmission investment; (2) load-weighted circuit-miles; and (3) load-weighted circuit-miles per million dollars of investment. Given the caveats associated with each metric, as discussed below, they are best analyzed as a group to provide an indication as to whether transmission investment is both sufficient and cost-effective. In combination, these three metrics allow for a comparison of how much transmission infrastructure has been developed in each North American Electric Reliability Corporation (NERC) region of the U.S. and the relative cost of that investment.⁷³

LOAD-WEIGHTED TRANSMISSION INVESTMENT (INCREMENTAL)

Background

This metric describes the load-weighted dollar value of transmission facilities added (i.e., that went into operation) each year between 2008 and 2015 in the eight NERC regions of the contiguous U.S.⁷⁴ Weighting transmission investment dollars by the associated retail load allows for comparisons between entities of different sizes (as measured by the amount of retail load).⁷⁵ While more load-weighted investment may not always be better than less load-weighted investment, tracking how these values adjust to changes in Commission policy may be informative.

Methodology

Staff used transmission project data broken out by NERC region from the C Three Group's North American Electric Transmission Projects database.⁷⁶ Investment dollars represent the nominal cost or reported budget for each project. To aid comparison across years, staff

⁷³ The metrics in this section of the 2017 Report focus on NERC regions instead of transmission planning regions because staff's data source, C Three Group, reports transmission investment by NERC region rather than transmission planning region. Moreover, staff utilizes NERC net energy for load values to weight the transmission investment and circuit-miles data, and NERC reports such net energy for load data based on its eight regions.

⁷⁴ The eight NERC regions include FRCC; MRO; Northeast Power Coordinating Council (NPCC); Reliability First Corporation (RFC); SERC Reliability Corporation (SERC); SPP; Texas Regional Entity (TRE); and Western Electricity Coordinating Council (WECC).

⁷⁵ As with other load-weighted metrics in this paper, staff uses NERC "net energy for load" data for retail load.

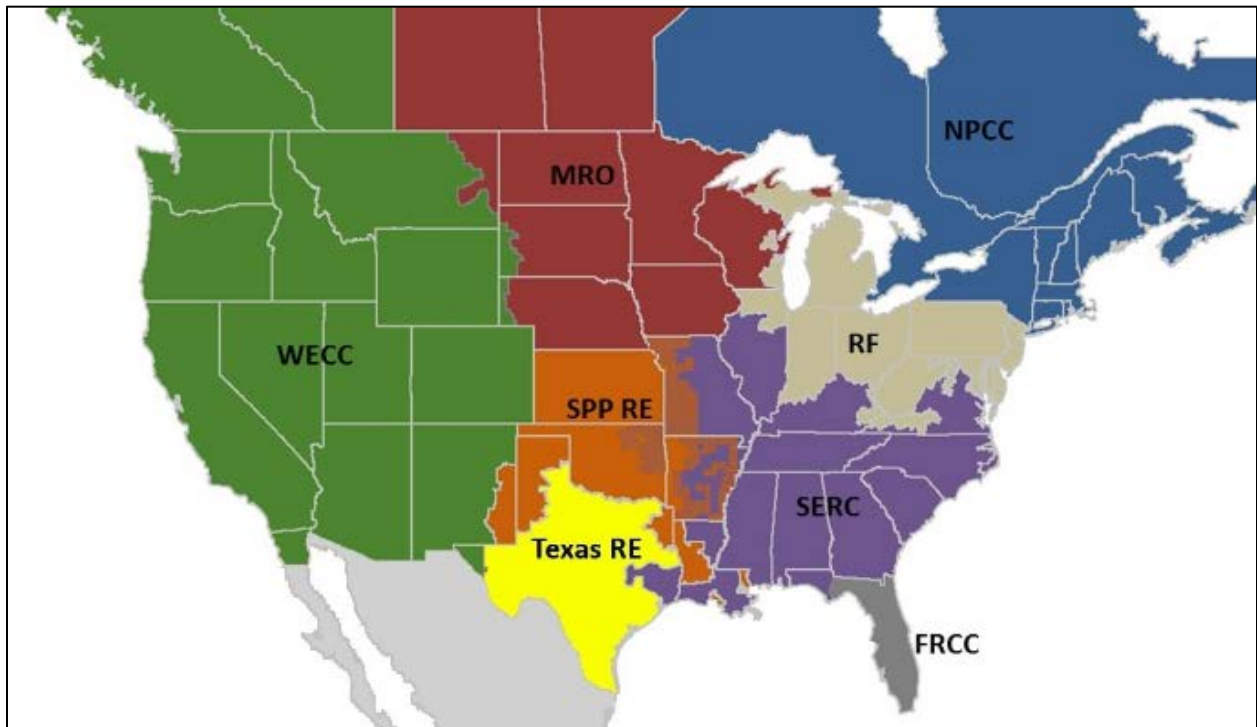
⁷⁶ C Three Group reports continuously updated information on more than 17,000 69 kilovolt (kV) through 765 kV transmission projects in the U.S., Canada, and Mexico. See <https://www.cthree.net/transmission/database/default.aspx>.

converted the values to 2015 dollars using the annual average of the consumer price index for all urban consumers (CPI-U).⁷⁷ To calculate the final, load-weighted metric, staff divided the normalized investment figures for each NERC region for each year by the net energy for load in each year, as reported in NERC’s 2015 Electricity Supply & Demand (ES&D) database.

Staff chose 2008 as the first year of the analysis due to a lack of robust project data across all NERC regions prior to that year. Staff excluded a limited number of projects without a NERC region designation or with multiple designations.

Figure 13 shows the footprints of the eight NERC regions.

Figure 13
NERC Regions Map



Source: NERC.

⁷⁷ In the absence of an industry standard for calculating changes in the prices of goods associated with transmission investment, CPI-U was chosen as a broad measure of changes in prices over time. See Bureau of Labor Statistics (BLS), CPI Detailed Report – August 2016, Table 24 (annual average), <http://www.bls.gov/cpi/cpid1508.pdf>.

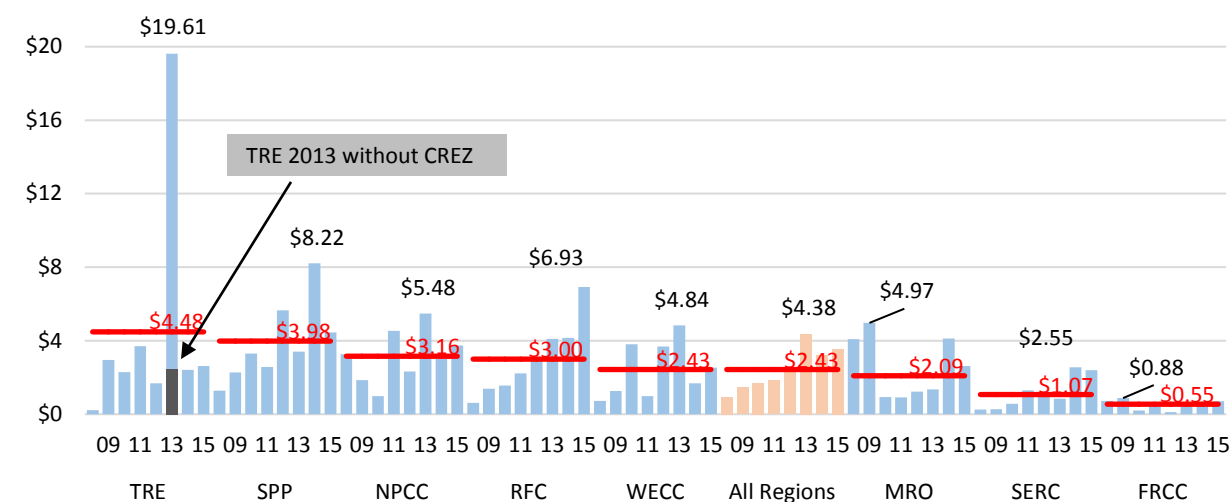
Results and Analysis

Staff identified 9,754 projects that went into operation between 2008 and 2015, representing approximately \$77 billion (in 2015 dollars) of incremental transmission investment.

Approximately three-quarters of this total (\$58 billion) was invested in projects primarily involving new and upgraded transmission lines, with the remaining quarter (\$18.7 billion) invested in projects involving substations and other non-line facilities.⁷⁸

Figure 14 shows the load-weighted incremental transmission investment (in dollars per MWh) in the eight NERC regions of the contiguous U.S. from 2008 to 2015. The values in red represent the regional average load-weighted investment across all eight years, while the values in black refer to the highest load-weighted dollar investment in each region over the time period.

Figure 14
Incremental Load-Weighted Transmission Investment in the U.S., 2008-2015
 All New and Upgraded Projects in Operation, \$/MWh



Sources: C Three Group, NERC, and BLS.

Overall, the average load-weighted transmission investment for all regions over all eight years is \$2.43 per MWh of load, although staff found investments “lumpy” in most regions, as is typical for large infrastructure projects. Due to a major spike in transmission investment in 2013, the average load-weighted investment in TRE over all of the years exceeds \$4.00 per MWh. Six of

⁷⁸ The project types in the C Three Group database are not completely binary (i.e., line vs. non-line projects); some projects involve both new or upgraded lines and associated new or upgraded substations. For the purpose of this metric, if a project involved a line component, then staff categorized it as a line project. Thus, staff included upgrades to address sag, clearance, or thermal issues as line projects. If no line-related component existed in a given project, then staff categorized the project as a non-line project.

the eight NERC regions (SPP, NPCC, RFC, WECC, MRO and SERC) are in the range of approximately \$1.00 per MWh to \$4.00 per MWh on average over the period, while one region without an organized market (i.e., FRCC) fell below \$1.00 per MWh on average over the period. On a regional level, the metric shows an uneven trend of load-weighted investment over the time period.

Compared to the 2016 Report, the average load-weighted investment per MWh over all of the NERC regions in the 2017 Report rose \$0.24 per MWh. With another year of data, RFC has a higher average load-weighted investment per MWh than WECC in the 2017 Report, but otherwise, the relative positions of the regions remain the same. In the 2016 Report, WECC and RFC had an average load-weighted investment per MWh of \$2.61 and \$2.34, respectively, between the years 2008 and 2014. In the 2017 Report, RFC and WECC had an average load-weighted investment of \$3.00 and \$2.43, respectively, between the years 2008 and 2015. Compared to some other NERC regions, RFC had large absolute and load-weighted investments in 2013 and 2014, which then jumped to \$6.93 per MWh in 2015—a total of approximately \$8.8 billion over the three years—due to several large projects that came into operation. Those projects included the merchant-owned Hudson Transmission Project, an underground and underwater HVDC line from New Jersey to Manhattan,⁷⁹ and a number of projects in PSEG's service territory.

As described in the 2016 Report, staff lists here the projects that contributed to the peak years of investment in certain NERC regions. TRE had the highest all-year average load-weighted investment over the period (\$4.48 per MWh) and highest single-year metric (\$19.61 per MWh in 2013) due to the approximately \$6.5 billion of projects — the largest single-year investment of any region — that went into operation in 2013. Of the \$6.5 billion, approximately \$5.7 billion was under Texas' Competitive Renewable Energy Zone (CREZ) initiative, which aimed to alleviate congestion and integrate wind capacity into the electric grid.⁸⁰ In SPP, the relatively large investment in 2014 represents the completion of several balanced portfolio projects and priority projects proposed under the region's highway/byway initiative. The first phase of priority projects under this initiative was estimated to cost \$1.14 billion; several of the projects went into operation in 2014,⁸¹ as did several of the balanced portfolio projects.⁸² In NPCC, the Greater Springfield Reliability Project and Rhode Island Reliability Projects—both portions of the New England East-West Solution group of projects⁸³—began operating in 2013. In WECC, portions of the Tehachapi Renewable Transmission Project and Energy Gateway Transmission Expansion Project were completed in 2013, and the Sunrise Powerlink — a \$1.9 billion project

⁷⁹ See <http://hudsonproject.com/project/>.

⁸⁰ The Competitive Renewable Energy Zone initiative was established by Texas State legislation in 2005. All initiative projects were complete by January 30, 2014, at a total cost of \$6.9 billion. See Lasher (ERCOT), "The Competitive Renewable Energy Zone Process," presentation to DOE's Quadrennial Energy Task Force, August 11, 2014, http://energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf.

⁸¹ SPP, "SPP Approves Construction of New Electric Transmission Infrastructure to Bring \$3.7 Billion in Regional Benefits," (April 27, 2010 Press Release), [http://www.spp.org/publications/Priority Projects Approved 4-27-10.pdf](http://www.spp.org/publications/Priority%20Projects%20Approved%204-27-10.pdf).

⁸² SPP, "Balanced Portfolio," <http://www.spp.org/engineering/transmission-planning/balanced-portfolio/>.

⁸³ Northeast Utilities, "New England East-West Solution (NEEWS)," <http://www.transmission-nu.com/residential/projects/news/>.

designed to, among other things, deliver renewable energy from the Imperial Valley to maintain reliability and meet state and federal energy policy goals⁸⁴ — was completed in 2012. MRO had its largest absolute transmission investment of \$1.7 billion in 2014, when several portions of the CAPX2020 projects⁸⁵ came into operation.

Caveats

Staff notes that there are important caveats with respect to the implications of this metric. First, as mentioned above, more investment in transmission is not necessarily better in all cases. For example, entities whose loads are located near their generation resources may be able to serve load with less transmission investment than similarly sized entities with more dispersed loads. Second, the costs of constructing transmission facilities may vary by region such that a project meant to address an identified need may cost more in one region than it would in another. In such case, the total transmission investment in the higher-cost region will be higher, but not because that region has constructed more transmission infrastructure.

LOAD-WEIGHTED CIRCUIT-MILES (INCREMENTAL)

Background

This metric describes the load-weighted circuit-miles of transmission lines added between 2008 and 2015 in the eight NERC regions. As with the earlier metric, weighting transmission circuit-miles by the associated retail load allows for comparisons between entities of different sizes.

Methodology

For this metric, staff filtered the C Three Group database by project type and status, removing those projects that do not include a line component (e.g., that involve only a substation upgrade) and those that were not operating during the seven-year period from 2008 to 2015.⁸⁶ Staff excluded a limited number of projects without a NERC region designation or with multiple regional designations.

To determine the number of circuit-miles for each project, staff multiplied the reported line miles by the number of reported circuits. In cases where the number of circuits was not reported, staff assumed that the line has only one circuit. While this may underestimate the

⁸⁴ CPUC, *Decision Granting A Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project*, Application 06-08-010, http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/95357.htm.

⁸⁵ See <http://www.capx2020.com/index.html>. These projects were undertaken to ensure the electricity reliability of Minnesota and the surrounding region – North Dakota (ND), South Dakota (SD), and Wisconsin (WI). The individual projects included several 345 kV transmission lines (all points are in Minnesota, unless otherwise noted): Bemidji-Grand Rapids; Big Stone South (SD)-Brookings County (SD); Brookings County (SD)-Hampton; Fargo (ND)-St Cloud; Hampton-Rochester-La Crosse (WI); and Monticello-St. Cloud.

⁸⁶ Based on projects in the C Three Group North American Electric Transmission Project Database as of August 20, 2016.

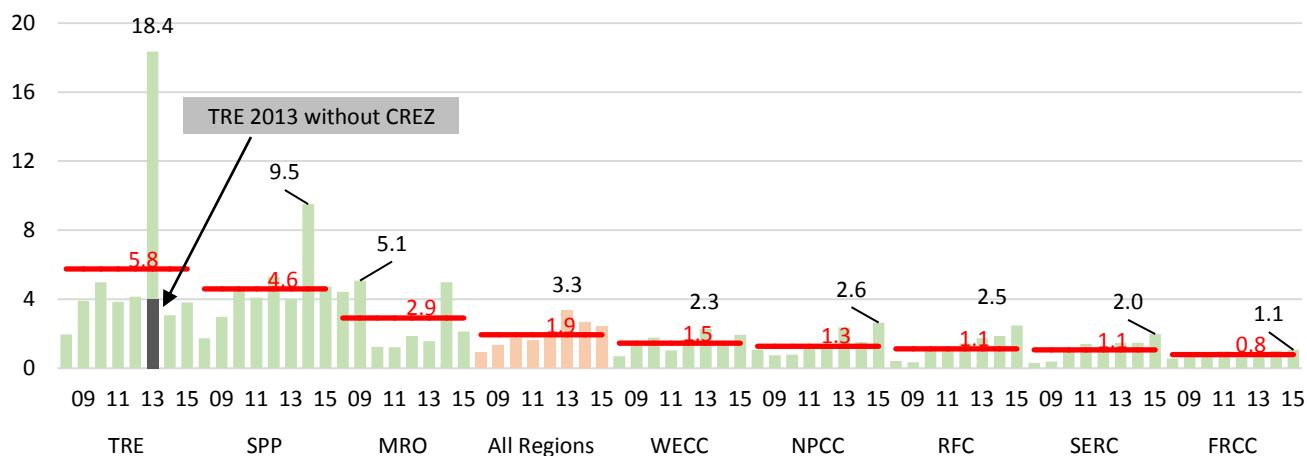
number of actual number of circuit-miles for those particular projects, staff believes this is an appropriately conservative assumption. Staff then summed the circuit-miles of all of the projects reported in each NERC region to determine the total number of circuit-miles added in each region in each of the years in question.

To arrive at the final load-weighted circuit-miles metric for a given NERC region, staff divided the annual circuit-miles value for the NERC region by the corresponding net energy for load in that region in the same year.

Results and Analysis

Figure 15 shows the load-weighted transmission line additions (in circuit-miles per TWh) in the eight NERC regions of the contiguous U.S. from 2008 to 2015. The values in red represent the eight-year regional average, while the values in black refer to the highest load-weighted circuit-miles in each region. The 4,788 projects in the sample represent a total of 62,789 circuit-miles of transmission facilities added over the period from 2008 to 2015.

Figure 15
Load-Weighted Circuit-Miles of Transmission Added in U.S., 2008-2015
 New and Upgraded Lines in Operation, Circuit-Miles/TWh



Sources: C Three Group and NERC.

Overall, the results for this metric are similar to those presented in the 2016 Report. TRE and SPP lead while SERC and FRCC lag behind the other regions in terms of load-weighted circuit-miles added, with five regions (WECC, NPCC, RFC, SERC, and FRCC) below the all-region average of 1.9 load-weighted circuit-miles per TWh. In the 2017 Report, however, the average number of load-weighted circuit-miles per TWh is slightly higher for TRE and MRO (between

0.1 and 0.3 circuit-miles per TWh) than in the 2016 Report. The period average for SPP rose substantially from 3.4 load-weighted circuit-miles per TWh in the 2016 report to 4.6 circuit-miles per TWh in the 2017 Report. Load-weighted circuit-mile investment in WECC fell 0.3 circuit-miles per TWh between the 2016 Report and the 2017 Report.⁸⁷

As noted in the 2016 Report, the relative positions of some of the regions differ from those reported in the overall investment metric because of regional differences in investments in projects with long line components versus shorter line projects or projects without line components.

Caveats

This metric helps to address some of the concerns with the Load-Weighted Transmission Investment metric because it does not consider the cost of transmission infrastructure, which, as explained above, may differ by region. However, the usefulness of this metric also is limited in that it does not account for geographic variations among the regions. For example, in regions where loads are located far away from generation points, there may be a greater need for transmission investment in those regions as compared to regions where loads are located relatively close to generation points.

LOAD-WEIGHTED CIRCUIT-MILES PER MILLION DOLLARS OF INVESTMENT

Methodology

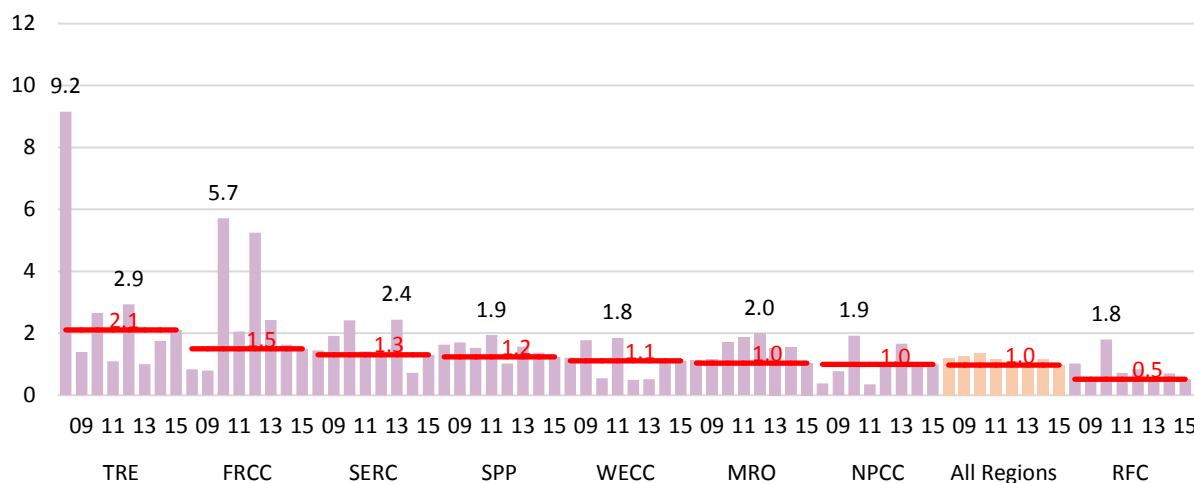
This metric is designed to provide a basis for assessing the cost impact of different policy choices or factual circumstances on transmission investment. Specifically, this metric divides the load-weighted circuit-miles of transmission lines added in the U.S. between 2008 and 2015 by the amount of money invested over the same time period (in million dollars of investment normalized to 2015 dollars). Staff also took the data for this metric from NERC's database and C Three Group's transmission database. Staff used the sample of 4,788 projects that have line components and filtered the data, as described in the previous metric.

Results and Analysis

Figure 16 shows the number of load-weighted circuit-miles per million dollars of transmission investment (in 2015 dollars) in the eight NERC regions of the contiguous U.S. from 2008 to 2015. The values in red represent the eight-year regional average, while the values in black refer to the highest circuit-miles per million dollars of investment in each region.

⁸⁷ The variations in the results between the 2016 and 2017 Reports for the NERC regions are due to corrections in the data – in the 2016 Report, staff inadvertently matched the circuit-miles data for a given year with the forecasted NERC net energy for load data instead of the actual values.

Figure 16
Load-Weighted Circuit-Miles
Added per Million Dollars of Investment, 2008-2015
New and Upgraded Lines in Operation, Circuit-Miles/\$ Million



Sources: C Three Group, NERC, and BLS.

Regions with higher values represent areas with greater numbers of load-weighted circuit-miles added per million dollars invested. By this measure, TRE and FRCC, on average, built the most load-weighted circuit-miles per million dollars of investment across all of the years (at least 1.5 load-weighted circuit-miles per million dollars), compared to an average of 1.0 load-weighted circuit miles per million dollars of investment for all regions combined. RFC built the fewest load-weighted circuit-miles per million dollars across all years – approximately 0.5 load-weighted circuit-miles for every million dollars invested. The difference in load-weighted circuit-miles per million dollars invested may be due to a range of factors, including terrain, population density, and state policy choices, among others, though staff notes that regions investing in more substation projects or other project types with zero to no circuit miles have lower load-weighted circuit miles added per million dollars invested.

The results shown here are dramatically different from those reported in the 2016 Report. For example, for the years 2008 to 2014, as reported in the 2016 Report, MRO built, on average, the most load-weighted circuit-miles per million dollars of investment at 1.7, followed by FRCC at 1.6. The average load-weighted circuit-miles per million dollars of investment across all regions during that period was similar to the value reported in the 2017 Report. However, during that time period, NPCC, WECC, and RFC had even lower average load-weighted circuit-miles per million dollars of investment at 0.8 or less.

The relative load-weighted circuit-miles added per million dollars of investment in the various regions changed in the 2017 Report, in part, based on the share of investment that is attributed

to projects without line components. For example, MRO allocated 25 percent to 45 percent of its investment dollars to projects without a line component between 2008 and 2014. In 2015, the most recent year for which data is available, 50 percent of MRO's transmission infrastructure investment was on projects without a line component. That higher spending on non-line projects caused MRO's circuit-miles added per million dollars of investment to be lower than in some other regions in 2015. TRE, in contrast, allocated more investment dollars to projects with a line component in 2015, thus causing its load-weighted circuit-miles added per million dollars of investment relative to that of other regions to jump. Another reason that may explain the change in the relative load-weighted circuit-miles added per million dollars of investment for the various NERC regions from the 2016 Report to the 2017 Report is that both C Three and NERC occasionally revise their historical data. Staff highlights the case of MRO, because it went from having the highest average load-weighted circuit-miles added per million dollars of investment in the 2016 Report to having the third lowest average load-weighted circuit-miles added per million dollars of investment in the 2017 Report. A major change in MRO was the circuit-miles per million dollars of investment in 2013. For the 2016 Report, the analysis included C Three's count of 280 projects that went into service in MRO in 2013. As of the preparation of the 2017 Report, C Three had revised this count down to only 214 projects in MRO that went into service in 2013, while the corresponding NERC net energy for load figure increased substantially from 584,125 gigawatt hours (GWh) to 692,434 GWh. Those two differences likely explain much of the large drop in MRO's load-weighted circuit-miles per million dollars of investment in 2013 – 2.9 in the 2016 Report to about 1.5 in the 2017 Report. The large change, combined with the bigger investment in non-line projects in 2015, lowered MRO's average load-weighted circuit-miles per million dollars of investment between 2008 and 2015.

Caveats

Gauging the cost-effectiveness of different transmission investments may be difficult because much of the cost of a project is driven by the highly variable physical and regulatory challenges particular to each region, project, and/or developer. For example, an upgrade to an existing transmission facility is likely to cost less than a greenfield facility. Likewise, a transmission facility that is to be located in a population-dense or environmentally-sensitive area may involve higher costs per circuit-mile. To the extent that these challenges are more prevalent in some regions than others, they are likely to affect the cost-effectiveness analysis.

To at least partially address these concerns while aiding comparison, staff grouped the eight years of data by region and calculated an average across the years. Staff grouped by NERC region under the assumption that most of these regions are large enough to encompass both areas where transmission investment would be expensive on a per-mile basis as well as areas where such investment would be relatively cheaper on a per-mile basis.

IV. Conclusion

In updating the 2016 Report, staff has gained more knowledge of the state of transmission investment in the U.S. With respect to the first category of metrics, which assess nonincumbent participation in competitive transmission development processes, staff concludes that in those transmission planning regions that have held competitive proposal windows, nonincumbent participation has generally been robust. With respect to the second category of metrics, which evaluate whether appropriate levels of transmission infrastructure exist, staff concludes that, at least in certain areas of the U.S., transmission investment is reducing persistent congestion. Finally, with respect to the third category of metrics, which allow for the analysis of the impact of policy changes, staff finds that the results did not change significantly from the 2016 Report. Staff summarizes its observations in greater detail below.

Transmission Investment Metrics	
Metric	New Findings in the 2017 Report
Metrics to Assess Participation of Nonincumbent Transmission Developers in Regional Transmission Planning Processes	
Percentage of Nonincumbent Transmission Project Bids or Proposals	Nonincumbent proposals accounted for 47 percent of all proposals submitted in CAISO's, PJM's, NYISO's, and MISO's competitive transmission development processes between 2013 and 2016. In CAISO and MISO, nonincumbent proposals accounted for the majority of proposals submitted. In PJM, nonincumbents submitted more proposals than incumbents in three out of four years. In 2015, NYISO received more proposals from nonincumbents, but the reverse was true in 2016. Staff could not discern the share of incumbent versus nonincumbent proposals in SPP in 2015 because SPP masked the identities of the transmission developers that submitted proposals.
Number of Unique Developers Submitting Proposals (New Metric for 2017 Report)	While PJM received a high number of proposals each year, the number of unique developers was comparatively low (7 to 22 entities annually). The other transmission planning regions (CASIO, NYISO, and MISO) had numbers of unique developers that were roughly equivalent to the number of proposals received. Due to the masking of developers' identities in SPP, staff could not determine the number of unique developers in that transmission planning region.
Number and Percentage of Selected Nonincumbent Proposals (New Metric for 2017 Report)	Overall, 20 percent of the proposals selected in 2013 were nonincumbent proposals, 6 percent of the proposals selected in 2014 were nonincumbent proposals, 3 percent of the proposals selected in 2015 were nonincumbent proposals, and none of the proposals selected in 2016 were nonincumbent proposals. CAISO had the largest increase in nonincumbents' share of selected proposals, increasing from zero percent in 2013 to 100 percent in 2015. PJM selected the largest number of proposals, but it selected only one nonincumbent proposal over four years. MISO and SPP each selected an incumbent proposal in their single competitive transmission

	development process. As of the preparation of this report, NYISO has yet to select a proposal.
Stakeholder Participation in Regional Transmission Planning Processes (New Metric for 2017 Report)	Stakeholder attendance at regional transmission planning meetings during FY2015 and FY2016 was relatively stable in both RTOs and non-RTOs. Most of the increases or decreases that staff found during this time were not dramatic. An encouraging finding is that, as envisioned by Order No. 1000, nonincumbents are participating in stakeholder meetings, with staff finding increases in nonincumbents’ levels of participation in four of the twelve transmission planning regions.
Metric to Indicate Whether Appropriate Levels of Transmission Infrastructure Exist	
RTO/ISO Market Price Differential	Relatively high or low real-time LMPs (relative to high or low prices that prevailed in the Commission-jurisdictional RTO/ISO market) occurred persistently (i.e., for at least two years) at 1,482 generator or load points since 2005.
Metrics to Permit Baseline Analyses of the Impacts of Policy Changes	
Load-weighted Transmission Investment (Incremental)	Load-weighted transmission investment averages over all NERC regions for all years was over \$2.00 per MWh of retail load, although investments are “lumpy” for most regions, as is typical for large infrastructure projects. Staff identified the largest load-weighted investments in TRE, exceeding \$4.00 per MWh of retail load across all years. Staff found the smallest load-weighted investments (below \$1.00 per MWh of retail load over all years) in FRCC.
Load-weighted Circuit-miles (Incremental)	The findings are similar to the load-weighted transmission investment metric.
Load-Weighted Circuit-miles per Million Dollars of Investment (Incremental)	TRE has the highest load-weighted circuit-miles per million dollars of transmission investment across all years (2.1), compared to an average of 1.0 load-weighted circuit-miles per million dollars of transmission investment for all NERC regions. RFC has the lowest load-weighted circuit-miles per million dollars of transmission investment across all years – 0.5 circuit-miles for every million dollars of transmission investment.