HOW TRANSMISSION PLANNING & COST ALLOCATION PROCESSES ARE INHIBITING WIND & SOLAR DEVELOPMENT IN SPP, MISO, & PJM

Prepared for:

American Council on Renewable Energy (ACORE), in coordination with the American Clean Power Association and the Solar Energy Industries Association

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Table of Contents

Table of Appendices

Acknowledgement and Disclaimer

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Lastly, we thank the key stakeholders that have participated in interviews that have served to form the basis of this report. We have kept the names of our interviewees confidential to preserve the candid nature of the interviews.

Disclaimer

This Report is substantially based on the candid representations made by key market participants and stakeholders in SPP, MISO, and PJM electric markets, through a series of interviews, conducted in this study. The interviews explored how current transmission planning and cost allocation processes impede renewable energy development in SPP, MISO, and PJM. Concentric has relayed the material content of those interviews in this report. Though we have made every effort to vet and corroborate the information we received in the interviews, the authors cannot attest, endorse, warrant, or assume responsibility for the accuracy or reliability of interview statements received from respondents, which are conveyed in this report. Conclusions reached in this report are the product of those interviews and do not necessarily represent the opinions of Concentric Energy Advisors, Inc.

Glossary

ACEG	Americans for a Clean Energy Grid
ACORE	American Council on Renewable Energy
ACP	American Clean Power Association
Affected System	The negative effect, due to technical or operational limits being exceeded, that compromises the safety and reliability of a neighboring electric system
APC	Adjusted Production Cost
ARR	Auction Revenue Right (SPP)
ATTR	Annual Transmission Revenue Requirement
B/C	Benefit-to-Cost Ratio
Backbone Transmission Capacity	High voltage transmission capacity (generally 345 kV and above)
Cluster	Group of generators seeking interconnection in the same general area of electric grid
CREZ	Competitive Renewable Energy Zones
CSP	Coordinated System Plan
FERC or Commission	Federal Energy Regulatory Commission
Futures	Planning model forecast scenarios
GIA	Generator Interconnection Agreement
GIP	Generator Interconnection Process
HVDC	High Voltage Transmission Lines
IMEP	Interregional Market Efficiency Project
Incumbent Transmission Owner	Transmission owner that is an electric utility
Intertie	A line or system of lines permitting the flow of electricity between major systems
IRP	Integrated Resource Plan
ISO	Independent System Operator
ITP	Integrated Transmission Plan (SPP)
JOA	Joint Operating Agreement
JRPC	Joint RTO Planning Committee
Load Serving Entity	The entity that supplies electricity to a customer (the electric utility)
LRS	Load Ratio Share (SPP)
MEP	Market Efficiency Project
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Plan

MVP	Multi-Value Project
NERC	North American Electric Reliability Corporation
NERC TPL Standards	NERC Transmission System Planning Performance Requirements
Network Upgrade	Necessary transmission expansion or reinforcement of electric system to create sufficient transmission capacity to accommodate a generator's request to interconnect
NYSERDA	New York State Energy Research and Development Authority
Order 1000	FERC Issued Order 1000
PJM	PJM Interconnection
PUCT	Public Utility Commission of Texas
Rate Pancaking	Rate pancaking occurs when electricity is scheduled across more than one transmission providers' borders and each provider assesses full or partial transmission charges that results in duplicate transmission fees
RIIA	Renewable Integration Impact Assessment (MISO)
Right Sizing	Upgrade and Raise the Voltage
ROFR	Right of First Refusal
RPS	Renewable Portfolio Standards
RTEP	Regional Transmission Expansion Plan (PJM)
RTO	Regional Transmission Organization
Seams	RTO boundaries
SEIA	Solar Energy Industries Association
SPP	Southwest Power Pool
TO	Transmission Owner
Transmission Customer	Entity that may execute a transmission service agreement (interconnecting generators and load-serving entities)
Transmission Owner	Entity that owns and maintains transmission facilities

Executive Summary

Concentric was engaged by the American Council on Renewable Energy ("ACORE"), in coordination with the American Clean Power Association ("ACP")[1] and the Solar Energy Industries Association ("SEIA") to produce a Report, based on interviews with industry stakeholders to investigate the extent to which transmission planning processes in the Midcontinent Independent System Operator ("MISO"), the Southwest Power Pool ("SPP"), and the PJM Interconnection ("PJM") have deficiencies that are resulting in the under-development of cost-competitive renewable energy projects. This report outlines transmission planning processes in these three regions and presents insights from market participants based on their recent experiences with these processes. This report summarizes deficiencies in Regional Transmission Organization ("RTO") planning processes that were identified by market participants in each of the RTOs as well as possible remedies.

MAJOR FINDINGS:

- **Centrally coordinated regional transmission planning needed**
- **Interregional planning requires aligned models and methodologies**
- **Future scenarios need to better reflect expected renewable energy demand and growth**
- **Transmission benefit metrics should be expanded and standardized**
- **Resource zone identification would help optimize planning, facilitate competition, and benefit consumers**
- **Planning models should better reflect the likely dispatch of resources and technologies**
- **Fairly allocating costs of new transmission among beneficiaries requires greater scrutiny or wholesale reform**

The availability of backbone transmission capacity (generally 345 kV and above) is essential to the efficient and least cost deployment of U.S. solar and wind resources. Renewable generation has grown exponentially over the last decade and is expected to continue its ascent as state renewable standards and policies increasingly limit carbon dioxide and methane emissions from electric generation resources. Fifteen U.S. states and territories have adopted mandates to achieve 100 percent carbon-free renewable energy – with some as early as 2030.[2] Beyond state clean energy mandates, electric utilities have also made their own clean energy commitments, and corporate buyers are increasingly making voluntary commitments to purchase renewable energy. The rapid cost declines of utility-scale wind and solar (and projections that those cost declines will continue) often make these resources the least-cost new power option.[3] Moreover, the U.S. Energy Information Administration projects that solar energy, wind energy, and battery storage will comprise 80 percent of the new capacity installed in 2021.[4] Together, these factors suggest that renewable energy will be the principal source of electric generation in the future. Yet, existing transmission planning processes have been insufficient in preparing the electric grid for this future resource mix. Transmission construction involves long lead times, typically between 7

1 ACP was formerly known as the American Wind Energy Association.

2 DSIRE, Renewable & Clean Energy Standards, available at https://s3.amazonaws.com/ncsolarcen-prod/wp-content/uploads/2020/09/RPS-CES-Sept2020.pdf. States and territories with 100% clean and renewable energy goals include (WA by 2045, CA by 2045, HI by 2045, NV by 2050, CO by 2050, NM by 2045, PR by 2050, WI by 2050, VA by 2045/2050, DC by 2032, NY by 2040, ME by 2050, RI by 2030, CT by 2040, and NJ by 2050).

3 See, e.g. Lazard, Levelized Cost of Energy Analysis (LCOE 14.0), available at https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2020/.

4 U.S. Energy Information Administration, Today in Energy, January 11, 2021, available at https://www.eia.gov/todayinenergy/detail.php?id=46416.

and 10 years, and the window may be closing to develop the needed transmission expansion to enable optimization of clean energy, meet state clean energy objectives, and other "voluntary" demand for low-cost renewable energy.

The focus of transmission planning processes in SPP, MISO, and PJM has been on developing solutions to meet the current reliability and economic needs of the system. Those processes were not designed to identify the necessary transmission expansion to enable future renewable energy development. Transmission development in recent years has primarily focused on reliability and low voltage projects, the majority of which fall outside regional planning processes, and the needed backbone transmission development has been essentially stalled. In most RTOs, local reliability planning, performed by the load serving transmission owners, occurs outside regional reliability planning processes and serves only as an input to baseline regional reliability planning models.[5] According to a recent Americans for a Clean Energy Grid ("ACEG") report, annual regionally planned transmission investment is declining, while total annual transmission investment remains relatively robust,[6] suggesting that transmission constructed outside regional planning processes, such as local reliability planning, has been increasing. The report goes on to state that between 2013 and 2017, "about one-half of the approximately $70 billion of aggregate transmission investments by FERC-jurisdictional transmission owners in ISO/RTO regions [was] approved outside the regional planning processes…"[7]

The effects of this lack of transmission planning for the future generation resource mix is plainly visible in the generator interconnection queues where prospective generators are confronted with extremely high network upgrade costs to interconnect to the transmission system – sometimes in the hundreds of millions of dollars.[8] High network upgrade costs and cost uncertainty in the generator interconnection queues have resulted in bottlenecks and significant delays (in some cases as long as 4 years) that have prevented hundreds[9] of renewable energy projects from reaching commercial operation. There were 734 GW of proposed generators waiting in interconnection queues nationwide at the end of 2019, almost 90 percent of which were renewable and storage resources.[10]

The current cost allocation practice for interconnecting generation projects in MISO, SPP, and PJM is that interconnecting generators are considered to be the "cost causers" and bear most, if not all, of the network upgrade costs even if other transmission customers or load may benefit from the upgrade. Generator interconnection cost allocation practices were addressed in FERC Order No. 2003, which established a default rule that network upgrade costs that are "at or beyond" the point of interconnection would initially be paid by the

5 Note that in SPP local reliability is addressed in the regional process, except for Xcel's Southwestern Public Service Co., which continues to engage in local reliability transmission planning.

6 Rob Gramlich and Jay Caspary, Americans for a Clean Energy Grid and Macro Grid Initiative, Planning for the future: FERC's opportunity to spur more cost-effective transmission infrastructure (2021) at 26. [hereinafter Gramlich and Caspary, Planning for the future].

7 Ibid. fn 34. Johannes P. Pfeifenberger et al., Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value (April 2019) at 6-7.

8 Peder Mewis and Kelley Welf, Clarion Call! Success has Brought Us to the Limits of the Current Transmission System, available at https://www.cleanenergyeconomymn.org/blog/clarion-call-success-has-brought-us-limits-current-transmission-system (November 12, 2019).

9 John Moore, New Analysis: Midwest and Southern Leaders are Letting Crucial Clean Energy Projects Slip Away, available at https://sustainableferc.org/new-analysis-midwest-and-southern-leaders-are-letting-crucial-clean-energy-projects-slip-away/ (November 23, 2020) [hereinafter Moore, Leaders Letting Clean Energy Slip Away]; see also, Sustainable FERC, New Interactive Map Shows Clean Energy Projects Withdrawn from the MISO Queue, available at https://sustainableferc.org/wp-content/uploads/2020/08/MISO-Queue-Map-and-Analysis-2PageReport-8-26-20-2.pdf. [hereinafter Sustainable FERC, Projects Withdrawn from MISO Queue].

10 Gramlich and Caspary, Planning for the future, supra note 6, at 24.

interconnecting generator.[11] Accordingly, generators in the interconnection process are looking for the most cost-effective point of interconnection.

The cost of network upgrades assigned to interconnecting generators has been a major factor contributing to projects withdrawing from the interconnection queues.[12] In PJM only 15 percent of projects in the generator interconnection queue successfully make it through the queue.[13] Projects that are withdrawn trigger a need to restudy the system impacts of the proposed generation remaining in the queue, exacerbating delays in the generator interconnection process. The Sustainable FERC Project reports that 278 clean energy projects were withdrawn from the MISO generator interconnection queue from 2016 – 2020.[14] Over this period more than 30 percent of proposed wind, solar, battery storage, and hybrid solar storage projects that had reached advanced stages in the MISO queue were withdrawn, equivalent to nearly 35,000 megawatts of clean energy - costing 72,000 jobs.[15]

The problems in the generator interconnection process have also led to the understatement of renewable forecast scenarios, or "Futures," in the regional transmission planning models since RTO transmission planners often consider only future generation that has secured an executed generator interconnection agreement for inclusion in baseline transmission planning models. Though alternate Futures cases may be considered in additional planning scenarios, these Futures assumptions often continue to underestimate future renewable generation.

Additionally, planning models do not reflect the network upgrades that are contemplated to be assigned in the generator interconnection process when there is not an executed generator interconnection agreement. There is a disconnect between the transmission planning and the generator interconnection process, where a generator may be assigned a network upgrade that is later identified through the transmission planning process. The planning process also does not analyze the need for solutions in the timeframe necessary to serve the needs of future renewable generators. The result is gridlock. Generators are unable to move through the queues without more transmission capacity, but the need for new transmission capacity identified in RTO planning processes somewhat depends on the generators' ability to move through the queues and secure signed interconnection

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11 See FERC Order 2003 (July 24, 2003) at PP. 21-22. It is interesting to note Order No. 2003, which promulgated regulations that govern the generator interconnection process, makes clear that it did not contemplate that network upgrade costs would be entirely borne by interconnecting generators with no certainty of recouping those costs over a reasonable period of time, as is current day practice. The FERC stated, "Regarding pricing for a non-independent Transmission Provider, the distinction between Interconnection Facilities and Network Upgrades is important because Interconnection Facilities will be paid for solely by the Interconnection Customer, and while Network Upgrades will be funded initially by the Interconnection Customer (unless the Transmission Provider elects to fund them), the Interconnection Customer would then be entitled to a cash equivalent refund (i.e., credit) equal to the total amount paid for the Network Upgrades, including any tax gross-up or other tax-related payments. The refund would be paid to the Interconnection Customer on a dollar-for-dollar basis, as credits against the Interconnection Customer's payments for transmission services, with the full amount to be refunded, with interest within five years of the Commercial Operation Date." [footnote references omitted]. However, many ISOs have adopted a participant funding approach which assigns most network upgrade costs to interconnecting generators.

12 Delays and withdrawn projects from interconnection queues are also the result of generators engaging in various forms of price discovery in interconnection queues, e.g., entering various capacity sizes for the same project to determine which can be built economically per the interconnection study, or generators entering the queue without sufficient commitment or security (i.e., permits, land acquisition), generators remaining in the queue in hopes that the network upgrade they need will be built while they are in the queue either through transmission planning processes or network upgrades built by another generator (or cluster of generators). All of these practices lead to more gridlock in the interconnection queues, more projects dropping out of the queues and the more frequent need to restudy the queues. Increased cost certainty as generators enter the queues would help alleviate some of the unnecessary congestion in the generator interconnection process.

13 Chocarro. (2020, December 11). RWE Renewables Americas Input [Slides]. PJM Generation Interconnection Workshop #2. https://www.pjm.com/-/media/committees-groups/committees/pc/2020/20201211-workshop-2/20201211-item-03t-iker-chocarro-rwe-pjm-interconnection-workshop.ashx, Slide 4.

14 Moore, Leaders Letting Clean Energy Slip Away, supra note 9; see also, Sustainable FERC, Projects Withdrawn from MISO Queue, supra note 9.

15 Ibid.

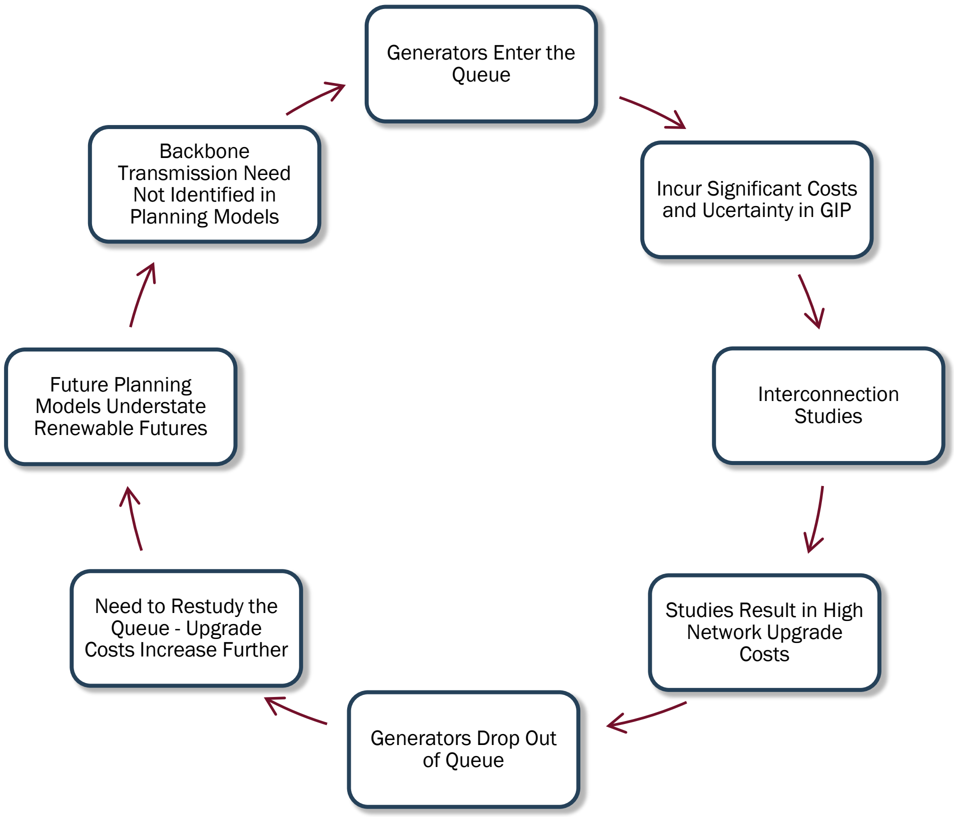
agreements. This disconnect is one contributing factor to the persistent and overly conservative forecasts of renewable resource expansion in transmission planning models and the inability of planning models to identify the necessary transmission expansion for future renewable generation.

As a result, transmission planning has been occurring haphazardly through piecemeal transmission projects and on the backs of interconnecting generators through network upgrades assigned in the generator interconnection process. Neither process looks to future co-optimization of transmission and renewable generation development, but focuses primarily on how to solve reliability, congestion, and interconnection issues at least cost. This fragmented approach to transmission development cannot be expected to provide either an efficient or a least cost solution for the transmission needed to accommodate the level of renewables required to meet public policy objectives and consumer demand, or importantly, a future vision of an efficient, affordable, and reliable transmission grid. Transmission planning to enable renewable resources is currently trapped in a negative feedback loop that must be broken for the necessary enabling transmission expansion to be constructed.

Important and encouraging steps have been undertaken by the RTOs to address some of these issues. MISO and SPP have engaged in a joint planning process to facilitate interregional development. MISO has undertaken a Renewable Integration Impact Assessment (RIIA) to better understand the impacts of renewable energy growth in the region over the long term, identify renewable integration issues, and examine potential solutions to mitigate them to manage expected renewable penetration levels in MISO. MISO recently issued its final RIIA report after a multiple-year study, which has been well received by clean energy sector organizations.[16] SPP has established a new task force to work on concepts of optimizing generator interconnection processes, planning, transmission service, and local planning; and PJM is engaging stakeholder workshops to understand the problems in its planning processes and the interconnection queue. Nevertheless, we find ourselves in a loop that cannot bring about the needed transmission until reforms are enacted.

16 Beth Soholt. (2021, March 4). MISO's RIIA Study is a Great Start to Prepare for the Generation Shift to More Renewables CleanGridAlliance.Org. https://cleangridalliance.org/blog/145/misos-riia-study-is-a-great-start-to-prepare-for-the-generation-shift-to-more-renewables. Principal among the report's findings were that in order to achieve 50 percent renewable energy on the MISO system: (1) more flexible resources will be needed, as well as market products and incentives for existing and future gas and storage and even renewables to offer their flexibility; (2) more transmission and other emerging technologies will be needed to provide a stable grid capable of delivering power where it is needed; and (3) the region needs to move forward expeditiously to address these issues in a timely manner.

Figure 1: Negative Feedback Loop of Transmission Planning and Generator Interconnection Processes



Major Findings

"Centrally coordinated" planning at the interregional and RTO levels is needed to identify the geographic areas where untapped renewable energy resources exist and develop optimal and cost-efficient paths for transmission infrastructure development to deliver low-cost renewable resources to load centers.

Centrally coordinated planning should incorporate realistic estimates of future renewable energy production and provide for advanced technology solutions where appropriate. Ideally, an effective centrally coordinated planning framework would employ a unified planning model for interregional transmission planning, would integrate and/or coordinate interregional, regional, local, and generator interconnection planning processes; and would consider the system holistically for optimal, cost effective performance when selecting solutions. Indeed, this would require a "grand bargain" among stakeholders to achieve a fully integrated, holistic, fully optimized, centrally coordinated planning approach. If such a model is beyond immediate reach, the following substantial components would each individually serve to improve the transmission planning processes and allow constrained renewable energy development to move forward.

Interregional transmission planning should rely on either a unified national interregional planning model or regional models that have sufficiently aligned planning objectives, assumptions, benefit metrics, and cost allocation methodologies to properly assess benefits and costs of interregional transmission projects.

Joint planning between RTOs has been largely ineffective and has not resulted in the necessary interregional transmission projects to export renewable resources across RTO seams. Market participants have voiced concerns over the use of separate RTO planning models that rely on different and often incompatible assumptions, benefit calculations, and cost allocation methodologies across RTOs and the extent to which they hinder interregional transmission development. Lack of alignment in planning models has led to the inability of interregional projects to pass each RTOs' benefit-to-cost analysis. Interview respondents were in favor of harmonizing planning models to eliminate modeling disparities. Some advocated for a national policy for interregional development.

Reasonable expectations of renewable resource expansion should be integrated into "Futures" assumptions in transmission planning studies. This should include reasonable forecasts for future storage, renewables and gas generation additions, as well as fossil fuel plant retirements.

Interview respondents overwhelmingly cited the persistent under-forecasting of renewable energy resources in the alternative Futures assumptions used in planning models to be a significant obstacle to transmission development. The issue is partly due to the rapid expansion of renewable generation outpacing even the most aggressive transmission planning Futures forecasts, and partly due to the inclusion of only planned generation that has secured firm interconnection commitments in baseline planning models. As such, planning models are not identifying the transmission needs of future generation in their baseline models. When RTOs do provide for high renewable Futures scenarios, the assumptions used have not kept pace with actual renewable development. Interview respondents emphasized the need to plan proactively and look beyond projects with executed interconnection agreements to third party projections of renewable development for baseline planning models.

Benefit metrics used to assess the comparable benefit of projects relative to their costs should be expanded and standardized across regions to the extent possible.

Most RTOs rely on some form of adjusted production cost savings ("APC") savings to evaluate project benefits, but standard APC savings calculations do not capture the full range of benefits of any given modern-day transmission project. Interview respondents were mixed on how to incorporate an expanded set of benefits into the benefit-to-cost assessments and the project selection framework. Responses ranged from the formulation of an all-inclusive benefit-to-cost metric, to expanding the APC calculation to include only additional benefits that are easily identified and quantified, to leaving the APC metric as is and considering other benefits outside the APC metric. For purposes of interregional transmission development, most agreed that benefit metrics should be standardized between RTOs to facilitate interregional transmission development along the RTO seams.

Planning models and/or processes should better reflect the expected real-time operations and economic dispatch of generation resources.

Several market participants voiced concerns over the ability of legacy transmission planning models to identify transmission solutions that reflect the likely dispatch of resources. Legacy planning models were developed to accommodate large central station baseload generation and electric systems and have traditionally been built to withstand "worst case" events, based on a fairly rigid set of deterministic conditions. Some reliability planning models dispatch generation resources based on firm transmission service to legacy generation units versus the economic dispatch that RTOs use to dispatch resources in real time. Planning models currently in use lack the sophistication and flexibility to accurately capture the specific characteristics of renewable resources and their probabilistic dispatch given weather conditions, or to identify opportunities to optimize geographically diverse resources through transmission solutions. Planning models should attempt to model the likely dispatch of resources and accurately capture resource characteristics, based on a market-based simulation in planning, where possible. Doing so would result in APC metrics that better reflect actual and expected market operation and dispatch.

Competitive processes would benefit from more coordinated planning where resource zones are identified, and infrastructure solutions that address optimal paths to market are solicited.

Competitive processes, as they exist today, lead to very little transmission grid expansion. Transmission owners and most RTOs have focused almost exclusively on local or reliability projects with short time frames. Most RTOs have held very few competitive solicitations. According to the previously referenced ACEG report, "relatively little has been built to meet the broader regional and interregional economic and public policy needs envisioned when FERC issued Order 1000 ("Order 1000"). Instead, most of these transmission investments addressed reliability and local needs."[17] Interview responses were mixed on how best to address competition, but many pointed to the Competitive Renewable Energy Zone ("CREZ") initiative in Texas as a beneficial model of a successful competitive process that provided a coordinated assessment and simultaneous solicitations of generation and transmission.

[17] Gramlich and Caspary, Planning for the future, supra note 6, at 26, fn 34.

Cost allocation for generator interconnection upgrades should be shared with load or other interconnecting generators based on a fair allocation of benefits.

Many renewable project developers commented that they cannot access the MISO, SPP, and PJM markets because of the high cost of network upgrades necessary for interconnection. Many of the upgrades benefit load as well as the interconnecting generator, but there is not a standardized methodology across RTOs for allocating costs of the upgrades required for generator interconnections to load.[18] Currently, in each RTO the generator is charged for all or nearly all of the upgrade even though the upgrade will have benefits to other generators or load.[19] Though most market participants agree that generators should have some share of network upgrade costs to connect, the prevailing view was in favor of the development of a more equitable cost sharing methodology.

Overview of Major Challenges

Current regional, local, and interregional planning processes are not designed to identify optimal paths for getting the lowest-cost renewable energy resources to market. If optimization of transmission and low-cost renewable energy development is the goal, it is essential that planning reforms are implemented, emphasizing centrally coordinated and integrated planning processes to identify the cost-effective, backbone transmission system expansion necessary to achieve the renewable energy future set out in state energy plans across the nation. This planning should reflect the expected dispatch and likely interaction between energy resources, capture the full spectrum of benefits that renewable energy resources provide, and provide for an equitable cost sharing methodology between the transmission owners and load.

18 In FERC Order No. 2003, the Commission set a default rule that transmission owners would bear responsibility for the network upgrades, but gave ISOs "flexibility to customize its interconnection procedures and agreements to meet regional needs." See, Ameren Services Co. v. FERC, 880 F.3d 571, 574 (D.C. Cir. 2018).

19 For example, MISO adopted a methodology allocating 90 percent of network upgrades above 345 kV to generation owners, and requiring generation owners to pay 100 percent of such costs for lines below 345 kV.

1. Introduction

Scope of Work

Concentric was engaged by the American Council on Renewable Energy ("ACORE") in coordination with the American Clean Power Association ("ACP") and the Solar Energy Industries Association ("SEIA") to produce a Report that provides a comprehensive review of regional and interregional transmission planning processes in each regional transmission organization ("RTO"), and identifies the key deficiencies in the those planning processes (including models and assumptions, timing and coordination) and cost allocation in and between the Southwest Power Pool ("SPP"), the Midcontinent Independent System Operator ("MISO"), and the PJM Interconnection ("PJM") RTOs.

Study Approach

Concentric drafted the technical portion of this report detailing regional and interregional planning processes in SPP, MISO, and PJM. In addition, Concentric conducted candid interviews with key industry stakeholders to identify the specific deficiencies in the regional and interregional transmission planning processes in each RTO that are inhibiting new wind and solar development and contributing to the uneconomic curtailment of wind and solar generation, as well as potential solutions to those issues.

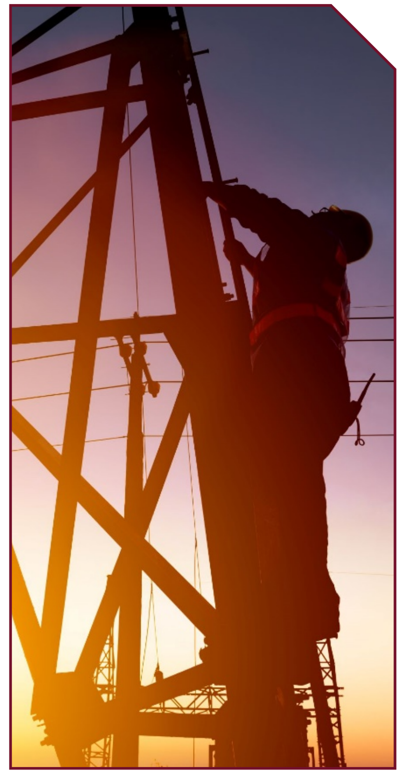
Concentric conducted 20 confidential interviews with individuals representing key market participants, of which 4 were investor-owned utilities active in transmission development and renewable energy development; 2 were consultants specializing in electric transmission; 1 was an infrastructure developer (renewable energy and transmission); 9 were renewable energy developers; 2 were transmission developers, and 2 were clean energy organizations. The interview questions covered the following topics: (1) the primary impediments to wind and solar development; (2) benefit metrics used to identify and rank transmission projects in the regional transmission planning process; (3) the generator interconnection process; (4) planning models; (5) interregional transmission development; (6) other issues; and (7) best practices for regional transmission planning. A copy of the interview questions is provided in Appendix A to this report.

Organization of This Report

The remainder of this report is organized in two primary sections. Section 2 provides an overview of regional transmission planning processes, the generator interconnection process, and the interregional planning processes. (A detailed review of the RTO planning processes for SPP, MISO, and PJM is included in Appendix B; and a detailed review of interregional planning processes is included in Appendix C.) Section 3 details the primary deficiencies and potential solutions that were identified in our interviews, organized by major finding. The content of this Section was drawn from interview responses and conveys candid stakeholder observations and suggestions for improvement expressed in the interviews.

2. Overview of Transmission Planning & Generator Interconnection Processes

Regulatory Background



As a general matter, transmission investments broadly fall into three categories: (1) projects needed to maintain local reliability, including efforts to maintain or upgrade existing facilities; (2) expansions of the regional transmission system developed through the regional transmission planning process that addresses reliability, economic, or public policy needs; and (3) network upgrades identified through the generator interconnection process that are required to interconnect planned generation or satisfy long-term firm transmission service requests.

This background section summarizes the regional transmission planning processes of MISO, SPP, and PJM. These wholesale electric markets are operated by independent system operators or regional transmission organizations (referred to jointly herein as "ISOs" or "RTOs"). The regional transmission planning processes in MISO, SPP, and PJM are regulated by the Federal Energy Regulatory Commission ("FERC" or the "Commission").

FERC issued Order 1000 in 2011,[20] which imposed several requirements on jurisdictional ISO regional transmission planning processes. At a high level, the Order 1000 requirements, among other things, govern the development of the ISO's regional transmission plan, the types of transmission needs considered (reliability, economic efficiency, and public policy), the types of projects and solutions considered (including those proposed by non-incumbent transmission owners), how certain projects are selected for inclusion in the regional plan for purposes of regional cost allocation, and how the costs of projects selected through the regional transmission plans are regionally allocated to ISO sub-regions or zones.[21] Order 1000 also required ISO regional transmission planning processes to consider alternative "non-transmission" solutions along with transmission solutions to address transmission needs, improve coordination and planning activities with neighboring transmission planning regions, and develop a regional transmission process with a method to allocate the cost of new interregional transmission projects that are located across neighboring transmission planning regions. It is notable that Order 1000 did not require interregional planning across neighboring regions, but only interregional coordination.

Regional Transmission Planning

Projects needed to maintain reliability constitute a major portion of the projects selected through regional transmission plans. For example, the most recent MISO transmission plan notes that reliability projects, including age and condition upgrades, are "a vital part" of MISO's regional transmission plan and "account for the majority

20 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 136 FERC ¶ 61,051 (July 21, 2011) ("Order 1000"); Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 139 FERC ¶ 61,132 (May 17, 2012) ("Order 1000-A"); and Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 141 FERC ¶ 61,044 (October 18, 2012) ("Order 1000-B").

21 For example, Order 1000 identified six cost allocation principles.

of all recommended projects."[22] Given their importance, a reliability assessment to identify needed reliability upgrades tends to serve as the foundation of all regional transmission planning processes.

As described further below, this is the case in MISO, SPP, and PJM. All three regional planning processes begin with a reliability model designed to identify and determine a means to resolve any violations of North American Electric Reliability Corporation ("NERC") reliability requirements or applicable regional or local reliability requirements. These reliability models generally underpin the regional planning process. While regional and local reliability requirements differ across the U.S., all ISOs apply the NERC "Transmission System Planning Performance Requirements," often referred to as "TPL standards." These standards require transmission planners to assess the long-term reliability of the planning region, plan for the resource adequacy of specific loads, assess the long-term reliability of interconnected transmission, and establish transmission system planning performance requirements.[23] ISOs similarly model various system contingencies to satisfy the NERC TPL standards.[24]

Any NERC TPL standards that are violated in the reliability planning studies, which are studied under various load conditions, must be addressed with a Corrective Action Plan. The reliability planning models typically study each contingency category as part of one or more steady-state analyses. A steady-state contingency analysis considers the impact that a new system element (either transmission or generation) could have on the system (e.g., specific transmission lines, transformer loadings, etc.). The reliability planning studies also involve a short-circuit analysis. NERC standards require all facilities to be within normal operating ratings for normal system conditions and within emergency ratings after a contingency. The models specify a range for "normal" system conditions and "emergency" operating conditions in the event of a contingency. Finally, the reliability models also include simulations of the system under normal or "intact conditions" where facilities are modeled at their normal ratings and voltage limits, and under "contingent conditions," where facilities are monitored to determine whether they stay within their emergency limits in the event of a contingency.[25]

The transmission owners ("TOs") within the RTO generally have their own local planning requirements and processes that are incorporated into the RTO's regional planning process. The relationship between the local and regional reliability processes varies across the three RTOs. MISO and PJM have distinct local and regional reliability planning processes, with local transmission plans frequently serving as an input to the regional reliability planning process. In contrast, SPP, except for Southwestern Public Service Company, addresses both local and regional reliability needs within a single planning process.

Economic and Public Policy Planning Process

Once the reliability needs have been addressed in the planning process, economic and policy needs are considered. Selected reliability projects typically serve as inputs to the economic and public policy-driven planning process, though some RTOs (e.g., SPP) have a process to consolidate or co-optimize reliability projects that may also address an economic need.

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22 MISO, 2020 MTEP, https://www.misoenergy.org/planning/planning/mtep20/.

23 FERC, Report on Barriers and Opportunities for High Voltage Transmission (June 2020) at 25.

24 The NERC TPL-001-04 contingencies are as follows: P0: No Contingency; P1: Single Contingency; P2: Single Contingency (bus section); P3: Multiple Contingency; P4: Multiple Contingency (fault plus stuck breaker); P5: Multiple Contingency (fault plus relay failure to operate); P6: Multiple Contingency (two overlapping singles); P7: Multiple Contingency (common structure).

25 See e.g., MISO Transmission Planning Business Practices Manual BPM-020-r22, Section 4.3.2 ("MISO Transmission Planning Manual").

In economic and public policy planning processes, RTOs will consider a number of Futures scenarios that are intended to capture the range of potential fleet changes and conditions that may exist over the long term (typically the next 10 to 20 years). Futures scenarios will also consider alternate load forecasts (i.e., electrification of the transportation fleet, energy efficiency, distributed generation, regional demand, and energy projections). They may also project changing emissions constraints. Projections of the generation fleet and the size and location of system loads are important because these factors drive the transmission needs identified.

Unlike reliability projects, which are typically selected based on "least cost," economic and public planning projects are selected based on the highest benefit-to-cost ("B/C") ratio. Various benefits may be used to assess the extent to which candidate projects satisfy the identified needs. The plans generally rank the projects, or sets of projects, that are the most cost effective or those with the highest B/C ratio. The candidate projects are then evaluated based on B/C ratios (different benefits may be added together) and the degree to which the solutions meet the identified transmission needs. Only projects that meet the specified B/C ratio thresholds are considered further. Order 1000 regulations require that the B/C ratio used to screen potential projects in the regional plan for regional cost allocation cannot exceed 1.25, meaning that RTOs cannot require proposed projects to be subject to a higher threshold than 1.25.

MISO employs a 1.25 B/C ratio in its economic planning and a 1.0 B/C ratio if a project solves multiple needs. PJM similarly relies on a 1.25 B/C ratio for market efficiency projects, and SPP relies on a B/C ratio of 1.0 or above for economic planning and public policy projects. The planning process then evaluates the project portfolio as a whole and selects a final set of recommended projects for the transmission plan. This final, comprehensive evaluation may eliminate certain projects and/or combine projects to eliminate redundancies or co-optimize projects.

For detailed information on the regional transmission planning processes of MISO, SPP, and PJM, please see Appendix B.

Generator Interconnection Process

Transmission system upgrades required to interconnect new generation are a key driver of transmission investment. The cost and type of the upgrades required for new generator interconnections are determined and allocated to new generators through the RTO's generator interconnection process. As discussed further in Section 3, the interaction between the generator interconnection process and the regional transmission planning process in MISO, SPP, and PJM is somewhat limited.

Each RTO generally identifies the transmission upgrades required for a given group of generators seeking interconnection (referred to as a "cluster") through studies conducted in the generator interconnection process. In MISO, SPP, and PJM, as well as other RTOs, the generator interconnection process is a separate process that proceeds on separate timelines and uses different models and assumptions from the transmission planning models. As discussed further in Section 3, the generator interconnection process often identifies significant and costly upgrades to the transmission system. With few exceptions, these costs are directly assigned to the interconnecting generators.

The costs of transmission projects identified in the local and regional reliability transmission planning processes are allocated to system loads within each RTO zone pursuant to the FERC-approved cost allocation methodology. The baseline regional transmission planning model used for reliability planning typically incorporates known adjustments to the system, i.e., only the transmission upgrades associated with the generator interconnection process that planned generation resources have agreed to pay for (e.g., through an executed Interconnection agreement with associated cost responsibility). Though regional economic and public policy planning processes do rely on Futures scenarios that go beyond firm interconnection commitments, those processes are separate and on different timelines than the generator interconnection process. It is not infrequent that generators may be assigned large network upgrades that would later be identified as an economic or reliability project in a subsequent planning iteration. Given that the generator interconnection and regional transmission planning processes proceed on largely separate tracks, there is little to no joint optimization of transmission projects that facilitate interconnections for new generation and transmission projects that meet the reliability, economic, and/or public policy needs of system loads. Without this joint optimization, there is also no means to jointly assess the benefits and allocate the costs of projects that yield benefits to both system loads and new generation.

Interregional Projects

As noted above, Order 1000 requires MISO, SPP, and PJM to engage in interregional planning. Order 1000 expanded on the planning requirements of Order 890 by requiring each public utility transmission provider to establish procedures with each of its neighboring transmission planning regions, for purposes of coordinating and sharing regional transmission plans, to identify possible interregional transmission facilities that are more efficient and cost effective than separate, regional solutions.[26] Specifically, Order 1000 requires each public utility transmission provider to establish procedures with each of its neighboring transmission planning regions for the purpose of: (1) coordinating and sharing the results of the respective regional transmission plans to identify possible interregional transmission facilities that could address regional transmission needs more efficiently or cost-effectively than separate regional transmission facilities; and (2) jointly evaluating those interregional transmission facilities that the pair of neighboring transmission planning regions identify.[27] Additionally, Order 1000 requires each public utility transmission provider to develop procedures by which differences in data, models, assumptions, transmission planning horizons, and criteria used to study a proposed interregional transmission project can be identified and resolved for purposes of joint evaluation, but left each pair of neighboring regions discretion to implement this requirement.[28]

Order 1000 also requires neighboring planning regions to jointly evaluate interregional projects identified in the interregional studies and jointly allocate the costs of such projects across the ISOs.[29] The six cost allocation principles are: (1) costs must be allocated in a way that is roughly commensurate with benefits; (2) there must be no involuntary cost allocation to non-beneficiaries; (3) a required benefit to cost threshold ratio cannot exceed 1.25; (4) costs must be allocated solely within the transmission planning region (or pair of regions) unless those outside the region (or pair of regions) voluntarily assume costs; (5) there must be a transparent method for determining benefits and identifying beneficiaries; and (6) there may be different methods for different types of transmission facilities.[30] Interregional projects are eligible for interregional cost allocation if they are selected in the regional transmission plan of each ISO.

For detailed information on the interregional planning efforts of MISO, SPP, and PJM, please see Appendix C.

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26 Order No. 1000, at P 398.
27 Order No. 1000-A, at P 493.
28 Order No. 1000, at P 437. See also, Midcontinent Independent System Operator, Inc. Southwest Power Pool, Inc., 168 FERC ¶ 61,018 (July 16, 2019) at P 4.
29 Ibid. at PP 578, 582; Order No 1000-A, at P 522.
30 Order No. 1000 at PP 603, 622-693.

3. Identified Deficiencies in Regional and Interregional Transmission Planning Process and Cost Allocation In and Between the PJM, MISO and SPP Regions - Need for Centrally Coordinated and Fully Integrated Transmission Planning

Interregional

Description of the Issue

A recent study by NREL found that increases in transmission capacity across RTO boundaries or ("seams") would allow for improved balancing of system generation and load with less installed capacity overall.[31] Specifically, "[t]he study shows with increased intercontinental transmission that the system was able to balance generation and load with less total system installed capacity across each of the generation scenarios, due to load and generation diversity, and increased operating flexibility. The results show benefit-to-cost ratios ranging from 1.2 to 2.9, indicating significant value to increasing the transmission capacity between the interconnections and sharing generation resources for all the cost futures studied."[32] The same study reported that presently there are seven high voltage transmission lines ("HVDC") linking the U.S. and the Canadian Eastern and Western Interconnections, enabling 1,320 MW of transfer capability between them, while there is 700,000 MW of generating capacity in the Eastern Interconnection and 250,000 MW in the Western Interconnection. Clearly, opportunities exist to improve transfer capabilities across seams, and the NREL Study suggests these opportunities could provide benefits of up to three times for every dollar spent on the basis of production cost savings alone.[33]

INTERVIEW QUOTE:

"Any time a new transmission project is brought up in stakeholder groups, the load entity voices are too concerned about having too high fixed costs on customers' bills. We have to fight tooth and nail to get transmission approved, even though lots would benefit."
– *Investor-Owned Utility*

Renewable generation can and has become trapped within its respective regions. For example, there are times when SPP has more wind capacity than load, and the RTO currently has significant amounts of new wind projects in its interconnection queue. Because of this trend, SPP will likely not be able to absorb all the wind and is missing opportunities to export the resource to other regions, in part due to a lack of interties on the seams with neighboring regions.

The SPP transmission owners (and their loads) are reluctant to build transmission that will result in costs for interconnecting wind that would ultimately be exported to other regions and the RTOs have resisted transmission costs that have been socialized to the RTO's region for a portfolio of projects in other regions. There must be agreement between the RTOs on the costs and benefits of a given transmission project, and the allocation of costs must be commensurate with the allocation of benefits.

31 NREL, The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study, Journal Article Preprint (October 2020) at 7.
32 Ibid.
33 Ibid. at 1-4.

A key obstacle to integrated interregional planning is that individual states and RTOs use different planning models and have differing views on the costs and benefits of a given transmission project or what the region should look like in terms of grid planning.

INTERVIEW QUOTES:

"Seams issues with affected systems' costs are another big issue. When you have to deal with Affected cost as part of the interconnection process, two RTOs, not just different schedules and timing, but different assumptions, kills billions of dollars worth of renewable development."
– Investor-Owned Utility

"What we are really seeing is the real-world impact of lack of alignment, lack of a joint operating agreement and methodologies."
– Renewable Energy Developer

Interconnection projects may not move forward due to high affected system costs (i.e., the cost of negative impacts on a neighboring RTO's system resulting from a given project); or, projects may not move forward where complications in assessing project benefits arise due to the RTOs' use of different modeling assumptions, all of which limit the approval of regionally beneficial projects. In addition to the current lack of alignment, projects that span seams are subject to rate pancaking which can lead to more expensive transmission costs.[34] All of these issues severely limit the ability of interregional projects to move forward. As a result, there have been very few projects across the seams, which has ultimately impeded renewable development and transactions across markets.

To date very few projects have originated from interregional planning processes between MISO/SPP or MISO/PJM.[35] There have been several other targeted market efficiency projects that have been approved through the MISO/PJM interregional process. However, no interregional projects have been approved to date through the MISO/SPP Coordinated System Plan ("CSP"), though as discussed below, MISO and SPP have announced a joint seams study with a strong focus on addressing interconnection issues in 2020.

Relevant RTO Processes

As indicated above, FERC Order 1000 requires the ISOs to engage in interregional planning. But, FERC left how to implement the Order to each of the ISOs' discretion, such that at present, there is no mandate for centrally coordinated interregional planning or an "overlay study" to determine the optimal interconnection points for interregional renewable integration. As a result, opportunities for efficiencies from intercontinental transmission are being missed. To date, interregional transmission expansion has been virtually non-existent.

The current MISO CSP with SPP looks at current constraints and current generation and tries to develop projects that reduce economic congestion. Each RTO relies on its own Futures assumptions and B/C calculations to make its determination of the cost-effectiveness of a given interregional economic project. Recognizing that opportunities exist for beneficial projects between their respective systems, MISO and SPP announced in September 2020 that they will be conducting a joint study targeting interconnection challenges on the seams.[36] The hope is that the study will identify cost effective and efficient transmission upgrades that will include a simultaneous allocation of benefits and/or costs to both load and interconnection customers. But, coming to an

34 See e.g., SPP, Rate Pancaking and Unreserved Use Study (November 2019), available at https://www.misostates.org/images/stories/Seams_Coordination_Efforts/Market_Monitor_Study_on_Rate_Pancaking.pdf.

35 The recent Bosserman-Trail Creek project came out of the 2018 MISO/PJM Coordinated System Plan ("CSP"). The project would address persistent historical congestion projected to continue on the NIPSCO/AEP seam. See PJM, 2019 RTEP, at 56.

36 MISO. (September 14, 2020). MISO and SPP to conduct Joint Study Targeting Interconnection Challenges [Press release]. https://www.misoenergy.org/about/media-center/miso-and-spp-to-conduct-joint-study-targeting-interconnection-challenges/.

agreed upon cost allocation approach that will share transmission upgrade costs between generators and load will be an immense challenge for the RTOs. The joint study kicked off at the end of 2020 and will operate in parallel with each of the RTOs' planning and interconnection processes.

MISO and PJM completed a long-term Interregional Market Efficiency Project ("IMEP") study in mid-2018. In the IMEP study, PJM and MISO each developed a regional market analysis and identified three congestion drivers along the PJM-MISO seam. PJM and MISO jointly solicited interregional market efficiency proposals through an open competitive window that closed on March 15, 2019. The RTOs received ten interregional proposals that addressed at least one of three mutually identified congestion drivers and calculated their respective regional benefits for determination of the total project benefit. Based on the regional analysis and the total B/C ratio, one interregional project – the Bosserman-Trail Creek project - was recommended by both RTOs, which will address persistent historical congestion projected to continue on the NIPSCO/AEP seam.[37] The project has been approved by the Boards of both RTOs and is expected to move forward.

Though Joint Operating Agreements and Coordinated System Plans are in place between the RTOs to address transmission planning across regional seams, to date those studies have dealt only with existing transmission needs and do not reflect a future vision of the grid.

Proposed Solutions

Interview respondents largely agreed that enhanced centrally coordinated planning either between regions or at a national level would be beneficial. Interregional transmission plans should contemplate where renewable resources exist and develop a least-cost transmission solution to bring needed resources to load. The interstate highway system was discussed as a construct that could also be applied to transmission planning, building high-voltage transmission to efficiently connect renewable resources to load that may be long distances away. It was also observed that interstate highways are developed either through pay-as-you-go tolls or taxpayer funds and cannot be expected to be funded by the first vehicle to use the highway.

A centrally coordinated interregional transmission plan should take a long-term forward view of what the grid should look like in the next 40 to 50 years that co-optimizes transmission and generation costs. One party recommended that FERC play an oversight role for interregional transmission planning or take on the role itself.

Given the potential magnitude of transmission build and spend in the coming decades, there is much to be gained from optimizing transmission across RTOs. All respondents agreed that a wider and more uniform planning process will be required to achieve this optimization.

The recently announced MISO/SPP joint seams study that will be undertaken in 2021 was viewed by many respondents as a welcome sign of progress towards improvement of the interregional planning process. It was suggested that a similar regional and interregional study at regular intervals (approximately every three or four years) would be beneficial so that regions can better understand their interactions and opportunities.

INTERVIEW QUOTE:

"A whole bigger issue is macro grid transmission to cross seams and interconnects. Do we need a new FERC Order to allow a different type of entity to do the macro grid across the RTOs and seams? There is a lot of value there."

– *Investor-Owned Utility*

37 PJM, 2019 RTEP, at 56.

Description of the Issue

At the regional level, there are separate reliability planning and economic planning processes, but there is not a holistic view for the least cost solution for the whole system. Further, several commenters noted that the RTOs and transmission owners provide only transmission solutions, but there should be a more dedicated effort to think about how best to incorporate non-transmission alternatives and grid enhancing technologies, such as dynamic line ratings, power flow controls and advanced sensors, topology optimization, storage as a transmission asset, and other non-transmission alternatives upfront in the planning process. Reliability planning by load serving entities and regional transmission planning typically occur in silos and there is very little visibility from one to the other.[38] The interconnection process is similarly siloed and separate from regional planning. With each siloed process serving as a determinative input into the regional planning process, opportunities to co-optimize processes are missed.

INTERVIEW QUOTE:

"Transmission planners are missing these advanced technologies in their transmission planning processes. They should create a process or criteria to add this into mix of potential solutions."

– *Renewable Energy Developer*

Since Order 1000 eliminated the utilities' Right of First Refusal ("ROFR") for beneficial transmission projects in their service territories, transmission owners have become focused on developing their own local reliability projects and immediate need projects (that are not subject to competition under Order 1000) and occur outside the regional planning process.[39] The utilities' focus on local reliability and immediate need projects in their service territories stems from two primary issues: (1) the utility regulatory model rewards transmission investment with an allowed return on capital invested, and as such, transmission construction by an outside party within the utility's regulated service territory represents a foregone revenue opportunity for the utility; and (2) transmission owners have the ultimate obligation to maintain safety and reliability on their own systems and allowing others to build in their service territory poses some risk to the utility. As a result, utilities do not welcome competition in their service territories. Nonetheless, the utilities' progressing hyper-focus on reliability investment was thought by many interview respondents to be crowding out necessary economic transmission investment and opportunities to integrate and optimize planning at the local and regional level.

Many commented that new transmission projects identified in the regional transmission planning process are met with great opposition by the utility

INTERVIEW QUOTES:

"The more you have local planning requirements that differ from regional reliability and regional planning requirements, you are creating a problem. Give the reliability card to the ISO or RTO, but to further give it to the local planner, you are in a sense giving license to gold plate their systems."

– *Renewable Energy Developer*

"Local planning in RTOs is a black box, projects can be built, that aren't necessarily best for region and quietly rolled into zonal rates."

– *Investor-Owned Utility*

38 That SPP does not have a local planning process that is separate from the regional planning process (except for Southwestern Public Service Co. that plans for local reliability on its system).

39 Gramlich and Caspary, Planning for the future, supra note 6 at 19. As previously noted, 50 percent of utility transmission investment occurred outside of regional planning processes between 2013 - 2017.

load serving entities and it is very difficult to get load serving entities to support new transmission construction.

Further, several interview respondents noted that RTOs are significantly influenced by their member transmission owners and tend to avoid making planning decisions that transmission owners would find detrimental to their interests. As such, incumbent transmission owners, who several respondents believed may be best suited to study and plan the expansion of the transmission system (since costs incurred may be recovered through regulated rates), are for the most part focusing on local reliability outside the regional process or immediate need projects where the ROFR remains intact, avoiding competition and regional scrutiny. This local reliability focus will not expand the transmission grid to deliver the lowest cost renewable resources to load and consumes valuable "head room" in retail electric rates to fund necessary backbone transmission investment, as well as results in less-than-optimal use of transmission corridors.

INTERVIEW QUOTES:

"Transmission owners run the RTOs and put a very heavy thumb on the studies. Have to get the creation of the base case out of their hands, into some public vetting such that the transmission owners can't control it."
– *Renewable Energy Developer*

"We are waiting for generators to fund grid expansion."
– *Renewable Energy Developer*

"Bottom line is we need to be designing a regional system to deliver large amounts of renewables that need to be interconnected."
– *Transmission Developer*

The disconnect between the generator interconnection process and transmission planning processes was noted as one of the primary impediments to renewable development during the interviews. In MISO, PJM, and SPP, generators looking to interconnect are assigned substantial network upgrades, for which they are expected to pay essentially the full cost of the upgrade. It can take as many as four years in PJM and SPP, and slightly less in MISO, to move through the interconnection queue and execute a generator interconnection agreement. Interview respondents suggested that part of the issue may be the disconnected generator interconnection and transmission planning processes. The two processes are on separate tracks and timelines, whereby the meaningful information that the generator interconnection process could provide is seldom available in the time frame needed for the transmission planning process. This is particularly problematic since baseline forecasts in planning models are typically based on signed generator interconnection agreements.

The grid has evolved from locally developed reliability projects and generator interconnection upgrades that have specific objectives and do not consider the holistic benefits to the grid. For example, transmission planning models, particularly reliability studies, focus on the least cost solution, but not the optimal solution. Renewable developers are looking for the cheapest point of interconnection. Because this does not include an analysis of an optimized generation interconnection and transmission planning process, the result is a patchwork approach to grid expansion (largely on the backs of new interconnecting generators) rather than a disciplined, planned system that is based on a long-term view of the transmission system. It was a majority view that an integrated, centrally coordinated planning framework is necessary to jointly optimize the needs of local and regional processes, as well as generator interconnection processes, particularly in light of state renewable energy goals.

Relevant RTO Processes

As previously stated, MISO and PJM have distinct and separate local and regional reliability planning processes, with local transmission plans frequently serving as an input to the regional reliability planning process. SPP, however, (except for Southwestern Public Service Company) addresses both local and regional reliability needs within a single planning process. Further, in MISO, SPP, and PJM, the interaction between the generator interconnection process and the regional transmission planning process is limited. For the most part, in each of the RTOs, there is not a distinct public policy planning process, but the RTOs do incorporate federal, state, and local laws and policy requirements into the Futures scenarios. Further details which are drawn from Appendix B to this Report are included below.

MISO

MISO has distinctly separate local and regional reliability processes and generator interconnection processes. Though local reliability and a certain subset of generator interconnections do factor into regional planning processes as inputs, they are siloed and non-concurrent processes. Ultimately, projects recommended by the MISO Transmission Expansion Plan ("MTEP") process are evaluated for redundancy, reliability, and no-harm. Though the MISO regional planning process does ensure that federal, state, and local laws and mandates are evaluated during the MISO Value Based Planning process, there is not a distinct planning process to identify public policy needs or solutions to address them.

SPP

In its 2020 Integrated Transmission Plan ("ITP"), SPP focused on the development of an optimized transmission system in its transmission planning processes. Its 2020 ITP assessment encompassed policy, operational, economic, and reliability aspects to consolidate and optimize collective results into a holistic transmission portfolio to address the needs identified during the study.[40] The assessment included more robust Futures scenarios than in the prior year to better forecast renewable development. SPP appears to be optimizing reliability and economic planning processes. Except for one incumbent transmission owner (Southwestern Public Service Company), SPP transmission owners do not have a local transmission planning process that is separate from the regional planning process. The RTO evaluates the local and regional planning processes concurrently. SPP reviews transmission projects for redundancy and consolidation and evaluates the portfolio of projects against the Futures used over a 40-year period.

Generation resources, and the associated upgrades required for their interconnection, are included in the base reliability model if the resources have executed interconnection agreements or are designated as a resource with affiliated transmission service (or have special waivers). However, the generator interconnection process is siloed and on a different timeline.

Though, for the most part, regional and local reliability planning processes are integrated in SPP, the baseline reliability planning process and the market efficiency planning processes appear to be separate and use a different set of models and assumptions.

PJM

In PJM, local reliability projects are identified by transmission owners in the local planning process and the RTO uses the regional reliability models to identify any regional reliability issues. Supplemental projects are not regionally allocated or developed through the Regional Transmission

40 SPP, Recommendation to the Market and Operations Policy Committee, 2020 Integrated Transmission Plan Assessment (October 2020) at 3.

Expansion Plan ("RTEP") process; however, they are included in the RTEP as a baseline reliability project. A Supplemental Project is a transmission expansion or enhancements not needed to comply with PJM reliability, operational performance, FERC Form No. 715, economic criteria or State Agreement Approach projects. Although Supplemental Projects are included in the RTEP, they do not require PJM Board approval.

After an initial set of RTEP projects are selected, PJM performs a combined review of the accelerated reliability projects and new Market Efficiency Projects ("MEP") with a B/C ratio of 1.25 or higher to determine the most efficient solution overall, which may result in changes to the initial set of RTEP projects. This final combined review may result in modifications to reliability-based enhancements already included in RTEP to relieve one or more economic constraints. Though inputs to the RTEP process are initiated in separate siloed processes (i.e., local planning processes, transmission owner supplemental projects, the generator interconnection process, and capacity markets), an effort is made to integrate and optimize the results of these separate inputs in the final stages of the RTEP process.

Proposed Solutions

The need for more efficient transmission planning that will identify backbone upgrades in the planning process and the need to co-optimize the generation interconnection and transmission planning processes for the region were clearly identified as pressing needs during the interview process. At the regional and local level, most participants stressed that all planning needs should be centrally coordinated.

Interview respondents advocated for fully integrated planning processes (versus siloed processes) that integrate and co-optimize: (1) the generator interconnection process; (2) transmission requests for regional load additions; (3) local and regional reliability planning; (4) long-range regional transmission planning; and (5) state policy and public policy goals. They also suggested that planning models should incorporate utility Integrated Resource Plans ("IRPs") into the assumptions used in the regional transmission planning process (where this is not already happening). If the various components of transmission planning remain resident in their separate processes, it was suggested that the RTOs consider putting reliability planning, economic planning, and interconnection planning on the same schedule. Needs identified in the different processes should be consolidated and optimized in the planning process to produce a better design that meets the needs of all of the processes and identifies a more appropriate mechanism to share costs between interconnecting generators and wholesale loads. Most agreed that a longer-term view of future planning is necessary, similar to a long-term integrated resource plan for the RTO.

The lack of resources and accountability at the RTO for the timing of studies was frequently cited as a contributor to the extreme delays in Interconnection and Affected System Studies and the larger problem of connecting new renewable resources. In SPP and PJM, Affected System Studies and Interconnection Studies have been significantly delayed (in some instances for as much as four years). Putting planning and generator interconnection processes on the same timeline may help to streamline processes, facilitate integration between processes, and save resources. Streamlining and dispensing with models that are not adding value, and/or increasing time intervals between studies (or only producing new studies when there has been a material change) were also suggested as potential improvements. Lack of resources was a particular concern for SPP and PJM, where Affected Systems Studies and Interconnection Studies have been significantly delayed and the RTOs are known to be under-staffed.

A frequent comment was that local reliability planning should be brought into the regional planning process. This would allow regional planners to identify opportunities to scale certain local reliability projects. It was suggested that it is possible to realize the long-term view of what the grid of the future should look like, while optimizing existing transmission corridors and minimizing the need for new utility rights-of-way. Utilities have a vast number of existing rights-of-way and when there are asset replacements addressing age and condition issues there should be an assessment to determine if utilities should upgrade and raise the voltage ("right-sizing") or perhaps add a double circuit. There were many proponents for "right-sizing," accepting that the utility will dominate transmission development in its own service territory, and could right-size reliability projects to reflect other system needs, such as interconnecting new renewable generation. This proposal was generally well-received by other commenters as a step in the right direction.

INTERVIEW QUOTE:

"Best solution, plan for all needs from top down. Local reliability is an input [to the regional planning process] and we are missing opportunities to optimize them. When individual transmission owners are planning only for their own needs, we miss opportunities to scale a project."
– *Renewable Energy Organization*

From a consumer perspective, it was suggested by some that there should be a standard planning protocol, set by a national organization, for all transmission projects even at the state level and planning processes should be centrally coordinated. Some advocated that a FERC-approved local planning process should be required. Recently in PJM, FERC determined where there is a legitimate overlap between regional planning processes and local reliability planning, local projects should become part of the regional planning process. Some respondents were in favor of doing away with "local" reliability standards entirely, and only maintaining "regional" or "national" standards. Others argued that local planning criteria should, at a minimum, be evaluated to ensure their application is not discriminatory. Further, some stated that any national protocol should consider ways to achieve independence at the ISO level. This could be accomplished by a national or regional planning authority, independent and with planning authority over the ISOs.

Several commenters suggested that transmission planners should create a process or criteria to add advanced technologies into the mix of potential solutions. Currently, planners are not looking at advanced technology solutions for what may be the most efficient solution for a given constraint. Planners should consider solutions that go beyond transmission, such as better load management, energy storage technologies, dynamic line ratings,[41] and distributed generation. All of which may also help to alleviate some upgrade costs with interconnection. Advanced technologies could provide both reliability and economic benefits, are modular, typically less expensive, and can afford a great deal of system flexibility that may be useful in a variety of system conditions. ACEG recommends in its recent paper that FERC require a targeted assessment as part of the planning process to determine how grid enhancing technologies could improve existing system operations or could be utilized in the long-term solution mix in conjunction with new infrastructure improvements.[42]

41 FERC issued a Notice of Public Rulemaking ("NOPR") in November 2020, which proposed that all transmission providers implement ambient-adjusted ratings ("AAR") as opposed to seasonal ratings beginning within the next year. See FERC NOPR, Managing Transmission Line Ratings, Docket No. RM20-16-000 (November 19, 2020). FERC found that (with the exception of PJM, and two transmission owners in MISO) most transmission owners implemented seasonal or static transmission line ratings, based on conservative, worst-case assumptions that do not reflect the true cost of delivering wholesale energy. Such line ratings directly affect the dispatch and unit commitment computations by constraining power flows on individual transmission facilities, resulting in congestion costs in LMPs. FERC noted, by increasing transfer capability, congestion costs will, on average decline; and cited a study indicating that if AAR had been implemented in MISO in 2017 and 2018, congestion costs would have been reduced by approximately $94 million and $78 million, respectively.

42 Gramlich and Caspary, Planning for the future, supra note 6, at 42.

The Public Utility Commission of Texas's ("PUCT's") Competitive Renewable Energy Zones ("CREZ") initiative as well as the MISO Multi-Value Projects ("MVPs") were mentioned as good models for centrally coordinated regional planning that integrated and co-optimized regional processes and were successful in developing necessary backbone transmission that facilitated new generator interconnections. In both cases, costs were socialized across the region in rates, as it was recognized that the new generation facilitated by the lines would provide broad benefits.

It was suggested that the CREZ model, which created resource zones and created transfers across regions could and should be implemented to facilitate renewable development in other regions. In the CREZ model, the Texas legislature directed the PUCT to identify wind energy production potential and any possible transmission constraints to impede its delivery. Using this study, the PUCT developed a transmission plan to optimize and enable low-cost wind resources in West Texas. The transmission lines connecting that resource to load were subject to a competitive solicitation and were constructed in five years, beginning in 2009, unlocking 18,000 MW of additional capacity.[43]

In New York, the New York State Energy Research and Development Authority ("NYSERDA") is tasked with bringing 9,000 MW of offshore wind to New York by 2035 (with an overall offshore wind goal of 26,000 MW) and has also been lauded as a "best practice" model of a centrally coordinated planning initiative. It began with the Climate Leadership and Community Protection Act, which laid out New York's 100 percent clean energy mandate by 2040. Between 2016 and 2018 NYSERDA developed the New York State Offshore Wind Master Plan, which provided a comprehensive roadmap to reaching its aggressive wind targets. The Plan was informed by extensive stakeholder involvement that focused on the development of offshore wind with sensitivity to environmental, maritime, economic, and social factors, while focusing on lowering costs and removing market barriers.[44] To date, NYSERDA has issued two solicitations to procure in excess of 4,000 MW of offshore wind.[45] It is currently studying the most cost-effective approach to transmitting the wind generation to identified points of interconnection on land and will hold a future competitive solicitation for offshore transmission developers to construct the required transmission.[46] This is another excellent example of successful centrally coordinated planning, albeit only one state was involved in that process and the MISO, SPP, and PJM service territories cover multiple states.

INTERVIEW QUOTE:

"Overlying message – everyone is moving to renewables – we need a system that works to meet that appetite."

– *Renewable Energy Developer*

43 A Renewable America, A project of the Wind Solar Alliance, Corporate Renewable Procurement and Transmission Planning: Communicating Demand To RTOs Necessary To Secure Future Procurement Options (October 2018) at 7-8. https://windsolaralliance.org/wp-content/uploads/2018/10/Corporates-Renewable-Procurement-and-Transmission-Report-FINAL.pdf.

44 Maria Blais Costello, An inside look at NYSERDA's award-winning offshore wind program, Windpower Engineering & Development, (August 27, 2020), available at https://www.windpowerengineering.com/an-inside-look-at-nyserdas-award-winning-offshore-wind-program/.

45 NYSERDA, Offshore Wind Solicitations, avaliable at https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/Focus-Areas/Offshore-Wind-Solicitations.

46 Johannes Pfeifenberger et al., Offshore Wind Transmission, An Analysis of Options for New York, The Brattle Group, http://ny.anbaric.com/wp-content/uploads/2020/08/2020-08-05-New-York-Offshore-Transmission-Final-2.pdf at 15.

Conclusions

Centrally coordinated planning at the national or interregional level, and at the RTO level, is needed to identify where untapped renewable energy resources exist and develop optimal and cost-efficient paths for infrastructure development to deploy trapped renewable energy resources and bring resources to market. Centrally coordinated planning should provide for advanced technology solutions (where appropriate) and realistic estimates of future renewable energy production.

Regional economic transmission planning processes, regional reliability transmission planning processes, local reliability planning processes, and generator interconnection processes should be integrated or at least consolidated and subject to a national planning standard.

Description of the Issue

Joint planning between RTOs has been largely ineffective and has not resulted in the necessary level of interregional transmission projects. Problems are occurring on all seams, e.g., the MISO-SPP seam in the Dakotas, Nebraska, Iowa, and Missouri with respect to wind specifically. The interface between PJM and MISO is also problematic. The RTOs use their own respective internal models for exporting power out of SPP or MISO, which leads to disagreement about the need for interregional transmission upgrades. Upgrades must pass both regional and interregional thresholds, which can be challenging and leads to the rejection of the majority of proposed projects. During market participant interviews, there was one participant that mentioned that in 2014, a group of generators decided to fund their own $55 million upgrade in the NIPSCO system, at the PJM/MISO seam, because the interregional planning process benefit threshold for new projects was too stringent.

INTERVIEW QUOTE:

"The interregional process between SPP and MISO is where good projects go to die. Modeling is a huge issue. We need to understand that they are using two different models and that is how they determine what they are willing to pay. If you look at a common construct, MISO and SPP will work better together."
– *Transmission Developer*

There is a need to work towards harmonizing and aligning rules, assumptions, benefit metrics, and cost allocation across RTOs. Each RTO has its own models, operational practices, and set of differing priorities. Currently, there is no common set of assumptions and there is generally a lack of coordination between the RTOs.[47] This results in different B/C ratio estimates for the same project which can cause a project to fail in one system and be accepted in the other. For example, in the SPP 2020 ITP Recommendation, this issue was specifically addressed.

> *The 2020 ITP introduced the MISO Regional Directional Transfer (RDT) target area to the analysis. The MISO RDT was classified as a target area to aid in regionally coordinated efforts to identify and evaluate potential transmission upgrades needed to mitigate impacts to the SPP transmission system due to transfers between the MISO Midwest and MISO South regions. SPP has historically seen congestion in the SPP footprint related to north-to-south flows within MISO, and a number of projects were considered.* ***Due to differing methodologies between MISO and SPP when calculating benefits and project costs, the two RTOs decided not to pursue any projects in this area as part of the 2020 ITP.***[48]

Only projects that are deemed sufficiently beneficial in both systems, typically with a cost/benefit ratio of 1.25 or above, will move forward. A more unified model is needed to properly assess production costs and benefits. This will require RTOs and stakeholders to come together with the same vision.

47 One notable exception is the MISO/SPP Joint Interconnection Study, announced in September 2020, that will target interconnection challenges on the seams. The Study will identify cost effective and efficient transmission upgrades that will include a simultaneous allocation of benefits and/or costs to both load and interconnection customers. The joint study is to kick off at the end of 2020 and will operate in parallel with each of the ISOs planning and interconnection processes.

48 SPP, Recommendation to the Market and Operations Policy Committee, 2020 Integrated Transmission Plan Assessment (October 2020) at 3 [emphasis added].

Many respondents voiced concern over the FERC's 2019 Order that allowed MISO and SPP to move away from their joint planning model.[49] It was expressed in our interviews that the lack of a joint planning model eliminates the shared learning and coordination that the two RTOs were required to undertake to develop the joint model. The concern is that without alignment in assumptions for cost allocation based on each region's assessment of benefits, the ability to find mutually beneficial projects is compromised. It was expressed that the more adjacent markets can perform like one market the greater the benefit.

Relevant RTO Processes

As discussed previously, joint studies have been conducted along both the MISO/SPP seam and the MISO/PJM seam. In the last five years, there have been very few MEPs identified as beneficial out of the joint planning processes along the MISO/PJM seam. There have been a number of targeted MEPs that have received joint approval, and in 2018 the Bosserman-Trail Creek project was recommended by PJM and MISO to address persistent historical congestion projected to continue on the NIPSCO/AEP seam.[50] The MISO/SPP process has not resulted in the recommendation of any projects to date.

As indicated above, in July 2019, the FERC approved changes to the MISO/SPP interregional planning process to eliminate use of a joint model and enable the two RTOs to determine their own assessment of benefits.[51] To date, MISO and SPP have independently evaluated the benefits of the transmission solutions proposed using each RTO's share of calculated APC benefits, as calculated using the methodologies used in each RTO to allocate the costs of economic interregional projects to each planning region. Solutions that primarily address reliability issues are allocated to MISO and SPP based on the sum of each RTO's avoided cost to address the reliability issue and the APC benefits.[52]

The benefit metrics MISO and SPP independently calculate to evaluate potential interregional projects that primarily address economic needs are based on APC,[53] with any reliability and public policy benefits, to the extent they exist, being added to the APC benefits.[54] Any economic benefits of reliability-focused projects are added to the avoided reliability cost metric.[55] If an interregional project primarily focuses on public policy needs and replaces a SPP or MISO (or both) project to address a public policy issue, the public policy benefit is the avoided cost of the displaced public policy projects.[56] Any economic benefits of public policy-focused projects are added to the public policy benefit metric.[57]

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49 Midcontinent Independent System Operator, Inc. Southwest Power Pool, Inc., 168 FERC ¶ 61,018 (July 16, 2019) at P 5. The revisions also included process improvements. [hereinafter MISO and SPP tariff filing].
50 PJM, 2019 RTEP, at 56.
51 MISO and SPP tariff filing, supra note 49.
52 SPP-MISO JOA § 9.6.3.1.1.
53 SPP-MISO JOA § 9.6.3.1.1.a.
54 SPP-MISO JOA § 9.6.3.1.1.a.iii-iv.
55 SPP-MISO JOA § 9.6.3.1.1.b.ii.
56 SPP-MISO JOA § 9.6.3.1.1.c.
57 SPP-MISO JOA § 9.6.3.1.1.c.ii.

As mentioned previously, in September 2020, MISO and SPP announced a joint study that will "focus on solutions that the RTOs believe will offer benefits to both their interconnection customers and end use consumers of RTO member companies."[58] MISO and SPP appear to recognize that upgrades identified in the generator interconnection process could also address the transmission needs of RTO loads and will benefit loads as well.

Proposed Solutions

Respondents strongly voiced a need for better alignment of interregional planning model assumptions or the movement to a unified planning model. Some advocated for a national policy for interregional development. It was proposed that a national baseline planning model could be established as a starting point, with rules, assumptions, and benefits that FERC or another interregional planning entity would require. This baseline planning model would serve as a reasonable floor based on standardized best practices. Beyond the baseline model, each RTO would have the flexibility to experiment with additional rules, assumptions, and benefits, providing such estimates do not cause B/C estimates to fall below the floor. Others advocated for a unified model with a singular set of methodologies, assumptions, and benefits.

INTERVIEW QUOTE:

"Until there is one single interregional process with a single hurdle and shared assumptions, I don't see process as it stands today really producing much."
– *Renewable Energy Developer*

Conclusions

Interregional transmission planning should rely on either a unified national interregional planning model or regional models that have sufficient alignment of rules, assumptions, benefit metrics, and cost allocation methodologies to properly assess benefits and costs of jointly planned transmission projects.

58 MISO. (September 14, 2020). MISO and SPP to conduct Joint Study Targeting Interconnection Challenges [Press release]. https://www.misoenergy.org/about/media-center/miso-and-spp-to-conduct-joint-study-targeting-interconnection-challenges/.

Description of the Issue

Transmission planning processes consistently under forecast renewable generation, and as a result, the transmission system is not being built out timely enough to facilitate the interconnection and integration of the lowest-cost renewable generation necessary to support announced state and utility clean energy plans. One factor contributing to this issue is that in baseline transmission planning models, planners focus only on firm commitments in the generator interconnection queues to project renewable energy Futures, and do not look beyond commitments in the interconnection queues, or to third party forecasts, trends or targets. As a result, network upgrades that should have been identified in planning processes are instead not identified until the generator is assigned the network upgrade cost in the generator interconnection process. Even with projections of renewables that have obtained firm signed interconnection agreements, planners may be too conservative in modeling the dispatch of renewable capacity, often at fractions of expected capacity.

The other primary contributing factor to the understatement of renewable Futures in planning models is that actual renewable development has substantially outpaced expectations. This is most likely attributable to the quicker-then-expected evolution of renewable resources to become the least cost resource - now economically dispatched in real time.[59] Renewable resources have evolved from a public policy solution to a market solution. Now that renewable resources are identified by the market as the least cost resource, there is a market need for the resource to which generators are responding beyond what was anticipated in the planning models' renewable Futures cases.

INTERVIEW QUOTES:

"Even aggressive scenarios of futures aren't even close to reality or what we will need to do to meet clean policy objectives coming from states and consumers."
– *Investor-Owned Utility*

"It's been a trend that planners have not adequately forecast renewables and by the time the transmission study is done, assumptions are obsolete, particularly in SPP; the renewable generation is already online."
– *Renewable Energy Developer*

"Incumbent transmission owners drive under-forecasting. Incumbents will push back - making assumptions only on what is in the queue. We need to put weight on trends."
– *Transmission Developer*

There is also a political element to developing renewable energy Futures cases. Several respondents noted that transmission owners are very resistant to the inclusion of aggressive "high renewables" Futures cases in planning models over concerns about the necessary transmission expansion that would result, which often would result in socializing transmission costs to their customers and would consume valuable head room in utility rates. Further, transmission owners exert significant influence over the planning processes and the ISOs and have, in the past, stymied aggressive renewable energy Futures projections put forth in planning models.

59 See NRDC Planning Tool which calculates the levelized cost of energy for generation resources: nuclear, coal, natural gas combined cycle, solar, and wind. Under base case assumptions for the national average, solar surpassed natural gas as the cheapest resource in 2018 and wind in 2020. Available at https://www.nrdc.org/cost-building-power-plants-your-state.

Respondents emphasized a need to be proactive. Transmission takes a long time to build, and the construction of transmission projects should begin several years in advance of renewables. Acknowledging that it is not possible to predict the future with absolute accuracy, the inability to move forward with transmission expansion (even in cases that are 'win-win'), will result in a transmission system that is not prepared in time to meet our future energy needs.

Relevant RTO Processes (from Appendix B)

MISO

MISO develops Futures, or assumptions about the outcomes of key ISO market drivers, before each MTEP cycle and the various Futures are used in the MTEP process. The MTEP20 cycle included four Futures: Limited Fleet Change; Continued Fleet Change; Accelerated Fleet Change; and Distributed and Emerging Technologies. Futures also project alternate forecasts of electrification of the transportation fleet, energy efficiency, new unit construction costs, emissions constraints, retirements, renewable energy development, and regional demand and energy projections.

All existing generators and future generators with a filed Interconnection Agreement and in-service date in the planning horizon are included in the baseline transmission planning model. MISO's generation retirements are also included in the baseline model. According to the MISO transmission planning manual, "sufficient renewable generation will be modeled to meet renewable portfolio standard mandates effective during the applicable planning horizon." However, the MISO models have tended to under-project renewable resource additions because much more than the Renewable Portfolio Standard ("RPS") requirements are driving renewable development. For example, MISO noted in the 2020 MTEP report that "Looking ahead as it began the MTEP20 cycle, MISO saw increasing momentum in fleet development and many stakeholders noted how new generation could outpace bookends within the planning horizon." As a result, MISO worked with stakeholders to update these models and additional changes are expected in the MTEP21 Futures. It was noted by several interview respondents that the MTEP21 Futures are a much better representation of potential future resource mix changes, and these Futures are expected to be used for several planning cycles.

SPP

According to the SPP ITP manual, generation resources, and the associated upgrades required for their interconnection, are included in the base reliability model if the resource is in service or if the resource has an effective Generator Interconnection Agreement ("GIA") and long-term firm transmission service agreement. Exceptions exist for transmission solutions that solve a model issue or for which a waiver has been specifically requested and granted.

Planned resources and associated transmission service requests that are not in service but have a high probability of going into service can request to be included in the base reliability model. Resources that have been mothballed or are planned for retirement must be submitted into SPP's modeling system for their retirement to be accounted for in the base reliability model. Note that, like MISO, only resources with executed GIAs are considered in the base reliability models.

In economic models, wind and solar generation estimates are driven by state policy drivers such as renewable portfolio standards in the SPP footprint. However, due to the high renewable development, assumed Futures in the economic models over the 10-year planning horizon do not include the additional expected wind and solar resources.

Similar to the issues experienced in the MTEP transmission planning process, SPP noted in its 2020 ITP assessment report that prior ITP assessments did not assume sufficient renewable generation to assess transmission needs, "Previous ITP assessments have been conservative in forecasting the amount of renewable generation expected to interconnect to the grid. When the studies were completed, installed amounts had nearly surpassed 10-year forecasts."[60]

SPP acknowledged the impact that low estimates of renewable Futures can have on transmission investment in its 2020 ITP, where it stated, "Overly conservative forecasts can lead to delayed transmission investment, contributing to persistent congestion. For example, the 2020 consolidated portfolio is expected to address eight congested flow gates identified over the last four quarterly SPP corporate metric updates."[61] According to SPP, "[f]or the 2020 ITP assessment, SPP expanded on the 2019 assessment's analysis to better forecast renewables development, which will allow the region to proactively build the infrastructure needed to alleviate congestion and provide access to less expensive energy."[62] However, while higher than that assumed in the 2019 ITP, the 2020 Futures continued to fall short of development.

PJM

According to the PJM RTEP manual, each Futures case is developed from the most recent set of Eastern Reliability Assessment Group system models, which are revised as needed to incorporate all the current system parameters and assumptions. These assumptions include current loads, installed generating capacity, transmission and generation maintenance, system topology, and the most recently finalized local plans and firm transactions.

If no capacity is needed to meet the planning reserve margin, queue generators in earlier stages of the interconnection queue process may also be included. According to the RTEP manual, PJM employs the following guidelines regarding when to include the planned projects or upgrades in the annual RTEP base case:

1. Baseline upgrades are included in the next RTEP base case once the baseline upgrade is approved by the PJM Board.
2. Customer-Funded Upgrades (e.g., pursuant generator interconnection requests) may be included in the next RTEP base case once the customer has executed one or more PJM agreements or if the completion of the RTEP requires inclusion of New Service Queue Requests with an executed Facilities Study Agreement to meet the new load requirements resulting from normal forecasted load growth.
3. A Customer-Funded Upgrade may be removed from the RTEP base case if an agreement is cancelled or terminated, provided such upgrade is not required by a subsequent New Services Queue Request with an executed service agreement.
4. Supplemental Projects will be included in the next RTEP base if they are included in the Local Plan.

60 SPP, 2020 Integrated Transmission Planning Assessment Report (October 2020), at 2.
61 Ibid.
62 Ibid.

5. Subject to certain conditions, projects may be excluded if a regulatory siting authority denies the project through a final regulatory order that exhausts all regulatory processes that would enable the project to move forward.

Generation retirements will not affect the study results for any generation or merchant transmission project that has received an Impact Study Report, in such case, the generator retirements are applied in the next baseline update.

The results of capacity market auctions are used to help determine the amount and location of generation or demand side resources included in the reliability models. Generation or demand side resources that cleared any locational capacity auction are included in the reliability models, but generation or demand side resources that either do not bid or do not clear in any capacity auction will not be included in the reliability models.

Proposed Solutions

Planning models should include reasonable estimates of future renewable generation. There is a need to look at energy policy and what is in the interconnection queues and not only what has firm interconnection commitments. Reasonable futures should also consider projections from external sources, such as third-party studies and utility IRPs.

The Renewable Integration Impact Assessment (RIIA) in MISO was identified as a promising initiative for removing barriers to renewables integration. RIIA was established in late 2017, to study renewable integration issues and examine potential solutions to mitigate them in order to manage renewable penetration levels and better understand the impacts of renewable energy growth in MISO over the long term.[63] To date, RIIA has found that when the percentage of annual load served by renewable resources is less than 30 percent (currently 13 percent in MISO) that incremental changes to transmission expansion and planning practices are manageable. But, above the 30 percent level, significant system-wide complications may arise, absent adequate planning and system preparation. The complications arise due principally to changes in resource availability and lack of transmission capacity. RIIA presents technically feasible solutions to obtain 50 percent renewable penetration that it claims can be achieved through coordinated actions.[64] While RIIA is not intended as a transmission planning study, RIIA does clearly demonstrate that significant investment in transmission will be needed to support the region's changing resource mix.[65]

Several respondents expressed that the ISOs and RTOs will need to make predictions of future load growth, renewable builds, and assumptions about dispatch, beyond what is currently secured in the interconnection queues. It was expressed that the ISOs and RTOs should also direct what units will be turned off or back online and proactively require retirements.

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63 Renewable Integration Impact Assessment Concept Paper (September 27, 2017) at 2 [paraphrased]. https://cdn.misoenergy.org/20170927%20PAC%20Item%2003i%20Renewable%20Integration%20Impact%20Assessment%20Assumption%20Concept%20Paper429755.pdf.

64 MISO's Renewable Integration Impact Assessment (RIIA) Executive Summary (February 2021) at pp. 1 and 4. https://cdn.misoenergy.org/RIIA%20Executive%20Summary520053.pdf.

65 See e.g. Armando L. Figueroa-Acevedo et al., Visualizing the Impacts of Renewable Energy Growth in the U.S. Midcontinent, (January 17, 2020) available at https://ieeexplore.ieee.org/document/8962249?denied=.

Some pointed to the CREZ model for solving the historical 'chicken and the egg' problem of new transmission lines being built only when a generator had secured a GIA, and generators only building new generation where there exists adequate transmission capacity. A CREZ-like process could similarly be initiated by the RTOs, planning authorities or FERC. This process could either be integrated into the Futures projections in planning models or could circumvent the process entirely. A CREZ-like model would essentially develop a plan that concurrently enables renewable energy development and electric transmission, while optimizing resources within and across regions.

Conclusions

Transmission planners need to look beyond signed commitments in the generator interconnection queue to energy policy, utility IRPs, and independent, third-party expert studies to develop reasonable expectations of renewable Futures. This should include reasonable expectations for storage, renewable and gas generation additions, as well as fossil fuel plant retirements. It was suggested that a minimum of three Futures scenarios should be incorporated in planning models.

Description of the Issue

The metrics RTOs use to identify beneficial transmission projects do not adequately capture the full range of benefits of any given modern-day transmission project. Without a means to assess the full range of project benefits, incorrect and suboptimal planning decisions will inevitably be made. Most RTOs rely primarily on APC savings to evaluate project benefits, though each RTO may look to a different limited set of additional benefits in assessing overall project benefits. APC metrics are calculated by determining the cost to run and operate a unit in normal base case conditions, less revenues from hourly net sales. This metric only provides estimates of short-term cost savings under baseline conditions and does not capture benefits associated with the diversity of renewable generation, reduction of transmission losses, and public policy benefits of renewable generation. It is generally assumed that many of these additional benefits may be difficult to quantify and as a result are given little to no consideration in determining the ultimate value of a transmission project.

In addition, the assessment of project benefits can vary by state, depending on state policy goals, and by RTO. There are currently diverse and opposing views of project benefits among states, and it could prove difficult to achieve consensus on a set of new benefit metrics.

Relevant RTO Processes (from Appendix B)

MISO

A MEP in MISO must meet specific benefit requirements to be recommended in the MTEP and eligible for regional cost allocation. Projects qualify as MEPs based on cost and voltage thresholds and are developed to produce a benefit-to-cost ("B/C") ratio of 1.25 or greater.

The benefit metrics used to assess MEPs are listed below:

1. APC savings are calculated as the difference in total production cost of the resources in each MISO cost allocation zone, adjusted for import costs and export revenues, with and without the proposed MEP.
2. Avoided Reliability Project Savings metric quantifies the savings from reliability projects no longer needed as a result of the MEP.
3. MISO-SPP Settlement Agreement Cost metric to capture the impact of reduced or increased payments resulting from the MISO-SPP capacity sharing Settlement Agreement.

The three benefit metrics are added together and used to evaluate whether the MISO-Tariff defined 1.25 B/C ratio is satisfied.

MVPs refer to network upgrade projects that satisfy multiple transmission criteria. The projects are regional in nature and enable compliance with public policy requirements, and/or provide economic value. The costs of these projects are entirely socialized across load. MVP's consider a wider array of benefits than MEPs detailed above and are required to have a B/C ratio of 1.0 or higher. The benefit metric used to assess MVPs may consider the following additional benefits:

1. Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator operating reserve costs.
2. Capacity cost savings due to a reduction of system losses during the system peak demand.

3. Capacity cost savings due to reductions in the overall planning reserve margins resulting from transmission expansion.
4. Long-term cost savings realized by transmission customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by transmission customers by deferring or eliminating the need to perform one or more projects in the future due to pursuit of a specific MVP.
5. Any other financially quantifiable benefit to transmission customers resulting from an enhancement to the transmission system and directly related to providing transmission service. Financially quantifiable benefits not directly related to providing transmission service, such as economic development benefits and other types of benefits not directly related to providing transmission service, cannot be considered in qualifying a project for MVP status.[66]

MISO calculates benefits over the first 20 years of project life after the projected in-service date, with a maximum planning horizon of 25 years from the approval year.

SPP

SPP uses APC to identify projects in ITP economic studies. The APC metric quantifies the monetary cost associated with fuel costs, generation dispatch, grid congestion, energy purchases, energy sales, and other factors that directly relate to energy production by generating resources in the SPP footprint. The APC metric also captures the cost savings associated with reduced emissions by considering allowance prices for SO_2, NO_X, and CO_2 and savings due to lower ancillary service needs and production costs. However, SPP notes in its Benefit Metrics Manual, that APC metrics have limitations and that there are production cost savings that are not captured in the standard APC metric. This is due to the derivation of APC metrics based on production cost simulations for a base case and a change case that include a number of simplified assumptions. Among them:

- The simulations assume that transmission facilities are available 100% of the time, thereby ignoring any maintenance and forced outages of transmission facilities.
- The simulations assume that the MWh quantity of losses is fixed and does not change with transmission additions, thereby ignoring that transmission expansion may reduce the MWh quantity of losses that need to be supplied.
- The simulations tend to assume that hourly wind generation is perfectly known when generation units are committed for the next day, thereby ignoring the fact that the hourly level of wind generation is uncertain.
- The calculation of APC is based on a number of simplifying assumptions regarding the extent to which congestion costs can be hedged through auction revenue rights (“ARRs”) in a day 2 market environment. For example, it assumes congestion between owned generation and load can be fully hedged while none of market-based purchases would be hedged. [67]

We expect that these same limitations exist across all three RTOs.

Interview respondents reported that SPP uses a more robust set of benefit metrics to evaluate project benefits after the design phase of projects chosen for the final portfolio. However, these

66 MISO Transmission Planning Manual, Section 7.5.3.
67 SPP Benefit Metrics Manual (May 2017) at pp. 5-8.

metrics are not used to select the projects and are developed after the final portfolio is selected. In SPP, economic solutions are evaluated based on criteria developed by SPP and stakeholders which are described in the study scope. Solutions that mitigate economic needs are ranked by their cost effectiveness, net APC benefit and multivariable qualitative benefits for each need or set of needs. Solutions are categorized into the following three groupings:

- Cost effective: Solutions with the lowest cost with respect to the congestion relief they provide on individual flow gates will be selected.
- Highest net APC benefit: Solutions with the highest difference between one-year APC benefit and one-year project cost will be selected.
- Multi-variable: Top-ranking projects in the other two groupings, as well as qualitative benefits that the other groupings may not capture, will be considered when selecting projects.[68]

All solutions are evaluated on a one-year B/C ratio and a 40-year net present value B/C ratio. MEPs must meet at least a 0.5 one-year B/C ratio or a 1.0 40-year net present value (NPV) B/C ratio to be considered in the ITP portfolio.[69] The additional benefits measured after the portfolio is selected are listed below:

1. Capacity cost savings due to reduced on-peak transmission losses
2. Avoided or delayed reliability projects
3. Mitigation of transmission outage costs
4. Assumed benefit of mandated reliability projects
5. Marginal energy losses
6. Increased wheeling through-and-out revenues
7. Benefit from meeting public policy goals[70]

PJM

PJM calculates the annual benefit of a MEP, known as the "Total Annual Enhancement Benefit" as the sum of two benefit metrics: (1) the Energy Market Benefit; and (2) the Reliability Pricing Market benefit.[71] The Energy Market Benefit metric uses production cost model runs and compares the simulations over the RTEP planning horizon with and without the project to identify these benefits. The benefit metric equally considers changes in energy production costs and changes in load energy payments for regional projects.[72] However, lower voltage projects consider only changes in load energy payments.[73] The Reliability Pricing Model Benefit is calculated by simulating PJM capacity market outcomes with and without the MEP being studied. Several PJM benefit metrics estimate the changes in energy and capacity payments to PJM loads. This differs somewhat from the APC metrics used in MISO and SPP, which evaluate production costs. Both the Energy Market and Reliability Pricing Model benefit metrics are calculated over the RTEP planning horizon according to the

68 SPP ITP Manual, Section 6.1.1.
69 Ibid., Section 5.3.1.
70 Ibid.
71 PJM RTEP Manual, Appendix E, Section E.1.
72 Ibid.
73 Ibid.

upgrade's assumed in-service date. MEPs must have a B/C ratio of at least 1.25 to be included in the RTEP.

Proposed Solutions

Most agreed that a wider range of benefits that go beyond traditional production cost savings should be factored into transmission project selection criteria and decisions. However, respondents were mixed on how best to accomplish this. Some advocated for the incorporation of a wider range of benefits into the B/C metric calculation for purposes of meeting a specified B/C threshold criteria, and selecting transmission projects on the basis of a ranking of B/C metrics. Other participants expressed concerns over a more robust benefits framework, i.e., that expanding benefits may over-complicate an already over-burdened process. The concerns focused on the risk that if all of the identified benefits were included in initial benefit to cost hurdles, disagreement over benefits among stakeholders may derail the process, and transmission might not get built at all.

INTERVIEW QUOTE:

"Benefit metrics need to be quantifiable. Not a huge fan of subjective metrics, creates a bigger fight on who pays."

– *Renewable and Infrastructure Developer*

Further, it was recognized that quantifiable benefit metrics will be more readily recognized and agreed upon by market participants than more subjective benefits, which could result in disagreements about benefits and ultimate cost determinations. It was generally acknowledged that non-quantifiable benefits should also be considered and factored into project selection criteria. These less-quantifiable benefits would include such project attributes as the benefits associated with fulfilling a state policy objective, environmental considerations, resiliency, increased fuel diversity, geographic diversity, economic development, etc.

The following table was extracted from a 2013 Brattle Group study for WIRES, where the authors provided a robust spectrum of transmission benefits providing a comprehensive template of benefits that could be considered when evaluating new transmission projects. The table contemplates an expansion of the traditional production cost savings calculation in addition to other cost savings and other less-quantifiable benefits. The authors proposed an inclusive benefits calculation that includes all benefits, even those that are difficult to quantify. To do otherwise, they suggest, would limit the evaluation of benefits to only a portion of the actual benefits of a project and could lead to the rejection of beneficial projects. The authors pointed out that by "[o]mitting consideration of such difficult-to-estimate benefits inherently assigns a zero value and thereby results in an understatement of total project benefits."[74]

[74] Chang, Pfeifenberger and Haggerty, A WIRES Report on The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments (July 2013) at iv.

Table 1: Potential Benefits of Transmission Investments[75]

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated
1a—1i. Additional Production Cost Savings	a. Reduced transmission energy losses
	b. Reduced congestion due to transmission outages
	c. Mitigation of extreme events and system contingencies
	d. Mitigation of weather and load uncertainty
	e. Reduced cost due to imperfect foresight of real-time system conditions
	f. Reduced cost of cycling power plants
	g. Reduced amounts and costs of operating reserves and other ancillary services
	h. Mitigation of reliability-must-run (RMR) conditions
	i. More realistic representation of system utilization in "Day-1" markets
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability <u>or</u>
	c. Reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	c. Access to lower-cost generation resources
4. Market Benefits	a. Increased Competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employee and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased loads serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

75 Ibid. at v.

Many participants expressed that benefit metrics should be aligned between RTOs to facilitate interregional transmission planning, or even nationally, and should not be an RTO-by-RTO determination. In the Preface to the WIRES report referenced above, WIRES acknowledged the difficulty in policymakers, transmission planners and regulators reaching a common understanding of transmission's potential benefits, but also warned that differences in assumptions and approaches to transmission planning and cost could "devolve into a lowest common denominator" approach to selecting interregional projects.[76] Without consensus between RTOs on a more robust evaluation of transmission benefits, projects will be subject to the average production cost savings metrics, which arguably depicts only a fraction of the true value of a given transmission investment, and could lead to suboptimal planning decisions.

INTERVIEW QUOTE:

"The more we can include in the cost methodology the more the valuation will be more accurate as to what the benefits are."
– *Renewable Energy Organization*

Some respondents pointed to SPP's approach, where the RTO has a robust set of benefit metrics but does not use these metrics to select projects. They are used to support projects that have been selected. It was suggested that if a project could clear a 1.0 B/C ratio on the basis of APC, and has additional benefits, a further showing of benefits would help to garner support over competing projects.

It is possible that a tiered approach to benefits could provide a workable compromise where an expansive production cost savings calculation including all readily quantifiable costs (as indicated in the table above) would be the dominant B/C metric, with other more qualitative benefits factored in and afforded weight in planning decisions. Several respondents voiced that by more closely analyzing benefits, the information would also help to inform cost allocation decisions between generators and load.

Conclusions

As we continue to migrate from central station power plants to a more dynamic and distributed grid, where resources must be increasingly nimble and quick, it is important to have a benefit metric framework that is able to capture these value enhancements. The benefits associated with the latest evolution of project development can no longer be boiled down to standard measures of production cost savings without missing a significant portion of project value. Benefit metrics used to assess the comparable benefit of projects relative to their costs should be expanded to encompass a robust set of benefits for a modern transmission investment. Further, it is important for interregional transmission planning to have a common set of benefits across regions to the extent possible. Many respondents were in favor of a standardized expanded benefit metric that all regions would adopt for interregional planning purposes.

[76] Chang, Pfeifenberger and Haggerty, A WIRES Report on The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments, WIRES Preface and Commentary at 4.

Description of the Issue

Legacy transmission planning models that were developed for large central station baseload generation units are ill-suited to reflect the inherent variability and uncertainty of large numbers of small, variable, modular renewable and storage resources or mimic actual dispatchability. The generation shapes and generation total peaks, captured in planning models, do not reflect what is realistically going to happen hour-to-hour in the real time electricity flows, or what is realistically going to be the worst case. Solar and wind resource quality and characteristics and their coincidence with weather data are generally not taken into account in transmission planning processes and are often studied as if they are the same resource. Advanced and extremely fast resources can be modeled to look like legacy coal plants leading to inefficient planning decisions. Further, in some RTOs, planning models dispatch units based on firm transmission service agreements (e.g., SPP) as opposed to the economic dispatch that RTOs actually use to dispatch resources in real-time.

Legacy planning models are based on simplified determinative scenarios that plan for scenarios that rarely, if ever, occur. The legacy planning model is premised on dispatchable resources where there is control of the ramp up and ramp down, but do not factor in uncertainty of generator output, probability of generation outages, or variability of load. Matching the variability of renewable resources with the variability of load to cover capacity needs may require an entirely different planning model. Several respondents stated that a whole new class of reliability and transmission planning models is needed.

INTERVIEW QUOTES:

"Reliability modeling – they almost model it as if they are dispatching in the 90s. All models should be dispatched in a way that mirrors the way operations are flowing. All models should be a fuel-based dispatch rather than leaning on what transmission service may or may not be there."
– *Investor-Owned Utility*

"When we do transmission models it's not clear that models are sophisticated enough to show us results that reflect new technology. We will need a whole new class of reliability and transmission planning models."
– *Investor-Owned Utility*

Relevant RTO Processes (from Appendix B)

MISO

MISO Baseline Reliability models typically include all transmission elements rated at 100 kV and above and power-flow models of 2-year, 5-year, and 10-years out from the current year based on projected system conditions in accordance with the NERC TPL standards. Models for 2-years out and 5-years out are developed both for the system peak demand case and for at least one off-peak case.[77] MISO also performs a steady-state contingency analysis and a steady-state voltage stability analysis.[78]

MISO also performs a Load Deliverability study based on a 5-year out summer peak scenario to assess the system's ability to serve network loads; and a Baseline Generator Deliverability study to determine the ability of groups of generators in an area to operate at their maximum capability without being limited by transmission constraints. The Generation Deliverability analysis, based on

77 MISO, Transmission Planning Manual, Section 4.3.3.
78 Ibid., Section 4.5.1. and 4.2.5.2.

a 5-year out summer peak scenario, identifies projects that mitigate transmission system constraints that restrict generation output to below established network resource levels.[79]

SPP

The base reliability models form SPP's Reliability Needs Assessment and analyze contingencies per NERC Standard TPL-001. SPP's base reliability model set also includes a short-circuit model for a short-circuit assessment per the NERC TPL standards. SPP may also identify reliability-related operational needs such as voltage issues or thermal loading issues that cannot be controlled through re-dispatch and must be managed by either operational procedures or shedding load. The SPP BA Powerflow models are used to model reactive power issues and the P0, P1, and P2.1 planning events per NERC TPL standards. Reliability needs are evaluated for possible reclassification as economic needs during or after the reliability needs assessment. The reliability models dispatch generation, including wind and solar generation, based on whether the resources have long-term firm transmission service. Additionally, In the base reliability models, all entities are required to meet their non-coincident peak demand with firm resources.

As shown in Table 2 below, the Base Reliability model analyzes five load scenarios (Summer, Winter, Light Load, Non-Coincident, and Peak) under the base case projections. The SPP BA Economic model analyzes up to three different Futures in years 2, 5, and 10. The SPP BA Powerflow Reliability model analyses three different Futures in years 5 and 10.

Table 2: SPP ITP Assessment Models

ITP Model Sets

Description	Year 2	Year 5	Year 10	Total
Base Reliability	Summer Winter Light Load Non-Coincident Peak (3)	Summer Winter Light Load Non-Coincident Peak (3)	Summer Winter Light Load Non-Coincident Peak (3)	9
SPP BA (Economic)	One Future (1)	Each Future (1-3)	Each Future (1-3)	3-7
SPP BA Powerflow (Reliability)	One Future's Peak and Off-Peak (2)	Each Futures' Peak and Off-Peak (2-6)	Each Futures' Peak and Off-Peak (2-6)	6-14

As indicated above, SPP's reliability planning models dispatch generation, including wind and solar generation, based on whether they have long-term firm transmission service. Additionally, in the base reliability models, all entities are required to meet their non-coincident peak demand with firm resources. This practice ignores the likely economic dispatch of those units and can result in reliability issues being identified that are not likely to occur in practice.

PJM

The RTEP ensures the PJM system has no projected planning criteria violations as defined by the requirements of the NERC TPL Standards.

The PJM RTEP base case, or planning models include, but are not limited to, a base Powerflow model, and separate base models to perform short circuit and stability studies, load deliverability studies, and generator deliverability studies. The base case identifies violations of applicable NERC

[79] MISO, Draft MTEP20, Chapter 2, at 9.

and NERC regional planning standards, and Transmission Owner Reliability Planning Criteria that are filed through FERC Form 715 filings.

The 5-year or "near-term" RTEP baseline analysis, completed as part of RTEP planning cycle, includes a review of applicable reliability planning criteria on all bulk electric system facilities. The RTEP process develops solutions to any planning criteria violations identified in the studies. The annual review includes an analysis, with sensitivities, of the system at peak load for either year 1 or 2, and for year 5. A baseline system without any criteria violations is developed for the 5-year baseline, which is used for subsequent interconnection queue studies.

Proposed Solutions

INTERVIEW QUOTE:

"We need to throw out the planning process. It was developed last century for last century technology. We are decarbonizing the grid. We need to understand variable resources, we need to develop and plan around those generators. Planning around baseload coal and nuclear are very different than planning around variable wind and solar."
– Renewable Energy Developer

Planning models should reflect expected real-time dispatch, including realistic representations of wind and solar output that are correlated with weather expectations, and capture the interaction between resources, based on an economic market-based simulation over the planning horizon. Planning models that include parallel assumptions and benefit evaluations which mirror real-time operations would enhance the efficient flow of electricity across the region or between regions. A planning model that better reflects how resources behave operationally in real time makes good sense, but the issue of how to model legacy units with firm transmission service will be sensitive, since owners of legacy generation will want to make sure that those facilities can continue to deliver energy. An overhaul of the legacy planning model and attendant precepts may require intervention by an oversight authority such as the FERC or NERC to identify the appropriate model assumptions and architecture.

Some interview respondents suggested alternative treatments to avoid renewable curtailments in planning models.

Conclusions

Planning models and/or processes should better reflect the expected real time interactions between and among renewable resources and load.

Description of the Issue

Some consider the requirement to have certain projects selected through a competitive solicitation to be an impediment to renewable energy development. A number of interview respondents claim that transmission owners purposefully avoid developing projects that are subject to competition by instead developing low voltage, local reliability or immediate need reliability projects, and are resistant to invite competition for larger projects in their own service territories. Some believe that competitive processes may be an impediment to backbone transmission development and that there was more efficiency prior to Order 1000. Others are of the view that the requirement that certain projects must be subject to competition is a victory, enabling alternative solutions beyond what would be provided by incumbent transmission owners, which they assert can be done more cheaply than the load serving entity. Most would agree that Order 1000 has not done the job that was intended.

INTERVIEW QUOTE:

"Not a fan of competitive bidding in transmission space. Order 1000 is a solution looking for a project. Hard to get more cooperative planning and more transmission done when people are looking after their own interests. Difficult space to do competitive bidding on a fair basis."

– *Transmission Developer*

Several respondents expressed words of caution that transmission expansion through competitive processes is not likely to produce the optimized grid expansion that is needed. Though there are exceptions, typically with competition, cost is a primary determinative factor, and often, the least cost solution is selected. The current competitive process may result in the placement of many band aids and not leading to the vision of the future or an efficient, optimized transmission grid. The cheapest near-term solution is often not the optimal solution and may not be the cheapest solution in the long run.

Relevant RTO Processes (from Appendix B)

MISO

MISO does not hold competitive solicitations to select developers for projects where Order 1000 permits TOs to a retain a ROFR (upgrades;[80] local transmission projects with costs that are not shared regionally; and certain immediate need reliability projects.) As such, those projects are assigned to the TO. MISO has held solicitations for new transmission projects selected through the MTEP process (e.g., the Duff Coleman and Hartburg-Sabine projects). In the July 2020 FERC order noted above, the Commission also accepted a MISO proposal to exclude certain baseline reliability projects with an immediate need that also qualify as MEPs from the competitive solicitation process.[81]

SPP

SPP held a solicitation for the Walkemeyer project in 2015, but the project was ultimately cancelled. SPP recently approved a competitive project in January 2021, and there are others pending. Like MISO, SPP excludes immediate-need reliability projects with need-by dates of three years or less

80 In Order No. 1000-A, FERC defined an upgrade as an "improvement to, addition to, or replacement of a part of, an existing transmission facility" and clarified that the term upgrade does not refer to an entirely new transmission facility. Order No. 1000-A at P 426.

81 Midcontinent Independent System Operator, Inc., 172 FERC ¶ 61,095 (2020).

from the competitive solicitation process. FERC reaffirmed that SPP's immediate-need reliability project exception was just and reasonable in July 2020.[82]

PJM

PJM's transmission planning process is based on a "sponsorship model" where developers propose a range of solutions to the needs "windows" identified in PJM's regional transmission planning process. PJM solicits solutions to identified transmission needs for the short-term and long-lead projects identified in the RTEP though separate solicitation "windows." PJM does not hold competitive solicitations for Immediate-need Reliability Projects[83] which must be in service within three years, a timeframe that does not permit a competitive solicitation though PJM's window process. After PJM identifies a baseline transmission need, including market efficiency, PJM may open a competitive proposal window, depending on the required in-service date (i.e., immediate need reliability projects needed within three years are exempt), voltage level (200 kV+), and scope (e.g., no upgrades or substation work) of likely projects. As of January 1, 2020, transmission owner criteria FERC 715 projects will be included in PJMs competitive solicitations.[84] For policy projects developed under the State Agreement Approach, states may submit a list of prequalified project developers to PJM (referred to as Designation Entities) to construct a public policy project.[85]

Proposed Solutions

Interview respondents were generally of the view that the best solutions arise through holistic centrally coordinated planning and not from solutions that are selected based on least cost. Respondents had varying views of the effectiveness of Order 1000 and what was needed to create the competitive environment Order 1000 sought to enable. Most respondents were skeptical that competition under Order 1000 would lead to the transmission expansion that is necessary for renewable optimization. Many respondents pointed to the failings of the Order, such as the regulations not going far enough to specify required processes for interregional transmission planning (Order 1000 only required interregional coordination), leaving the actual implementation of interregional transmission processes to the discretion of the RTO. As a result, the processes between RTOs are disjointed and ineffective. In addition, since Order 1000 does not remove the ROFR for reliability projects or for projects that are needed within three years, transmission owners have become hyper-focused on these areas where competition can be avoided, ultimately leading to over investment in local reliability and overall suboptimal grid investment.

INTERVIEW QUOTE:

"Competition is resulting [in] putting on a lot of bandaids and not leading to the vision of the future."

– *Investor-Owned Utility*

Respondents fell into three primary camps on whether changes were needed to Order 1000 to integrate competition into transmission planning processes: (1) keep Order 1000 but tweak it; (2) keep Order 1000 but overhaul it; or (3) eliminate Order 1000 completely. In the "keep it but tweak it" camp, respondents were in favor of the Order 1000 process but expressed a need for a more centrally coordinated process with a solicitation for

82 Southwest Power Pool, Inc., 171 FERC ¶ 61,213 (June 18, 2020).

83 An Immediate-Need Reliability Project is a reliability-based transmission enhancement or expansion: 1) with an in-service date of three years or less from the year PJM identified the existing or projected limitations on the transmission system that gave rise to the need for such enhancement or expansion; or 2) for which the PJM determines that an expedited designation is required to address existing and projected limitations on the transmission system due to immediacy of the reliability need in light of the projected time to complete the enhancement or expansion.

84 PJM, 2019 Regional Transmission Expansion Plan, February 20, 2020, at 15. FERC eliminated the FERC 715 TO criteria exclusion in an order on complaint EL 19-61.

85 PJM Answer, Docket No. EL20-10, at 24-25.

solutions. In an economic sense, the advantages of competition are that it places downward pressure on price and increases the chances that innovative solutions (e.g., non-transmission alternatives, advanced technologies, storage, etc.) would be presented. Many expressed concerns over giving transmission owners free reign to build out their systems, unchecked by competitive forces. These respondents expressed support for more prescriptive rules from the FERC specifying the processes for interregional planning as well as how beneficial projects would ultimately be selected, potentially using a common model and revised and expanded benefit metrics calculations. It was generally agreed that the less prescriptive the solicitation, the better. The solicitation should describe the need but give the bidder the flexibility to design and put forward its own vision of a solution.

In the "keep it but overhaul it" camp, respondents voiced that an overhaul of Order 1000 might accomplish objectives of competition more effectively and fairly. Recognizing that the transmission owner has ultimate responsibility for what is built on their system and often views competition in their service territories as an unwelcome intrusion, it was suggested that the overhaul recognize that incumbent utilities should in most cases retain the ROFR and determine what is built on their systems. However, the RTO could identify certain types of projects as meeting the criteria for a competitive solicitation, i.e., those where multiple technologies or pathways could be offered to solve the same problem and a wide range of solicitations is desired; or projects that span multiple transmission owner service territories.

In the "eliminate Order 1000 entirely" camp, most utilities interviewed consider Order 1000 competitive processes a waste of time and resources and believe strongly that they should not be subject to competition in their own service territories. Some renewable developers also held this view. One renewable developer advocated to let the incumbent utilities determine what gets built in their region. It was suggested by several respondents that utilities are best able to fund transmission expansion through regulated cost of service rates and have the best visibility into what should be built on their systems. This view is aligned with the transmission owner perspective that transmission owners are best situated to construct transmission lines, subject to state oversight for cost control for planning processes and should not be subject to competition.

Another important aspect that may be, at least in part, responsible for the lack of success of competition under Order 1000, is the 'chicken and the egg' problem. That is, renewable developers do not want to build renewable generation where there is no transmission to interconnect, and transmission developers do not want to build transmission lines or storage solutions where there is no generation to connect to. Again, more centralized planning could solve this issue. As discussed earlier, the CREZ process provided a holistic view of co-optimized generation and transmission and carried out a competitive solicitation for the specific needs identified in the study. The process is widely acknowledged to have been highly successful.

Conclusions

Competitive processes would benefit from more centrally coordinated planning where resource areas are identified, and infrastructure solutions that address optimal paths to load centers are solicited.

Description of the Issue

> **INTERVIEW QUOTE:**
>
> **"The problem right now is that beneficiaries are not fully paying."**
>
> ***– Renewable and Infrastructure Developer***

Many renewable project developers commented that they cannot access the MISO, SPP, and PJM markets because of the high cost of upgrades necessary for interconnection. Many of the upgrades benefit load as well the interconnecting generator, but there is no agreed upon methodology for equitably allocating a portion of the costs of the upgrades required for generator interconnections to the load that is benefitting. Currently, if an incoming generator (or group of generators) triggers a network upgrade cost, they (or they and other generators in their cluster) are expected to pay for nearly all necessary network upgrades to interconnect their project, even if the associated network upgrades benefits the broader transmission system. Generators, that do not own and operate transmission and have no rate recovery to help finance network upgrade costs, are not well suited to take on the significant financial burden of very high costs for interconnection, which sometimes may cost multiples of the cost of the project.

A given generation facility (e.g., the first or "marginal" facility whose integration would trigger a costly network upgrade) can be assigned hundreds of millions of dollars in network upgrade costs through the generator interconnection process. For example, the New Jersey Offshore Wind Cardiff 230 kV project in PJM received zero costs to attach to facilities, zero direct upgrade costs, $6 million non-direct connection network upgrades, and $918 million of system upgrade costs.[86] Similarly, the Virginia Solar Project, Carson-Suffolk, a 500 kV line between the generation substation and the new switching station in PJM received $19.3 million in interconnection and attachment costs, and $364 million in system upgrades.[87]

MISO is known to assign similarly high network upgrade costs. In the 2017 MISO West February 2017 cluster study, two generation projects, a 45 megawatt (MW) solar project and a 200 MW wind project, yielded $261 million in Affected Systems Costs and $14 million in network upgrade costs.[88] Examples of excessively high network upgrade and affected systems costs are abundant in the generator interconnection process. Project economics frequently cannot support the high upgrade costs and as a result, generators are often forced to drop out of the queue.

There is a need for a cost allocation approach that all stakeholders can support, which should include generators and loads sharing the costs of network upgrades required for interconnection when the upgrade has regional benefits. Further, interconnecting generators that benefit from the upgrade but interconnect after the upgrade, should share in the cost of the upgrade to address free ridership issues after the network upgrade has been constructed. MISO has a Shared Network Upgrades mechanism to address the free rider issue on a limited basis, i.e., generators that benefit from interconnecting after network upgrades were funded by a previous interconnecting generator. Some RTOs assume projects over a specific voltage have some regional benefit, such as MISO and SPP. But these approaches do not necessarily allocate to load commensurate with benefits and

86 PJM. (February 2020). Generation Interconnection Impact Study Report for Queue Project AE2-251 CARDIFF 230 KV 337.2MW Capacity/1200MW Energy, at 7. https://www.pjm.com/pub/planning/project-queues/impact_studies/ae2251_imp.pdf.

87 PJM. (August 2019). Generation Interconnection System Impact Study Report for Queue Project AE1-173 CARSON- SUFFOLK 500 KV 480 MW Capacity / 800 MW Energy, at 5. https://www.pjm.com/pub/planning/project-queues/impact_studies/ae1173_imp.pdf

88 MISO. MISO DPP 2017 February West Area Phase 3 Study, at x. https://cdn.misoenergy.org/GI-DPP-2017-FEB-West-Phase3_System_Impact_Report_PUBLIC391580.pdf.

miss projects that are of a lower voltage, but that still may provide significant regional benefits. The cost allocation issue will be a difficult one, but a more accurate identification of benefits between load and generators should help. Some are of the view that all costs should be socialized, and others favor an approach that shares costs based on a simple kV and/or dollar threshold.

Relevant RTO Processes (from Appendix B)

MISO | MISO allocates 100 percent of Market Efficiency Projects to load, provided the projects meet the 1.25 B/C ratio. Multi-Value project costs are also regionalized to load. Multi-value projects are projects that serve more than one purpose, i.e., energy policy mandates or laws, economic value across multiple pricing zones with a B/C Ration of 1.0 or higher; or must address at least one transmission issue associated with a project violation and must provide economic value across multiple pricing zones with a B/C Ratio of 1.0 or higher. Further, MISO allocates 100 percent of generator interconnection costs to generators except that 10 percent of those costs are assigned to load if the voltage of the project is 345 kV or greater.

SPP | Upgrades identified in the generator interconnection process are assigned to the transmission customers (generators) and are assumed to be funded by the generators in the ITP process. This would preclude any network upgrade that has been identified in the generator interconnection process from being identified in the ITP as a planning solution. For projects that are identified in the transmission planning process, SPP uses a "Highway/Byway" transmission cost allocation methodology that assigns all costs to load. The Highway/Byway approach assigns 100 percent of all 300+ kV transmission upgrades to the SPP zones on a regional basis using the load ratio share ("LRS") as a percentage of the whole of regional loads of each zone multiplied by the total annual transmission revenue requirement ("ATRR") of the new upgrade. New upgrades in the 100 - 300 kV range are allocated 33 percent to all zones in the region on a LRS basis and 67 percent to the host or local zone; and 100 percent of upgrades under 100 kV are allocated to the local zone. The ATRRs assigned to the zones are collected from their respective transmission customers using the previous year's 12-month coincident peak LRS.

PJM | PJM relies exclusively on the cost causer approach to assign network upgrade costs to interconnecting generators. All projects are treated equally regardless of size, location, or fuel. No portion of costs for upgrades are reimbursed by load. The allocation of costs for a network upgrade will start with the first project to cause the need for the upgrade. Later queue projects receive a cost allocation contingent on their contribution to the violation and are allocated to the queues that have not closed less than 5 years following the execution of the first Interconnection Service Agreement that identified the need for the upgrade.

Proposed Solutions

The question of how best to allocate costs and solve the stalemate in the interconnection queues was met with many interesting and diverse proposals. First, it was generally a consensus view that renewable generation should be studied in clusters, rather than on a project-by-project basis, which is still the practice in PJM. This allows generators to share upgrade costs amongst the cluster and potentially provide a basis to share costs between clusters that benefit from a previous network upgrade. In addition, interconnection cluster studies have shown to reduce study delays that existed when interconnection studies were done project-by-project on a serial basis.

INTERVIEW QUOTE:

"As everyone knows, regardless of whether load pays for a generator interconnection network upgrade or the developer does, at the end of the day it's the customer that pays for it."

– *Renewable Energy Organization*

The primary issue is that generators are being assigned significant network upgrade costs which benefit both load and the interconnecting generators, but currently a large portion of upgrade costs are assigned to the interconnecting generators. Many respondents agreed with the FERC beneficiary pays model, that generation should pay for a portion of the costs of backbone transmission and projects allocated to load serving entities, but not the entire cost. Though most parties agreed that interconnection customers should pay for some portion of the network upgrade costs, they would like to move to a system where load pays network upgrade costs at least roughly commensurate with the benefits it receives from the project. Further, most advocated that there should be a mechanism to recover a portion of the cost for network upgrades from generators that benefit from the upgrade by interconnecting after the network is completed but did not pay for it. The MISO Shared Network Upgrades mechanism that charges a minimum interconnection fee to subsequently interconnecting generators that is remitted back to interconnecting generators that funded the network upgrade may be considered a "best practice" in this regard.

One proposal was based on the benefit to cost ("B/C") ratio. Projects with a B/C ratio in excess of 1.25 are generally determined to be regionally beneficial. The current practice is that if the project did not achieve a 1.25 B/C ratio, the interconnecting generators would either pay the full network upgrade cost or the network upgrade and the project would not be built. In this proposal, in cases where projects did not initially meet the required B/C ratio, the interconnecting generators could agree to fund the portion of the project costs, sufficient to push the project benefits over the 1.25 B/C threshold needed for regional cost allocation. Once the generators payments allow the project to meet the 1.25 B/C threshold, the remaining network upgrade cost (after the generators' contribution) would be paid by load. This proposal was found to have merit by participants.

Another proposal was that when the cluster of interconnecting generators enter the queue, they agree on an upfront fixed not-to-exceed commitment for how much the generators should pay for interconnection in the way of network upgrades. This amount and the upgrades can be included in the regional planning studies to determine if the generators' commitment is sufficient to cause the project to meet the B/C threshold. The proposal might also assume that any assigned network upgrades above a certain voltage limit, e.g., 345 kV, would be fully allocated to load. The generators would remain in the queue as long as their share of any network upgrade amount continued to fall below their fixed commitment. If the project were to meet the required B/C metric, or if the project exceeded the specified kV threshold, all network upgrade costs would be fully allocated to load, and the upfront commitment initially paid by generators would be refunded to the generators and eliminated. If the project did not meet the B/C threshold, it would be funded by the generators' commitments, with any lesser amount required for the upgrade refunded back to the generators. This is essentially a beneficiary pays model, but the upfront generator commitment could help eliminate some of the volatility in the interconnection queues.

Another proposed approach for cost sharing was a "with and without analysis." This approach would require interconnecting generators to pay the lower of the cost of forecast long-term congestion for their point of interconnection, as if no upgrade were being made; or pay the cost of the upgrade that would mitigate long-term congestion. Any additional network upgrade costs above the cost of forecast long term congestion with their project would be paid by load.

Many respondents saw value in the simple rules and thresholds for cost allocation to add transparency and visibility into the cost allocation process. For example, currently MISO shares 10 percent of the costs of any network upgrade for a 345 kV line or greater with load. This approach was generally looked upon as a favorable cost sharing approach, though most found that the MISO sharing percentage was too low, and suggested that a 50 percent assumed benefit to load was more appropriate for network upgrades that exceeded 345 kV. The problem identified with the MISO approach is that it misses low kV upgrades that also have regional benefits.

Conclusions

Cost allocation of generator interconnection upgrades should be shared between load and interconnecting generators at least roughly commensurate with the estimated share of benefits.

4. Closing Remarks

There are efficiencies to be gained by broadening our view of the transmission grid to include a larger geographic view of the system. Efficiencies will be derived from better balanced loads over a broader distance, better interconnected regions, integrating and to some extent standardizing interregional planning processes, and co-optimizing transmission planning and generator interconnection processes. To achieve this outcome, centrally coordinated planning will be required, with a focus on interregional opportunities. At the regional level, efficiencies can be gained by better integrating and co-optimizing local and regional planning processes and generator interconnection processes. At the national and regional level, a planning entity should be identified and tasked with mapping out the least cost energy vision and necessary infrastructure to achieve it, which may require national and state legislative and/or regulatory support to effectuate. Transmission planning at the seams between regions needs to move beyond coordination to co-optimization.

Existing transmission planning processes and models that were designed for legacy base load transmission, and plan for determinative worst-case scenarios, no longer accurately reflect the attributes of our rapidly changing resource mix and advanced technologies, or what we might reasonably expect to occur with the real-time dispatch of units. The increasing integration of renewable resources and grid enhancement technologies may require an entirely new generation of planning models and processes that can capture the interactivity of resources and advanced grid technologies, the full spectrum of benefits that renewable energy resources provide, as well as the uncertainties that are inherently present in electric generation.

Solving the cost allocation issue in the generator interconnection queue will require stakeholder consensus, but many approaches have been identified in this report as paths forward to solve the issue. A reasonable cost sharing methodology should relieve the current log jam in the generator interconnection queues and enable the development of needed backbone transmission capacity to facilitate the interconnection of renewables. This, alone, would reverse many of the negative impacts in the negative feedback loop, mentioned at the beginning of this report. It should also be noted that if transmission planning processes were successful in identifying and constructing the necessary backbone transmission capacity to optimize renewable resources, the cost allocation issue would be less acute. The problem of high network upgrade costs could be addressed by building backbone transmission identified in transmission planning processes or by adopting a more equitable cost sharing methodology between interconnecting generators and load. Either would remove some of the constraints on renewable development, but both are needed for an equitable allocation of cost.

The best models for constructing significant transmission capacity within a short time frame identified in interviews, have proven to be the CREZ model, MVP model, and the NYSERDA Offshore Wind initiative. In most (if not all) of these cases, the need for new transmission infrastructure accompanied a legislative initiative to procure new renewable energy resources. Once the needed infrastructure was identified, a competitive solicitation was held to procure both the generation and the transmission solution. This type of legislated, comprehensive, centrally coordinated, large-scale planning initiative has afforded the best opportunities for robust competition.

APPENDIX A:
Interview Questions

Impediments to renewable development

1. In your view, what aspects of the MISO/PJM/SPP (as appropriate) transmission planning process create obstacles or impediments to wind and solar development? How would you recommend the ISO(s) revise the current planning processes to address those impediments? What are specific near- and long-term steps?
2. What would potential implications be for those revisions? What are the potential pitfalls, likely stakeholder objections, or other obstacles? Are there ways to avoid or mitigate these?

Benefit metrics

3. Do the benefit metrics the ISO use to identify and rank new transmission projects properly identify all of the benefits of new projects? (e.g., Do the benefit metrics consider enough potential outcomes? Look long enough into the future? Accurately assess project costs and benefits?) If not, what benefits are not assessed and how do you think the benefit metrics should be revised?
4. The benefit metrics ultimately drive project selection and cost allocation. Do you think this fact drives certain stakeholders to attempt to influence the benefit metrics of a given project to reduce their potential cost burden? If so, how might this issue be addressed?

Generator interconnection process

5. With respect to including planned generation in the models, in your view, is the limitation to only include planned generation with an executed interconnection agreement (or equivalent) too stringent? If so, how should ISOs balance the needs to accurately identify transmission needs with the fact that only a fraction of the projects in the interconnection queue get built?
6. (For MISO and/or SPP) MISO and SPP have historically under-forecasted the amount of renewable generation that will be built, but have made attempts to address this. Do you think those efforts have been or will be successful? Why or why not?
7. Can the generator interconnection and transmission planning processes be better coordinated? If so, how?
8. Is there a better way to allocate costs, perhaps according to who receives benefits? And if so, what are your recommendations?

Modeling

9. In your view, are the reliability planning models given too much weight or do they “crowd out” transmission development that could address other needs such as economic or public policy? If so, how should ISOs balance the mandatory TPL and local reliability requirements with other transmission needs?

Interregional development

10. What areas of the MISO/SPP or PJM/MISO seam need the most interregional transmission development? Why haven't those needs been addressed?
11. What, in your view, are the biggest impediments to interregional development? How might those impediments be resolved through the planning process?

Other issues

12. Do you have any thoughts on the competitive bidding requirement for cost allocated projects, how they impede the development and approval of larger economic projects, and/or possible solutions?
13. Are there any other issues/barriers/impediments that you would like to highlight not covered in the above? Any other recommendations for changes/improvements?

Wrap up

14. Are there any clear best practices in one ISO/RTO that you recommend for the others (e.g. what is the desired end goal of optimal planning for low-cost energy)?

APPENDIX B:
RTO Planning Processes

MISO

Regional transmission planning process overview

The MISO regional planning process includes a reliability assessment and a "Value Based Planning Process" that "considers a range of potential outcomes identifying opportunities for economic expansions" which meet established planning criteria[89] and are necessary to efficiently meet state and federal energy policy objectives.[90] The regional planning process also assesses whether system enhancements are required to address operational performance issues.

MISO develops an annual Transmission Expansion Plan (MTEP). The MTEP planning cycle identifies system needs and considers potential solutions over short (1-5 years), intermediate (6-10 years), and long-term (11-20 years) planning horizons. Relevant MISO stakeholder committees include the sub-regional planning committees, the Planning Subcommittee, and the Planning Advisory Committee. The MISO system has four planning regions (West, East, Central, and South) and transmission owner plans developed through local planning processes are included in the beginning of each regional planning cycle and considered as potential solutions.[91]

MTEP projects include the following types of projects: [92]

- Baseline Reliability - address reliability violations
- Market Efficiency - improve market efficiency (e.g., reducing congestion, lowering capacity costs, etc.)
- Multi-Value - satisfy one or more transmission needs and meet certain additional criteria
- Generation Interconnection - required for new generator interconnection
- Transmission Delivery Service - required to satisfy a transmission service request
- Market Participant Funded - fully funded by one or more market participants but owned and operated by the transmission owner
- Other - projects that do not qualify as Baseline Reliability Projects, New Transmission Access Projects, Targeted Market Efficiency Projects, Market Efficiency Projects, or Multi-Value Projects. A significant amount of new projects in the MTEP are categorized as "Other" projects.

These project types are described in more detail below. MISO further categorizes these project types into "Bottom-Up", "Top-Down", and "Externally Driven" categories as indicated in Table B1 below.

89 MISO Transmission Planning Manual, Section 4.4.1.
90 MISO Transmission Planning Manual, Appendix K. MISO is the Transmission Planner and Planning Coordinator for the MISO footprint.
91 MISO, Draft 2020 MTEP at 7.
92 MISO Transmission Planning Manual, section 2.3.

Table B1: MTEP Transmission Projects by Type and Category

Project Type	Bottom-Up Project	Top-Down Project	Externally Driven Project
Other	X		
Baseline Reliability	X		
Market Efficiency		X	
Multi-Value		X	
Generator Interconnection			X
Transmission Delivery Service			X
Market Participant Funded			X

Source: MISO, Transmission Planning Manual, Table 2.3.1

Baseline Reliability and Other projects are largely driven by reliability needs proposed by the TOs rather than through the MTEP process and have costs that are not shared regionally. They are referred to as "bottom-up" projects.[93] Conversely, Market Efficiency and Multi-Value projects are "Top-Down" projects that are selected during the regional process and their costs are regionally shared. Generator Interconnection, Transmission Delivery Service, and Market Participant Funded projects are categorized as "externally driven" because these projects are developed through processes outside of the MTEP process and, except for a portion of certain generator interconnection projects with executed interconnection agreements, the costs of externally driven projects are not shared regionally but directly assigned to specific market participants.[94]

Planning Models

Each MISO MTEP planning cycle, which selects both baseline reliability projects as well as projects that address economic and/or public policy goals, starts with regional model development, followed by the identification of potential projects from the local transmission owner planning processes. The reliability planning includes steady-state power flow, dynamic, and first contingency transfer capability (FCITC) analyses of the MISO system.[95]

MISO's Baseline Reliability models typically include all transmission elements rated at 100 kV and above and power-flow models of 2-year, 5-year, and 10-years out from the current year, based on projected system conditions in accordance with the NERC TPL standards. Models for 2-years out and 5-years out are developed both for the system peak demand case and for at least one off-peak case.[96] MISO also performs a steady-state contingency analysis and a steady-state voltage stability analysis.[97]

MISO also performs a Load Deliverability study based on a 5-year out summer peak scenario to assess the system's ability to serve network loads. MISO also performs a Baseline Generator Deliverability study to determine the ability of groups of generators in an area to operate at their maximum capability without being limited by transmission constraints. The Generation Deliverability analysis, based on a 5-year out summer peak scenario, identifies projects that mitigate transmission system constraints that restrict generation output to below established network resource levels.[98]

93 See e.g. MISO, Transmission Planning Business Practices Manual (BPM-020-r19), revision 19, §2.3.1.
94 As noted below, 10% of generator interconnection-driven projects above 340 kV are shared regionally.
95 MISO, Transmission Planning Manual, Appendix L, Section L.2.
96 MISO, Transmission Planning Manual, Section 4.3.3.
97 MISO, Transmission Planning Manual, Section 4.5.1. and 4.2.5.2.
98 MISO, Draft MTEP20, Chapter 2, at 9.

Planning Model Inputs

MISO develops "Futures", or assumptions about the outcomes of key ISO market drivers, before each MTEP cycle and the various Futures are used in the MTEP process.[99] According to the MISO transmission planning manual, Futures are "intended to capture a wide array of potential fleet changes and conditions for long-term transmission planning. With the goal of prudently planning transmission over a 10- to 20-year period, the desire is not to find a single, most likely future definition, but to model a range of Futures that capture reasonable bookends and several points in between."[100] The MTEP20 cycle included four Futures: Limited Fleet Change (LFC); Continued Fleet Change (CFC); Accelerated Fleet Change (AFC); and Distributed and Emerging Technologies (DET).[101] Futures also project alternate forecasts of electrification of the transportation fleet, energy efficiency, new unit construction costs, emissions constraints, retirements, renewable energy development, and regional demand and energy projections.[102]

Forecasts of the size and location of system loads, and the size and location of generation fleet are important because they impact the transmission needs identified. Load forecasts are provided by the load serving entity (LSE) either directly or through the Transmission Owner.[103]

The generation fleets assumed in the planning model are developed with the "Regional Resource Forecasting" (RRF) plan developed for each MTEP Future.[104] According to the MISO transmission planning manual, "the [RRF] process uses the assumptions defined within each Future to economically identify the least-cost portfolio of new supply-side and demand-side resources." Fuel forecasts, new unit construction costs, emissions constraints, retirement assumptions, renewable energy assumptions, and regional demand and energy projections, are also considered.[105] The RRF process uses Electric Generation Expansion Analysis Software to model generation expansion plans.

All existing generators and future generators with a filed Interconnection Agreement and in-service date in the planning horizon are included in the baseline model.[106] MISO's Attachment Y generation retirement processes are also included to account for generator retirements. Generation Interconnection Project costs of network upgrades rated at 345 kV or higher are eligible for 10 percent cost recovery on a system-wide basis. All other costs of generator interconnection network upgrades are charged to the interconnecting generator(s). Generator Retirement and Suspension Studies and System Support Resources (SSR), which retain resources that plan to retire if it would adversely affect reliability, use study cases derived from the MTEP reliability models.[107]

The RRF also identifies any additional generation needed to serve longer-term load growth.[108] According to the MISO transmission planning manual, "sufficient renewable generation will be modeled to meet renewable portfolio standard mandates effective during the applicable planning horizon."[109] However, the MISO RRF models tend to under project renewable resource additions because much more than the RPS requirements are

99 See e.g., MISO, MTEP19 Futures, at 1, https://cdn.misoenergy.org/MTEP19%20Futures%20One-Pager%20(Two-sided)_FINAL301059.pdf.
100 MISO, Draft MTEP20, Appendix E: MTEP EGAS Assumptions Document, at 6. Note that some MTEP studies, such as MTEP21, there are only 3 futures and thus only one point in between.
101 MISO, Draft MTEP20, Chapter 2, at 4. The MTEP20 used Futures from MTEP19 with minimal updates.
102 MISO, Draft MTEP20, Chapter 2, at 4.
103 MISO Transmission Planning Business Practices Manual BPM-020-r22, Section 4.3.3.2.
104 MISO Transmission Planning Business Practices Manual BPM-020-r22, Section 4.4.2.2.1.1.
105 MISO, Draft MTEP20, Chapter 2, at 4.
106 MISO Transmission Planning Manual, Section 4.3.3.2.
107 MISO Transmission Planning Manual, Section 6.2.4.
108 MISO Transmission Planning Business Practices Manual BPM-020-r22, Section 4.3.3.2.
109 MISO Transmission Planning Manual, Section 4.3.3.2.

driving renewable development. For example, MISO noted in the 2020 MTEP report that "Looking ahead as it began the MTEP20 cycle, MISO saw increasing momentum in fleet development and many stakeholders noted how new generation could outpace bookends within the planning horizon."[110] As a result, MISO worked with stakeholders to update these models and additional changes are expected in the MTEP21 Futures.

Network upgrades, such as those identified in the interconnection process, are only included in the MTEP when a market participant or group of market participants or other entities agree to fund the upgrade (e.g., an executed Generator Interconnection Agreement).[111] MISO states in the transmission planning manual that "To ensure sufficient coordination with generation interconnection, MISO will review all network upgrade facilities that may be identified in ongoing generation interconnection studies for impacts on identified system constraints and economic project benefit calculations."[112] However, there is currently no formal process to evaluate the economic benefits of upgrades that result from the generator interconnection process, but certain stakeholders seek to develop such a process within MISO.

Identifying Reliability Needs and Selecting Reliability Projects

MTEP selects two types of reliability projects: the Baseline Reliability Project to address NERC reliability standards and "Other" Projects to address other localized transmission issues.[113] MISO uses a study horizon of 20 years to assess long-term reliability project benefits.[114] The costs for Baseline Reliability expansion projects are allocated to the transmission zone where it is located and collected through the transmission owner annual transmission revenue requirement.[115]

Projects needed to address near-term reliability needs are included in the MTEP. MISO added an "Immediate Need Reliability project" category, to the Market Efficiency Project cost allocation methodology, which FERC approved in July 2020.[116] The Immediate Need Reliability Project is a transmission project that: (1) qualifies as both a Market Efficiency Project and a Baseline Reliability Project; and (2) is necessary to be in service within 36 months of Board approval to address a reliability need.[117]

When project lead times do not require final commitment to a specific solution in the current MTEP cycle, the best solution at the time is selected and placed into Appendix B of the MTEP report. Appendix B projects may be modified, removed, or replaced with other projects in subsequent planning cycles.[118] Baseline Reliability Project costs are not shared regionally but rather 100% of the costs are allocated to the local transmission zone(s) and recovered through an annual transmission revenue requirement.[119]

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110 MISO, Draft MTEP20, Chapter 2, at 8.
111 MISO Transmission Planning Manual, Section 4.5.1.
112 MISO, Transmission Planning Business Practices Manual, BPM-020-r22, Section 4.4.2.5.
113 Affidavit of Jesse Moser, filed April 30, 2020 in Docket Nos. ER20-1723-000 and ER20-1724-000, at 19 ("Moser Aff.").
114 MISO, Transmission Planning Manual, Section 4.4.2.2.2.2.
115 MISO, Transmission Planning Manual, Section 7.1.
116 Midcontinent Independent System Operator, Inc., 172 FERC ¶ 61,095 (2020). According to the Affidavit of Jesse Moser of MISO Director of Economic and Policy Planning "Because lowering the voltage threshold and adding new benefit metrics also increases the likelihood that Baseline Reliability Projects with an immediate need may meet the new Market Efficiency Project criteria, and the Competitive Developer Selection Process potentially adds well over a year to the project's completion, the proposal includes an exception from the Competitive Developer Selection process for those Baseline Reliability Projects that meet the Market Efficiency Project criteria and are needed within 36 months of MISO Board of Directors approval.", filed April 30, 2020 in Docket Nos. ER20-1723-000 and ER20-1724-000, at p. 9.
117 Midcontinent Independent System Operator, Inc., 172 FERC ¶ 61,095 (2020) at P 62.
118 MISO, Transmission Planning Business Practices Manual, BPM-020-r22, Section 4.3.1.3.
119 MISO, Draft 2020 MTEP at 7. See also MISO BPM 20 at Section 2.3.2.2. See Section II of Attachment FF of the MISO tariff.

Market Efficiency and Multi-Value Projects

The Value Based transmission planning processes noted above help identify Market Efficiency and MVP projects, which are determined by the models based on the range of Futures studied.[120] Each project type is discussed in turn below.

Market Efficiency Projects

A Market Efficiency Project (MEP) must meet requirements specified in Attachment FF of the MISO tariff. The project must reduce market congestion to be recommended in the MTEP and to be eligible for regional cost allocation. Projects qualify as MEPs based on cost and voltage thresholds and are developed to produce a benefit-to-cost ratio of 1.25 or greater. One hundred percent of MEP costs are allocated to the benefitting transmission pricing zones based on the Adjusted Production Cost (APC) benefit analysis. Under the “No Loss” provision, zones that are not projected to receive net benefits from the MEP are excluded from the project’s cost allocation.[121] Projects that meet the criteria of both a Baseline Reliability Project and a MEP are allocated according to the MEP allocation methodology.[122] In a July 2020 order noted above, FERC accepted revisions that, among other things, lowered the voltage threshold for MEPs from 345 kV and above to 230 kV and above and added two new benefit metrics.[123]

The benefit metrics used to assess MEPs are listed below: [124]

1. Adjusted Production Cost Savings (APC) savings, calculated as the difference in total production cost of the resources in each MISO cost allocation zone, adjusted for import costs and export revenues, with and without the proposed MEP.

2. Avoided Reliability Project Savings metric, quantified as the savings from reliability projects no longer needed as a result of the MEP.

3. MISO-SPP Settlement Agreement Cost metric, which captures the impact of reduced or increased payments resulting from the MISO-SPP capacity sharing Settlement Agreement.

The three benefit metrics are added together and used to evaluate whether the MISO-Tariff defined 1.25 B/C Ratio is satisfied. FERC approved the last two metrics (i.e., the Avoided Reliability Project Savings and Settlement Agreement metrics) in July 2020 pursuant to a MISO proposal.[125] Total benefits from MEPs are assigned to the Transmission Pricing Zones, and this assignment is used for cost allocation purposes. MISO calculates benefits over the first 20 years of project life after the projected in-service date, with a maximum planning horizon of 25 years from the approval year.[126]

120 MISO Transmission Planning Business Practices Manual BPM-020-r22, Section 4.4.2.5.
121 Transmission Planning Business Practices Manual, BPM-020-r22, Section 2.3.2.3.
122 Transmission Planning Business Practices Manual, BPM-020-r22, Section 7.4.
123 Midcontinent Independent System Operator, Inc., 172 FERC ¶ 61,095 (2020).
124 Moser Aff. at 19.
125 Midcontinent Independent System Operator, Inc., 172 FERC ¶ 61,095 (2020).
126 Moser Aff. at 11.

Multi-Value Projects

A Multi-Value Project (MVP) must satisfy one or more of the criteria listed in Table B2 below.

Table B2: MISO Multi-Value Project Criterion

Criterion 1: reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirements that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation
Criterion 2: multiple types of economic value across multiple pricing zones with a Total MVP B/C Ratio of 1.0 or higher
Criterion 3: MVP must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity reliability standard and must provide economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs (i.e., a B/C Ratio of 1.0 or higher)

Source: MISO Tariff, Attachment FF, § II.C.1, II.C.2, and II.C.3.

If a project qualifies as an MVP and a Baseline Reliability Project or an MVP and MEP, it is designated as an MVP project.[127] MVPs must be brought to the board of directors as a portfolio of projects that bring reasonably similar benefits to all parts of the MISO footprint.

One hundred percent of the costs of MVPs are allocated on a system-wide basis in proportion to the metered energy (in MWh) withdrawn from the transmission system for internal loads and external transactions with sinks other than PJM.[128] The allocation is updated annually based on metered energy by TO.

Public Policy Planning Process

MISO does not have a distinct planning process to identify public policy needs or solutions to address them. Instead, public policy issues evaluated during the MISO Value Based Planning process, and "are typically derived from federal, state, and local laws and mandates that govern the maximum or minimum amount of energy or capacity that can be generated by specific types of resources."[129] In addition, MISO states that it includes all policy requirements within the assumptions that underlie the MTEP futures.

Portfolio Finalization

MISO evaluates the overall portfolio of resources for redundancy, reliability, and performs "no harm" tests, and after consultation with stakeholders, recommends the final portfolio of projects to the MISO Board through the MTEP report. Once approved by the Board, the approved MTEP projects are listed in Appendix A of the final MTEP report. When project lead times do not require final commitment in the current MTEP cycle, the solution selected in the cycle is indicated in Appendix B of the final MTEP report.[130]

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127 MISO Transmission Planning Manual, Section 7.5.4.1.
128 MISO Transmission Planning Manual, Section 7.5.5.2.
129 MISO Transmission Planning Manual, Section 4.4.2.3.
130 MISO Transmission Planning Manual, Section 4.3.1.3.

Review of Recent Transmission Plan

In the draft 2020 MTEP ("MTEP20"), MISO identified $4 billion of projects through the MTEP planning process, which are summarized in the table below.

Table B3: MISO MTEP20 Projects

	Project cost ($ M)	Percent of total cost (%)	Number of projects
Generation Interconnection	$606	15%	100
Baseline Reliability	$755	18%	75
Other	$2,800	67%	340
Total	$4,159	100%	513

Source: MISO, Final MTEP20, "MTEP20 Appendix A Projects, at 15.

The majority of the Other projects in the table address local reliability issues, and 40% of the project costs address reliability needs; 36% of the costs address age and condition; 21% of the costs will address load growth; and the remaining 2% will address other local needs.[131] Forty-five percent of the MTEP20 investment is associated with substation or switching station related construction and maintenance; 37% of the investment is in line upgrades (e.g., rebuilds, conversions, and relocations), 11% of the investment is for new lines on new right-of-way, and the remainder will serve additional needs.

Solicitations

FERC Order 1000 required ISOs to remove an incumbent TO's right of first refusal (ROFR) to construct certain types of transmission projects selected through the regional transmission plan for purposes of regional cost allocation.[132]Order 1000 permits TOs to retain a ROFR for the following project types: (1) upgrades[133]; (2) local transmission projects with costs that are not shared regionally; and (3) certain immediate need reliability projects. As such, MISO does not hold competitive solicitations to select developers for these projects because they are assigned to the TO. MISO has held solicitations for new transmission projects selected through the MTEP process (e.g., the Duff Coleman and Hartburg-Sabine projects). In the July 2020 FERC order noted above, the Commission also accepted a MISO proposal to exclude certain Baseline Reliability Projects with an immediate need that also qualify as MEPs from the competitive solicitation process.[134]

131 Source: MISO, Final MTEP20, October 2020, at 15, "MTEP20 Appendix A Projects".

132 See e.g., Concentric Energy Advisors, Building New Transmission: Experience To Date Does Not Support Expansion of Solicitations, June 2019, for a more detailed discussion of the requirements of Order No. 1000 and transmission solicitations held through June 2019.

133 In Order No. 1000-A, FERC defined an upgrade as an "improvement to, addition to, or replacement of a part of, an existing transmission facility" and clarified that the term upgrade does not refer to an entirely new transmission facility. Order No. 1000-A at P 426.

134 Midcontinent Independent System Operator, Inc., 172 FERC ¶ 61,095 (2020).

Regional transmission planning process overview

SPP's planning process is called the Integrated Transmission Plan (ITP) process, which is used to develop the regional transmission plan called the SPP Transmission Expansion Plan (STEP). The integrated transmission planning process is an annual planning cycle that assesses near- and long-term economic and reliability transmission needs. An ITP assessment is a regional plan designed to meet SPP's reliability, public policy, operational, and economic needs over the planning horizon.[135] With the exception of one incumbent transmission owner (Southwestern Public Service Company), SPP transmission owners do not have a local transmission planning process that is separate from the regional planning process. As noted above, MISO has defined sub-regional and local planning processes. However, in SPP, the local and regional planning processes are evaluated concurrently. The ITP process is carried out with stakeholders through various committees and working groups, such as the Strategic Planning Committee, the Transmission Working Group, the Economic Studies Working Group, the Cost Allocation Working Group, the Regional State Committee (RSC), and the Markets and Operations Policy Committee.

ITP assessments are performed every year to evaluate system needs and possible solutions to address them over a 10-year planning horizon. A longer term 20-year ITP is performed every 3 years. Each annual ITP assessment includes three models: 1) Base Reliability model; 2) SPP Balancing Area (BA) Economic model; and 3) SPP BA Powerflow Reliability model.

As shown in Table B4, the Base Reliability model analyses five load scenarios (Summer, Winter, Light Load, Non-Coincident, and Peak) under the base case projections. The SPP BA Economic model analyses three different "Futures", which serve a similar purpose to the MISO Futures discussed above, in years 5 and 10. The SPP BA Powerflow Reliability model analyses three different futures in years five and 10. SPP Futures include alternative forecasts of load growth, renewable generation, and fuel prices.[136] The Futures cases used in each ITP assessment are determined in a Scoping document before every ITP assessment.

Table B4: SPP ITP Assessment Models

Description	Year 2	Year 5	Year 10	Total
Base Reliability	Summer Winter Light Load Non-Coincident Peak (3)	Summer Winter Light Load Non-Coincident Peak (3)	Summer Winter Light Load Non-Coincident Peak (3)	9
SPP BA (Economic)	One Future (1)	Each Future (1-3)	Each Future (1-3)	3-7
SPP BA Powerflow (Reliability)	One Future's Peak and Off-Peak (2)	Each Futures' Peak and Off-Peak (2-6)	Each Futures' Peak and Off-Peak (2-6)	6-14

135 SPP, Integrated Transmission Planning Manual, July 20, 2017 ("SPP ITP Manual").
136 Ibid.

Planning Models

The base reliability models form SPP's Reliability Needs Assessment and models analyze contingencies per NERC Standard TPL-001.[137] SPP's base reliability model set also includes a short-circuit model for a short-circuit assessment per the NERC TPL standards. SPP may also identify reliability-related operational needs such as voltage issues or thermal loading issues that can't be controlled through re-dispatch and must be managed by either operational procedures or shedding load.[138] The SPP BA Powerflow models are used to model reactive power issues and the P0, P1, and P2.1 planning events per NERC TPL standards.[139] Reliability needs are evaluated for possible reclassification as economic needs during or after the reliability needs assessment.[140] The reliability models dispatch generation, including wind and solar generation, based on whether the resources have long-term firm transmission service. Additionally, In the base reliability models, all entities are required to meet their non-coincident peak demand with firm resources.[141]

Planning Model Inputs

The first step in the annual ITP assessment is developing a Study Scope document do develop certain assumptions, such as futures, and methodologies. The Study Scope document is reviewed and approved by the Economic Studies Working Group (ESWG) and Transmission Working Group (TWG).[142]

Each SPP load serving entity submits a non-coincident load forecast to SPP[143] and the load forecasts are based on the median (i.e., 50/50) non-coincident load forecast of a normal or similarly shaped distribution curve.[144]

According to the SPP ITP manual, generation resources, and the associated upgrades required for their interconnection, are included in the base reliability model if any of the following requirements are met:[145]

1. The resource is existing and in service.
2. The resource has an effective Generator Interconnection Agreement (GIA), not on suspension, and has approved long-term firm transmission service with an effective transmission service agreement.
3. The resource is approved by the TWG as meeting the requirements detailed in the Waiver Requests section of this manual.
4. The resource has been identified by SPP as necessary to solve a model and is approved for inclusion by the TWG, with considerations such as: resources that are in the generator interconnection queue for study; resources with an effective Generator Interconnection agreement; resources have been included in an approved SPP-developed resource plan.

Planned resources and associated transmission service requests that are not in service but have a high probability of going into service can request to be included in the base reliability model.[146] Resources that have been mothballed or are planned for retirement must be submitted into SPP's modeling system for their retirement to be accounted for in the base reliability model. Note that, like MISO, only resources with executed interconnection agreements are considered in the transmission planning models.

137 SPP ITP Manual, Section 4.2.1.
138 SPP ITP Manual, Section 4.4.2.
139 SPP ITP Manual, Section 4.2.2.
140 SPP ITP Manual, Section 4.2.
141 SPP 2020 ITP Assessment Report, October 2020, at 11.
142 SPP ITP Manual, Section 1.4.
143 SPP, MWDG Model Development Procedure Manual, v 4.0,2020 https://www.spp.org/Documents/59885/SPP%20Model%20Development%20Procedure%20Manual%202020%20v4.0.docx.
144 SPP, MWDG Model Development Procedure Manual, v. 4.0, 2020, at 16.
145 SPP IT Assessment Manual, Section 2.1.1.
146 SPP, ITP Manual, section 2.1.1.

Similar to the issues experienced in the MTEP transmission planning process, SPP noted in its 2020 ITP assessment report that prior ITP assessments did not assume sufficient renewable generation to assess transmission needs, stating "Previous ITP assessments have been conservative in forecasting the amount of renewable generation expected to interconnect to the grid. When the studies were completed, installed amounts had nearly surpassed 10-year forecasts." [147]

SPP acknowledged that inaccurately low projections of renewable generation development can result in delayed transmission investment, "Overly conservative forecasts can lead to delayed transmission investment, contributing to persistent congestion. For example, the 2019 economic needs assessment identified five of the ten highest congested flowgates from the 2018 Annual State of the Market Report."[148] According to SPP, "The 2019 ITP assessment used updated methods to better forecast renewables development, which will allow the region to proactively build the infrastructure needed to alleviate congestion and provide access to less expensive energy."[149]

Wind and solar generation development in the base reliability and economic models is based on state renewable policy standards (RPS) for the utilities in the SPP footprint. The percentages in Table B5 reflect the mandate or goal for each utility, and the models add wind and solar generation to meet these objectives.

Table B5: SPP ITP Renewable Portfolio Standards by State

State	Goal or Mandate?	Generation Type	Capacity or energy based?	Percentage		
				Year 2	Year 5	Year 10
Kansas	Goal	Both	Capacity	20	20	20
Minnesota	Mandate	Both	Energy	20	20	25
Missouri	Mandate	Both	Energy	15	15	15
Montana	Mandate	Both	Energy	15	15	15
North Dakota	Goal	Wind	Energy	10	10	10
New Mexico	Mandate	Both	Energy	15	15	15
South Dakota	Goal	Both	Energy	10	10	10
Texas	Mandate	Both	Capacity	5	5	5

Source: SPP, ITP Manual, Table 2.

States that do not have an RPS (i.e., are not included above) are assumed to have no RPS requirement in the forecast period. However, in practice SPP has not found it necessary to add wind and solar resources to meet state RPS goals because the planned addition of wind and solar resources have been sufficient to meet RPS goals.

The transmission topology used in the base reliability models is the existing transmission system and any upgrades or facilities that are included in the SPP Transmission Expansion Plan (STEP) and have been approved for construction with a notification to construct. This includes upgrades identified through the generator interconnection process.[150] The base reliability model also includes the upgrades required to interconnect the "future generation resources" added in the model. The SPP base reliability models also include long-term point-

[147] SPP, 2020 Integrated Transmission Planning Assessment Report, October 2020, at 2.
[148] SPP, 2020 Integrated Transmission Planning Assessment Report, v.1, October 2020, at 2.
[149] SPP, 2019 ITP, at 3.
[150] SPP, ITP Manual, Section 2.1.4 and note 12.

to-point and network service agreements, which will result in a change in the generation dispatch for the defined source and sink of the service and will vary by season, year, and generation type.[151] The reference forecast for fuel prices (e.g., natural gas, oil, uranium, coal, etc.) and associated transportation costs is provided by a third-party vendor. The futures developed may use an alternative fuel price forecast to the reference case.[152]

Any reliability needs identified through the Reliability Needs Assessment must be addressed in the ITP process. SPP selects projects based on various benefit metrics and those metrics are used to allocate the costs of any new transmission projects.

SPP uses a “Highway/Byway” transmission cost allocation methodology, that assigns 100% of all 300+ kV transmission upgrades to the SPP zones on a regional basis using the load ratio share (LRS) as a percentage of the whole of regional loads, of each zone multiplied by the total annual transmission revenue requirement (ATRR) of the new upgrade.[153] New upgrades in the 100 - 300 kV range are allocated 33% to all zones in the region on a LRS basis and 67% to the host or local zone. One hundred percent of upgrades under 100 kV are allocated to the local zone. The ATRRs assigned to the zones are collected from their respective transmission customers using the previous year’s 12-month coincident peak LRS.

Project costs are allocated to SPP regions based on the benefits received (e.g., load ratio share) according to different methodologies pursuant to the SPP Benefits Calculations Manual. Two benefit metrics are used to allocate benefits of mandated reliability projects – a “System Reconfiguration” metric and a LRS metric. This allocation shown in Table B6 below is used to allocate the benefits of mandated reliability projects, which are assumed to have a B/C Ratio of 1.0.[154]

Table B6: SPP Benefit Allocation of Mandated Reliability Projects

Reliability Upgrade kV	Allocation of Benefit
> 300 kV	1/3 System Reconfiguration, 2/3 Load Ratio Share
100 - 300 kV	2/3 System Reconfiguration, 1/3 Load Ratio Share
< 100 kV	100% System Reconfiguration

Source: SPP Benefits Metrics Manual, Section 6.2.1.

The System Reconfiguration method “measures the incremental flows shifted onto the existing transmission system during an outage of the reliability upgrade being evaluated.”[155] According to SPP, this measure is a proxy for how much the reliability upgrade reduces flows on the rest of the system.

The SPP tariff requires SPP to evaluate the reasonableness of the Highway/Byway cost allocation methodology at least once every six years.[156] This review is called the Regional Cost Allocation Review (RCAR), and the most recent RCAR was published in 2016 (RCAR II).[157] This RCAR report, among other things:

151 ITP Manual, Section 2.1.2.
152 SPP, ITP Manual, Section 2.2.1.7.
153 SPP Tariff, Attachment J, Section III.D.
154 SPP Benefits Metrics Manual, Section 6.2.1.
155 SPP Benefits Metrics Manual, Section 6.2.1.
156 SPP Tariff, Attachment J, Section III.D.1. SPP previously conducted this study every three years but in 2017, FERC accepted a proposal to conduct the RCAR every six years (Sw. Power Pool, Inc., 160 FERC ¶ 61,138 (2017)).
157 SPP Regional Cost Allocation Review (RCAR II), July 11, 2016, Section 2.1. https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf.

1. Develops and recommends methodologies to determine the current and cumulative long-term equity/inequity of the currently effective cost allocation for transmission construction/upgrade projects on each SPP Pricing Zone and/or Balancing Authority.
2. Develops a recommendation regarding a threshold for determining an unreasonable impact or cumulative inequity on an SPP Pricing Zone or Balancing Authority.
3. Develops a list of possible solutions for SPP staff to study for any unreasonable impacts or cumulative inequities on an SPP Pricing Zone or Balancing Authority.

Per the SPP tariff, any transmission provider that believes that it has an imbalanced cost allocation may request relief through the Markets and Operations Policy Committee.[158]

Market Efficiency Project Planning Process

The baseline reliability model and the SPP BA Economic Model are used to identify MEPs, which are commonly referred to as "Economic projects" in SPP. The SPP BA model is an hourly production cost model and separate economic model simulations are performed for the various sets of futures assumptions. Economic models are developed for years 2, 5, and 10 of the ITP assessment planning horizon.

The incremental units SPP includes in the base reliability model are *not* included in the Economic models.[159] SPP uses resource expansion software to add conventional resources as necessary to meet resource adequacy requirements based on assumed specifications for new conventional units and the wind and solar resource additions assumed in the futures. The resource expansion software will not build renewable resources.[160]

Identifying economic needs and selecting Market Efficiency Projects

SPP's economic needs assessment identifies the need for economic transmission projects through the economic models, which indicate the constraints causing the most congestion and the costs of managing those constraints through redispatch. According to the SPP ITP Manual, the constraints identified in the economic models serve as the starting point for constraints to be considered as economic needs for the study.[161]

Binding constraints are first ranked from the highest to lowest congestion score, which is the product of the constraint's average shadow price and the number of hours that constraint binds. Under certain conditions, SPP can also identify flowgates that create persistent, economic-related operational needs.[162] Economic solutions are evaluated based on criteria developed by SPP and stakeholders that are described in the study scope. Solutions mitigating economic needs are ranked by their cost effectiveness, net APC benefit and multivariable qualitative benefits for each need or set of needs and categorized into one or more of the following groupings:

- Cost effective: Solutions with the lowest cost with respect to the congestion relief they provide on individual flowgates will be selected.
- Highest net APC benefit: Solutions with the highest difference between one-year APC benefit and one-year project cost will be selected.
- Multi-variable: Top-ranking projects in the other two groupings, as well as qualitative benefits that the other groupings may not capture, will be considered when selecting projects.[163]

All solutions, regardless of the type of need they address, are evaluated based on a one-year B/C Ratio and 40-year net present value (NPV) B/C Ratio.[164] Other metrics can be considered, including, but not limited to, one-year project cost, APC benefits, overlap with other projects, and the ability to address multiple economic needs,

158 SPP Tariff, Attachment J, Section III.D.1.
159 SPP ITP Manual, Section 2.2.1.4.
160 SPP ITP Manual, Section 2.2.2.1.2.
161 SPP ITP Manual, Section 4.1.
162 SPP ITP Manual, Section 4.4.1.
163 SPP ITP Manual, Section 6.1.1.
164 SPP ITP Manual, Section 5.3.1.

and routing or environmental concerns.[165] MEPs must have at least a 0.5 one-year B/C Ratio or a 1.0 40-year net present value (NPV) B/C Ratio to be considered in the ITP portfolio and the solution is assumed to be in-service in year 5 of the forecast horizon to calculate the 40-year NPV B/C Ratio.[166] The costs of MEPs are allocated according to the Highway/Byway methodology noted above.

Public Policy Planning Process

As of April 2015, there were no "policy" projects with a notification to construct (NTC) and all projects were classified as either "reliability" or "economic."[167] However, projects that address public policy needs are ranked based on their APC benefit relative to a conceptual cost estimate for each project. APC benefits are re-estimated for top-ranking solutions that address public policy needs based on updated cost estimates.[168]

According to the SPP ITP Manual, "Needs driven by public policy arise if the economic simulations identify conditions on the system that keep a utility from meeting its regulatory or statutory mandates and goals as defined by the renewable policy review and/or future specific public policy assumptions identified in the study scope."[169] During the cost allocation process, the benefits of meeting public policy goals are allocated to zones based on their share of unmet state renewable energy mandates or goals that drive the need for the policy project.[170]

Portfolio Finalization

The final step in the ITP assessment is to select need-by dates, or "stage", each project. Each project type (e.g., reliability) has its own methodology to develop need-by dates, which are based on the model results from years 2, 5, and 10.[171] All upgrades identified in the ITP assessment that solve year 2 violations are initially staged for an in-service and need-by date in the season when the violation occurs.[172] For upgrades that resolve reliability needs projected in the year 5 and 10 models, SPP uses linear interpolation of thermal loading or the per-unit voltage value to determine a need-by date for staging.[173] After the portfolios that address economic, reliability, operational, and policy needs are identified, they are evaluated for redundancy and consolidation.[174] The final portfolio of projects is also evaluated against the futures used over a 40-year period.

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165 SPP ITP Manual, Section 6.1.1.
166 SPP ITP Manual, Section 5.3.1.
167 SPP Benefits Manual, Section 9.2.
168 SPP ITP Manual, Section 6.1.3.
169 SPP ITP Manual, Section 4.3.
170 SPP, RCAR II, Section 3.7.
171 SPP ITP Manual, Section 6.3.
172 SPP ITP Manual, Section 6.3.2.
173 SPP ITP Manual, Section 6.3.2. For example, a reliability violation that occurs in year 5 summer peak model will be year 5 summer peak will be staged between the summer peaks of year 2 and year 5, based on a linear interpolation between the year 2 and year 5 summer-peak models.
174 SPP ITP Manual, Sections 6.1.5 and 6.2.

Review of Recent SPP Transmission Plan

According to the 2019 SPP ITP, a driver of ITP projects is "reducing price separation in the SPP marketplace, which is caused by congestion on the transmission grid."[175] SPP attributes this need to "Rapid renewable expansion [that] has caused increasing pricing disparity between the western and eastern portions of the SPP system. These disparities have created higher average costs for eastern load centers because of congestion and lack of access to less expensive generation."[176] A summary of projects selected in SPP's 2020 transmission expansion plan is listed below.

Table B7: 2020 SPP Transmission Expansion Plan – summary of upgrades

Project type	Investment ($ M)	Percentage of total
Approved projects from the 20-Year Assessment	$560	11.4%
Approved projects from the ITP Assessment	$2,683	54.7%
Approved High Priority Upgrades	$702	14.3%
Transmission Service	$731	14.9%
Generator Interconnection	$211	4.3%
Sponsored Projects	$14	0.3%
Total	**$4,901**	**100%**

Source: SPP, 2020 SPP Transmission Expansion Plan Report, at 4.

Solicitations

SPP held a solicitation for the Walkemeyer project in 2015, but the project was ultimately cancelled. Like MISO, SPP excludes immediate-need reliability projects with need-by dates of three years or less from the competitive solicitation process. FERC reaffirmed that SPP's immediate-need reliability project exception was just and reasonable in July 2020.[177]

175 SPP, 2019 Integrated Transmission Planning Assessment Report, v.1, November 6, 2019, at 2.
176 SPP, 2019 Integrated Transmission Planning Assessment Report, v.1, November 6, 2019, at 2.
177 Southwest Power Pool, Inc., 171 FERC ¶ 61,213 (June 18, 2020).

Regional Transmission Planning Process Overview

PJM's Regional Transmission Expansion Plan (RTEP) consists of three major studies: the Baseline Reliability analyses; the Market Efficiency analyses; and Operational Performance studies. The RTEP does not have a distinct planning process to identify the need for public policy projects. The RTEP is 24-month planning process with two overlapping 18-month planning cycles that are based on a 15-year planning horizon.[178] The 18-month planning cycles are used to identify and develop shorter lead-time reliability-related transmission upgrades. The Transmission Expansion Advisory Committee (TEAC) and three Subregional RTEP Committees (Mid-Atlantic, Southern, and Western) are the stakeholder committees that develop the RTEP along with PJM. RTEP baseline regional plans are developed and approved each year.[179] The RTEP planning process includes both near-term (5 years out) and long-term (years 6 through 15) assessments of the transmission system.

According to the PJM RTEP manual, there are three "planning paths" that culminate in the PJM RTEP base case: 1) Regional and subregional RTEP projects for baseline upgrades; 2) Supplemental Projects; and 3) Customer-Funded Upgrades. The 15-year RTEP planning process results in a regional plan that includes these and other types of projects:[180]

1. Baseline reliability upgrades
2. Market Efficiency driven upgrades
3. Operational Performance issue driven upgrades
4. FERC Form No. 715 projects
5. Public Policy Projects (not developed through RTEP process)
6. Supplemental Projects
7. Customer-Funded Upgrades including Network Upgrades associated with the Generator Interconnection, Local Upgrades, or Merchant Network Upgrades

The baseline upgrades included in the RTEP are identified and modeled in the reliability and market efficiency planning processes described below. The RTEP also develops projects to operational needs, which are also discussed below. Finally, the process for including public policy projects in the RTEP, which are not developed through the RTEP process, is discussed.

Planning Models

The RTEP ensures that the PJM system has no projected planning criteria violations as defined by the requirements of the North American Electric Reliability Corporation's Transmission Planning (TPL) Reliability Standards.

The PJM RTEP base case planning models include, but are not limited to, a base Powerflow model, and separate base models to perform short circuit and stability studies, load deliverability studies, and generator deliverability

[178] PJM's RTP process is governed by Schedule 6 of the PJM Operating Agreement and Attachment M-3 of the PJM Tariff.
[179] PJM RTEP Manual, Section 2.2.
[180] PJM Manual 14-B, PJM Region Transmission Planning Process, Revision: 47, Effective Date: September 1, 2020, Section 2.1 ("PJM RTEP Manual").

studies. The base case identifies violations of applicable NERC planning standards, and Transmission Owner Reliability Planning Criteria that are filed through FERC Form 715 filings.[181]

The 5-year or "near-term" RTEP baseline analysis completed as part of the RTEP planning cycle includes a review of applicable reliability planning criteria on all bulk electric system facilities. The RTEP process develops solutions to any planning criteria violations identified in the studies. The annual review includes an analysis, with sensitivities, of the system at peak load for either year 1 or year 2, and for year 5.[182] A baseline system without any criteria violations is developed for the 5-year baseline, which is used for subsequent interconnection queue studies.

Reliability Models

The annual RTEP near-term reliability review has seven steps:[183]

1. Develop a Reference System Powerflow Case
2. Baseline Thermal
3. Baseline Voltage
4. Load Deliverability – Thermal
5. Load Deliverability – Voltage
6. Generator Deliverability – Thermal
7. Baseline Stability

Baseline upgrades include projects to address reliability issues, operational performance issues, FERC Form No. 715 criteria, and economic public policy planning for facilities 100 kV and above.[184] The baseline model ensures the PJM system complies with applicable NERC, PJM, and local reliability and planning criteria. Baseline upgrades at voltages of 230 kV and above are reviewed by the TEAC categorized as "Regional RTEP Projects", and baseline upgrades below 230 kV are reviewed by the applicable Subregional RTEP Committee and referred to as Subregional RTEP Projects.[185]

The RTEP planning cycle also includes a longer-term reliability study, which begins in the second year of the two-year RTEP cycle, that evaluates the updated 5-, 7-, and 10-year out planning years. According to the PJM RTEP manual, "The purpose of the long-term review is to anticipate system trends which may require longer lead time solutions."[186]

Supplemental Projects

Supplemental projects are not regionally allocated or developed through the RTEP process however, as noted above, they are included in the RTEP as a baseline reliability project. A Supplemental Project is a "transmission expansion or enhancement that is not needed to comply with PJM reliability, operational performance, FERC

181 PJM RTEP Manual, Attachment D.
182 PJM RTEP Manual, Section 2.2.3.
183 PJM RETP Manual, Section 2.2.3.
184 The PJM RTEP may include facilities nominally under 100 kV that are under PJM's operational control. PJM RTEP Manual, Section 1.1.
185 PJM RTEP Manual, Section 1.2.
186 PJM RTEP Manual, Section 2.3.16.

Form No. 715,[187] economic criteria or State Agreement Approach projects. Supplemental Project drivers, or needs, are 'supplemental' to those Operating Agreement specified criteria."[188] Supplemental Projects in PJM have been the subject of complaints with FERC. In September 2018, in an order on a complaint related to Supplemental Projects, FERC found that Order No. 890 did not require PJM incumbent transmission owners to transfer their local planning process over to PJM. Instead, the Commission found that incumbent transmission owners retain primary authority over planning local or Supplemental Projects.[189]

Supplemental Projects, which are not limited to a particular voltage, are planned through Attachment M-3 of the PJM Tariff and could include projects that: 1) expand or enhance the transmission system; 2) address transmission owner zonal reliability issues; 3) maintain the existing transmission system; 4) comply with regulatory requirements; or 5) implement Transmission Owner asset management activities.[190]

Although Supplemental Projects are included in the RTEP, they do not require PJM Board approval. If PJM finds through the RTEP process that a Supplemental Project interacts with an identified violation, system condition, economic constraint, or public policy requirement posted on the PJM website, PJM notes the potential interaction on its website.[191] If PJM finds that a baseline upgrade would more efficiently or cost-effectively address a need met by a Supplemental Project, PJM will discuss the interaction with the sponsoring transmission owner and stakeholders and submit the proposed baseline upgrade to the PJM Board for approval.[192] However, if PJM does so, the sponsoring transmission owner is not required to withdraw the Supplemental Project, and provided certain conditions are met, that transmission owner can proceed with the Supplemental Project and PJM will include it in the next RTEP base case.[193]

Inputs to Planning Models

Prior to conducting the studies in the reliability planning process, a common set of planning assumptions is developed, which are vetted and endorsed by the TEAC.[194] Next, PJM develops a near-term reliability analysis based on several power flow cases that are five-years out (the base case), where near-term reliability violations are identified, reviewed, and ultimately submitted to the PJM Board for approval.

Load forecasts are based on PJM's annual load forecast, which provides energy and peak load projects for the 15-year forecast period. PJM updated the methods in the 2020 load forecast and going forward will calibrate the independent variables used against other variables, analyze distributed solar generation on a more granular level, and include an explicit adjustment for plug-in electric vehicles.[195]

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187 The transmission owner's process specific to the Transmission Owner's zone, including projects that could address the end of useful life of existing facilities, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes, may be memorialized as Transmission Owner planning criteria under the Transmission Owner's FERC Form No. 715. See PJM RTEP Manual, Section 1.3.3.

188 PJM RTEP Manual, Section 1.1.

189 Monongahela Power Company et al., 164 FERC ¶ 61,217 (September 26, 2018) at P 13. Specifically, the Commission explained that "[w]hen transmission owners participate in an RTO, the Commission did not require them to allow the RTO to do all planning for local or Supplemental Projects… The PJM Transmission Owners therefore may retain primary authority for planning local Supplemental Projects…" Id.

190 PJM RTEP Manual, Section 1.1.

191 PJM RTEP Manual, Section 1.4.2.1.

192 PJM RTEP Manual, Section 1.4.2.2.

193 PJM RTEP Manual, Section 1.4.2.2.

194 PJM RTEP Manual, Section 2.3.17.

195 PJM, 2019 RTEP, at 37.

According to the PJM RTEP manual, each case is developed from the most recent set of Eastern Reliability Assessment Group system models, which are revised as needed to incorporate all of the current system parameters and assumptions. These assumptions include current loads, installed generating capacity, transmission and generation maintenance, system topology, and the most recently finalized Local Plans and firm transactions.[196]

If no capacity is needed to meet the planning reserve margin, queue generators in earlier stages of the interconnection queue process may also be included. According to the RTEP manual, PJM employs the following guidelines regarding when to include the planned projects or upgrades in the annual RTEP base case:[197]

Baseline upgrades are included in the next RTEP base case once the baseline upgrade is approved by the PJM Board.

1. Customer-Funded Upgrades (e.g., pursuant generator interconnection requests) are included in the next RTEP base case once the customer has executed one or more PJM agreements[198] or if the completion of the RTEP requires inclusion of New Service Queue Requests with an executed Facilities Study Agreement in order to meet the new load requirements resulting from normal forecasted load growth.
2. A Customer-Funded Upgrade may be removed from the RTEP base case if an agreement is cancelled or terminated, provided such upgrade is not required by a subsequent New Services Queue Request with an executed service agreement.
3. Supplemental Projects will be included in the next RTEP base if they are included in the Local Plan.
4. Subject to certain conditions, projects may be excluded if a regulatory siting authority denies the project through a final regulatory order that exhausts all regulatory processes that would enable the project to move forward.

Generation retirements will not affect the study results for any generation or merchant transmission project that has received an Impact Study Report. In such cases, the generator retirements are applied in the next baseline update.[199]

The results of capacity market auctions are used to help determine the amount and location of generation or demand side resources included in the reliability models. Generation or demand side resources that cleared any locational capacity auction are included in the reliability models. But, generation or demand side resources that either do not bid or do not clear in any capacity auction will not be included in the reliability models.[200] Any planned generators in the queue that have executed Interconnection Service Agreements can be used to alleviate constraints.[201]

196 PJM RTEP Manual, Section 2.3.4.
197 PJM RTEP Manual, Section 1.4.3.
198 The interconnection customer must have an executed Interconnection Service Agreement, Upgrade Construction Service Agreement, Wholesale Market Participation Agreement or Transmission Services Agreement with PJM to be included.
199 PJM, RTEP Manual, Section 2.2.
200 PJM RTEP Manual, Section 2.3.4.
201 PJM RTEP Manual, Section 2.3.4.

Modifications to planned generation or changes in transmission topology during the planning cycle can trigger restudy and the issuance of a baseline addendum or a "retool" study. Additionally, generation projects seeking interconnection that withdraws from the interconnection queue may cause restudy and potentially an addendum to the affected baseline analyses.[202]

According to the PJM RTEP Manual, "Requests for interconnection of new generators or transmission facilities, while not the sole drivers of the PJM Region transmission planning process, are a key component of the RTEP."[203] The 5-year baseline system, without any criteria violations, is used in interconnection queue studies.[204] If prior baseline RTEP upgrades can be delayed because of a new interconnection request, the projects responsible for the upgrade deferrals will be credited for the benefits of the delayed need for the baseline upgrades.[205] Other inputs to the RTEP reliability planning process include annual PJM operational reports and other operational assessments, load serving capacity expansion plans, generator interconnection requests, and long-term firm transmission service requests.[206] The RTEP also considers long-term transmission service agreements.

Identifying Reliability Needs and Selecting Reliability Projects

Local reliability projects are identified by TOs in the local planning process and PJM uses the regional reliability models to identify any regional reliability issues. Potential reliability violations that the reliability planning models identified during the first year are validated, and proposed solutions are refined during the second year of the 24–month planning cycle.[207] Baseline reliability needs associated with near-term projected NERC, regional, or local reliability requirements must be addressed or studied further. Except for reliability-driven projects that are planned on an accelerated basis to reduce congestion, there is no B/C threshold ratio for projects needed to address reliability concerns. The RTEP classifies projects that address reliability issues with a projected need within the following three years as Immediate-Need Reliability Projects. Immediate-Need Reliability Projects are reliability-based projects, enhancements, or expansions with: 1) an in-service date of three years or less from the year PJM identified the existing or projected limitations on the transmission system that gave rise to the need for such enhancement or expansion; or 2) for which PJM determines that an expedited designation is required to address existing and projected limitations on the transmission system due to immediacy of the reliability need in light of the projected time to complete the enhancement or expansion.[208] Like MISO and SPP, PJM does not hold competitive solicitations windows for Immediate-Need reliability projects and designates the transmission owner as the project owner and developer of such projects.

Simulations in the reliability planning process perform cost/benefit analyses of advancing baseline reliability projects. Initial simulations are conducted for the current year, following year, and 5-years out using the "as is" transmission network topology with and without the RTEP candidate project, and indicate whether the project has caused significant historical or simulated congestion costs. Projects that reduce or eliminate congestion may be selected as candidate on an accelerated timeline.[209]

202 PJM RTEP Manual, Section 2.3.3.
203 PJM RTEP Manual, Section 2.2.
204 PJM RTEP Manual, Section 2.1.2.
205 PJM RTEP Manual, Section 2.4.
206 PJM RTEP Manual, Section 2.2.
207 PJM RTEP Manual, Section 2.1.2.
208 See Operating Agreement Schedule 6, § 1.5.8(m)(1). In a June 2020 Order, FERC largely upheld PJM's criteria for excluding Immediate-need Reliability Projects from the competitive solicitation process but directed further modifications to the PJM tariff. See PJM Interconnection, L.L.C., 171 FERC ¶ 61,212 (June 18, 2020).
209 PJM RTEP Manual, Section 2.6.4.

The RTEP includes projects from the following "drivers": baseline reliability upgrades, operational performance; market efficiency; FERC No. 175; public policy requirements; and Supplemental Projects.[210] A project that addresses two or more of these drivers is called a "Multi-Driver Approach Project", which can be developed through a "Proportional" or "Incremental" Multi-Driver Method. The Proportional method combines separate solutions that address reliability, economics and/or public policy into a single transmission enhancement. The Incremental method expands or enhances a proposed single-driver solution that addresses a combination of reliability, economic and/or public policy drivers. Under certain conditions, Customer-Funded upgrades that are not Merchant projects can be incorporated into a Multi-Driver Approach Project.[211]

Reliability Project Cost Allocation

Baseline Transmission Reliability Upgrades are allocated based on a load zone's usage of the reliability project by a PJM load zone relative to the usage by all other PJM load zones. The proportion of the benefits received will be used to determine the percentage cost responsibility to be assigned to the zone.[212]

Regional and Necessary Lower Voltage Facilities with estimated costs of $5 million or more:[213]

- 50% of the cost of the upgrade will be assigned annually on LRS at peak load or withdrawal rights merchant transmission with firm withdrawal rights
- 50% of the cost of the upgrade will be assigned annually on a directionally weighted DFAX methodology[214]

Lower Voltage Facilities with estimated costs of $5 million or more:

- 100% of the cost of the upgrade will be assigned annually on a directionally weighted solution-based DFAX methodology.[215]

Lower Voltage Facilities with estimated costs below $5 million:

- 100% of the cost will be assigned to the zone where the upgrade is to be located.[216]

Market Efficiency Planning Process

The Market Efficiency planning process is used to identify Market Efficiency Projects (MEPs). According to PJM's 2019 RTEP, the market efficiency analysis has the following objectives:[217]

- Determine which reliability-based enhancements have economic benefit if accelerated.
- Identify new transmission enhancements that may realize economic benefit.

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210 PJM RTEP Manual, Section 2.1.
211 PJM RTEP Manual, Section 2.1.1.
212 PJM RTEP Manual, Attachment A, Section A.3.
213 PJM RTEP Manual, Attachment A, Section A.3.1.
214 The term DFAX refers to the distribution factor, which is generally the percentage of power flowing on Element A that will be picked up (or backed down) on Element B as a result of an outage on Element A or a shift on generation. The DFAX methodology uses peak loads to determine the extent to which each transmission zone or merchant facility will use the upgrade to PJM generation to serve load. The allocation for each LDA will be the average of the DFAX allocation and the LDA's LRS at the appropriate peak load. PJM RTEP Manual, Attachment A, Section A.3.1.
215 PJM RTEP Manual, Attachment A, Section A.3.1.
216 PJM RTEP Manual, Attachment A, Section A.3.1.
217 PJM, 2019 RTEP, at 17 and 61.

- Identify the economic benefits associated with reliability-based enhancements already included in the RTEP that, if modified, would relieve one or more congestion constraints, providing additional economic benefit.

The near-term MEP planning process is a 24-month process, consisting of two 12-month cycles which identify approved RTEP projects that may be accelerated or modified. In addition, there is a 24-month planning cycle that allows for sufficient time to identify longer lead-time transmission upgrades.[218] The long-term Market Efficiency planning process evaluates congestion for years 1, 5, 8, 11, and 15. Congestion issues identified during the first year are validated and the proposed solutions are refined during the second year of the 24–month cycle.

Identifying Needs for Market Efficiency Projects

The needs for Market Efficiency projects are identified through metrics designed to measure economic inefficiency, such as historic congestion (e.g., gross congestion, unhedgeable congestion, and pro-rated auction revenue rights) and projected congestion. The economic planning process typically uses the reliability model as an input or "base case" and seeks to identify economic upgrades that will alleviate congestion on the system. Production cost models are used to estimate projected congestion with and without the project in planning years 1 and 5 for potential MEPs and RTEP projects approved in prior planning studies. Constraints considered to have an economic impact include, but are not limited to, constraints that have caused significant historical gross congestion; pro-ration of Stage 1B Annual Revenue Rights; or that are forecasted to have significant congestion.[219]

Selecting Market Efficiency Projects

The B/C ratio for MEPs is calculated as the ratio of the present value of the total annual benefits from the projects and the present value of project costs. Annual benefits estimated over the 15-year planning period, starting with the RTEP year defined as current year plus 5, less benefits for years where the project is not yet in service. MEPs must have a Benefit/Cost (B/C) ratio of at least 1.25 to be included in the RTEP.[220]

PJM calculates the annual benefit of a MEP, known as the "Total Annual Enhancement Benefit" as the sum of two benefit metrics: 1) the Energy Market Benefit; and 2) the Reliability Pricing Market benefit."[221]

The Energy Market Benefit metric uses the production cost model runs noted above and compares the simulations over the RTEP planning with and without the project to identify these benefits. The Energy Market Benefit for Regional Projects (over 230 kV) and Lower Voltage projects are shown below. Several PJM benefit metrics estimate the changes in energy and capacity payments to PJM loads. This differs somewhat from the APC metrics used in MISO and SPP, which evaluate production costs.

218 PJM RTEP Manual, Section 2.1.3.
219 PJM RTEP Manual, Section 2.6.
220 PJM RTEP Manual, Attachment E.
221 PJM RTEP Manual, Appendix E, Section E.1.

Energy Market Benefit metrics for Market Efficiency Projects

Regional Projects	0.5*{Change in total energy production costs} +0.5*{Change in load energy payments}
Lower Voltage Projects	Change in load energy payments

Source: PJM RTEP Manual, Attachment E, Section E.1.

The Reliability Pricing Model Benefit is calculated by simulating PJM capacity market outcomes with and without the Market Efficiency project being studied. The Reliability Pricing Model benefits of a MEP calculated for Regional and Lower Voltage projects are calculated as shown below.

Reliability Pricing Model Benefit metrics for MEPs

Regional Projects	0.5*{Change in total system capacity cost} +0.5*{Change in load capacity payment}
Lower Voltage Projects	Change in load capacity payments

Source: PJM RTEP Manual, Attachment E, Section E.1.

Both the Energy Market and Reliability Pricing Model benefit metrics are calculated over the RTEP planning horizon according to the upgrade's assumed in-service date.

Market Efficiency Project Cost Allocation

The costs of MEPs with no reliability benefits are allocated based on the Energy Market Benefits allocated to zones based on the benefits received as follows:

Table B8: Cost allocation of MEPs with no reliability benefits

	Allocation based on Total Energy Market benefits received
Regional Projects	50% allocated on Load Ratio Share and 50% allocated to zones with decreased net load payments
Lower Voltage	100% allocated to zones with decreased net-load payments.

Source: PJM, Market Efficiency Study Process and RTEP Window Project Evaluation Training, October 16, 2018, at 65.

Projects with both baseline reliability benefits and market efficiency benefits are allocated as baseline reliability upgrades according to the methods described above.

Public Policy Planning Process

Although according to PJM's tariff, public policy needs are considered within the reliability and economic planning processes,[222] PJM stakeholder materials indicate that the "State Agreement Approach" and Supplemental Project process are the primary vehicles used in PJM to address transmission needs driven by public policy requirements.[223] Under the State Agreement Approach, one or more states voluntarily agree to be responsible for the allocation of costs of a proposed transmission platform project that addresses state public policy requirements. The project would be included in the RTEP as a public policy requirement project. Project costs would be allocated to customers in the participating states pursuant to a FERC-approved methodology.[224] The state of New Jersey was the first state in PJM to use the State Agreement Approach to facilitate the deliverability of 7,500 MW of offshore wind the state intends to procure by 2035. FERC approved this approach in February 2021.[225]

Other – Operational Performance

The RTEP also addresses whether system enhancements are required to address operational performance issues. According to the RTEP manual, typical operating areas of interest include transmission loading relief, post contingency local load relief warning events, and persistent uplift payments.[226] PJM also performs a probabilistic risk assessment of transmission infrastructure that analyses significant transmission loss events (e.g., due to age).[227]

Portfolio Finalization

After an initial set of RTEP projects upgrades are selected, PJM performs a combined review of the accelerated reliability projects and new MEPs with a B/C ratio of 1.25 or higher to determine the most efficient solution overall, which may result in changes to the initial set of RTEP projects.[228] This final combined review may result in a "hybrid transmission upgrade," which modifies a reliability-based enhancement already included in the RTEP to relieve one or more economic constraints.[229]

Review of Recent Transmission Plan

According to the 2019 PJM RTEP, "new largescale transmission projects (345 kV and above) have become more uncommon as RTO load growth has fallen below one-half of a percent. Aging infrastructure, grid resilience, shifting generation mix, and more localized reliability needs are now more frequently driving new system enhancements."[230] A summary of new projects selected trough the 2019 RTEP is provided in Table B9 below.

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222 PJM Operating Agreement, Schedule 6, sections 1.5.1(a), 1.5.3, 1.5.4(c), 1.5.6(b), 1.5.6(e).
223 PJM, State Agreement Approach, July 7, 2020, at 3, available at https://www.pjm.com/-/media/committees-groups/committees/pc/2020/20200707/20200707-item-11-state-agreement-approach.ashx.
224 PJM Operating Agreement, Schedule 6, Section 1.5.9.
225 PJM Interconnection, L.L.C., 174 FERC ¶ 61,090 (2021).
226 PJM RTEP Manual, Section 2.7.
227 PJM RTEP Manual, Section 2.7.2.
228 PJM RTEP Manual, Section 2.6.6.
229 PJM RTEP Manual, Section 2.6.6., note 3.
230 PJM, 2019 Regional Transmission Expansion Plan, February 20, 2020, at 4.

Table B9: 2019 RTEP projects

	Investment ($ M)	Percent of total
2019 Baseline Projects		
Transmission Owner Criteria	$866	59.4%
Baseline Deliverability	$230	15.8%
Generator Deactivation	$192	13.2%
Operational Performance	$135	9.2%
Market Efficiency	$32	2.2%
Short Circuit	$4	0.3%
Total Baseline Projects*	**$1,459**	**100%**
2019 Supplemental Projects		
Equipment material condition, performance, and risk	$143	37.3%
Operational flexibility and efficiency	$102	26.6%
Customer service requests	$97	25.3%
Infrastructure Resilience	$39	10.2%
Other	$2	0.5%
Total Supplemental Projects	**$383**	

**Including Reliability. Source: PJM 2019 RTEP, Figure 1.10 and p. 50.*

Solicitations

PJM's transmission planning process is based on a "sponsorship model" where developers propose a range of solutions to the needs "windows" identified in PJM's regional transmission planning process. PJM solicits solutions to identified transmission needs for the short-term and long-lead-time projects identified in the RTEP though separate solicitation "windows." PJM does not hold competitive solicitations for Immediate-need Reliability Projects[231] which must be in service within three years, a timeframe that does not permit a competitive solicitation though PJM's window process. The Commission affirmed this in 2020 in an order that directed PJM to file further compliance. After PJM identifies a baseline transmission need, including market efficiency, PJM may open a competitive proposal window, depending on the required in-service date (i.e., immediate need reliability projects needed within three years are exempt), voltage level (200 kV+) and scope (e.g., no upgrades or substation work) of likely projects. As of January 1, 2020, transmission owner criteria FERC 715 projects will be included in PJMs competitive solicitations, per a FERC order in a complaint.[232] For policy projects developed under the State Agreement Approach, PJM explained in an answer to a complaint with FERC about the RTEP process that states may submit a list of prequalified project developers to PJM (referred to as Designation Entities) to construct a public policy project under the State Agreement Approach.[233]

231 An Immediate-Need Reliability Project is a reliability-based transmission enhancement or expansion: 1) with an in-service date of three years or less from the year PJM identified the existing or projected limitations on the transmission system that gave rise to the need for such enhancement or expansion; or 2) for which the PJM determines that an expedited designation is required to address existing and projected limitations on the transmission system due to immediacy of the reliability need in light of the projected time to complete the enhancement or expansion.

232 PJM, 2019 Regional Transmission Expansion Plan, February 20, 2020, at 15. FERC eliminated the FERC 715 TO criteria exclusion in an order on complaint EL 19-61.

233 PJM Answer, Docket No. EL20-10, at 24-25.

APPENDIX C: Interregional Projects

MISO and PJM

MISO and PJM complete interregional planning studies and share information through the MISO-PJM Interregional Planning Stakeholder Advisory Committee, where interregional planning studies are conducted under the PJM-MISO Coordinated System Plan ("CSP"). In both PJM and MISO, interregional projects must have a B/C Ratio of 1.25.

Article IX of the MISO-PJM Joint Operating Agreement ("JOA") governs the MISO-PJM interregional planning process. According to the MISO-PJM JOA, "The primary purpose of coordinated transmission planning and development of the CSP is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, enhance the competitiveness of electricity markets, or promote public policy."[234]

The MISO-PJM CSP identifies the following categories of interregional projects:

- **Cross-Border Baseline Reliability Project:** must meet the following requirements: (1) Joint RTO Planning Committee ("JRPC") agrees the project is needed to efficiently meet applicable reliability criteria; and (2) the project must be defined as a baseline reliability project per the MISO or PJM tariff. The costs of projects to relieve thermal constraints are allocated to each RTO based on the relative contribution of the combined load of each RTO to loading on the constrained facility that drives the need for the reliability upgrade. To allocate the costs of projects to relieve non-thermal constraints, the JRPC establishes an interface, which is composed of multiple transmission facilities, and costs are allocated according to each RTO's contribution to flows across that interface.[235]
- **Interregional Reliability Project**: a reliability project as defined in either the PJM or MISO tariff (or both) that more efficiently (or more cost-effectively) meets applicable reliability criteria than another "displaced" reliability project (or projects). The benefits of an Interregional Reliability Project are based upon the total avoided costs of regional transmission projects included in either a MISO or PJM regional plan that would be displaced by the Interregional Reliability Project. Costs of Interregional Reliability Projects are allocated according to the ratio of the present value of the estimated displaced reliability project cost in a given RTO to the total present value of the estimated costs of the displaced reliability projects in *both* RTOs.[236]
- **Interregional Market Efficiency Project**: a project that displaces one or more regional projects that address public policy in MISO or PJM by meeting the applicable public policy criteria more efficiently or cost-effectively than the displaced regional project(s).[237] The costs of an Interregional Public Policy Project are allocated to the RTOs according to the ratio of the present value of the estimated cost of each RTO's displaced public policy projects to the total of the present value of the estimated costs of

[234] MISO-PJM JOA, § 9.3.
[235] MISO-PJM JOA, § 9.4.2.2.1.
[236] MISO-PJM JOA, § 9.4.2.2.(i).
[237] MISO-PJM JOA, Article IX, § 9.4.4.1.4.

the displaced public policy projects in both RTOs. The MISO-PJM JOA states that MISO and PJM will work to ensure that cost estimates for displaced public policy projects are determined in a similar manner.[238]

- **Targeted Market Efficiency Project:** a project that meets the following criteria: 1) expected to substantially relieve historical market congestion; 2) estimated in-service date by the third-summer peak season from the year of project approval; 3) estimated installed cost less than $20 million; and 4) the expected congestion relief on the flowgate at issue over the next four years equals or exceeds the installed capital cost of the project.[239] The costs of Targeted Market Efficiency Projects are allocated to each RTO in proportion to the expected future congestion relief in each RTO.[240]

MISO and PJM completed a long-term Interregional Market Efficiency Project (IMEP) study in mid-2018. In the IMEP study, PJM, and MISO each developed regional market analyses and identified three congestion drivers along the PJM-MISO seam. PJM and MISO jointly solicited interregional market efficiency proposals through an open competitive window that closed on March 15, 2019. PJM and MISO received ten interregional proposals that addressed at least one of the three mutually identified congestion drivers. PJM and MISO calculated their respective regional benefits and determined the total project benefit. Based on the regional analysis and the total B/C cost ratio, one interregional project – the Bosserman-Trail Creek project - was recommended by both RTOs. The Bosserman-Trail Creek project will address persistent historical congestion projected to continue on the NIPSCO/AEP seam.[241]

In December 2019, PJM conditionally approved the Bosserman-Trail Creek project on the condition that the project also receive MISO Board approval. According to an August 18, 2020 JCM interregional update, MISO approved the interregional Bosserman-Trail Creek project in the MTEP20 in September 2020.[242] PJM's 2019 RTEP did not identify any drivers for potential interregional reliability projects and no significant drivers for other interregional studies were identified. Additionally, no other interregional studies were conducted in 2019 under the PJM-MISO CSP.[243]

SPP and MISO

The MISO-SPP interregional planning process is governed by Article IX of the MISO-SPP JOA. The Interregional Planning Stakeholder Advisory Committee (IPSAC) oversees the MISO-SPP interregional planning process. The MISO-SPP interregional planning process has yet to identify any interregional projects. MISO and SPP use their individual regional planning processes to determine the subset of needs along the SPP-MISO seam that will be studied in a MISO-SPP CSP.[244] MISO and SPP evaluate the need to conduct a CSP study on an annual basis.

The last CSP Study was issued in February 2020 and, SPP and MISO staff focused efforts on an economic analysis of targeted transmission needs along the seam identified in SPP's 2019 ITP Assessment and MISO's 2019 MTEP (MTEP19). Specifically, the MISO-SPP 2019 CSP study reviewed seven projects but none of them

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238 MISO-PJM JOA, § 9.4.4.2.3.
239 MISO-PJM JOA, Article IX, §9.4.4.1.5.
240 MISO-PJM JOA, § 9.4.4.2.5.
241 PJM, 2019 RTEP, at 56.
242 MISO Final MTEP20, October 2020, at 130. See also https://www.pjm.com/-/media/committees-groups/committees/mc/2020/20200914-webinar/20200914-item-03-interregional-coordination-update.ashx.
243 PJM, 2019 RTEP, at 56.
244 2019 MISO-SPP Coordinated System Plan Study Report, February 27, 2020, at 7. https://cdn.misoenergy.org/20200310%20MISO-SPP%20IPSAC%202019%20Coordinated%20System%20Plan%20Study%20Report433097.pdf.

met the criteria to qualify as a MISO-SPP interregional project.[245] MISO and SPP jointly recommended performing a CSP study in 2020 and work is underway on the 2020 MISO-SPP CSP study.[246]

In July 2019, the FERC approved changes to the MISO-SPP interregional planning process to: 1) eliminate use of a joint model and enable MISO and SPP to determine their own benefits; 2) consider additional benefits from potential interregional transmission projects, specifically APC and avoided reliability cost benefits; and 3) remove the $5 million minimum cost threshold for a project to be eligible as a transmission project.[247]

MISO and SPP independently evaluate the benefits of the transmission solutions proposed to address the needs identified at the flowgates MISO and SPP identify. SPP and MISO use each RTO's share of calculated APC benefits, as calculated using the methodologies used in MISO and SPP, respectively, to allocate the costs of economic interregional projects to each planning region. Solutions that primarily address reliability issues are allocated to MISO and SPP based on the sum of each RTO's avoided cost to address the reliability issue and the APC benefits.[248]

MISO-SPP interregional projects must meet all the following criteria:[249]

1. evaluated as part of a CSP study and recommended by the MISO-SPP JPC
2. approved by the SPP and MISO board of directors
3. the benefits to MISO and SPP must each represent 5% or greater of the total benefits identified for the combined MISO and SPP region
4. estimated in-service date is within 10 years of approval by the MISO and SPP boards of directors
5. project may interconnect to new or planned facilities in both the MISO and SPP regions or be wholly within the MISO or SPP region.

The benefit metrics MISO and SPP independently calculate to evaluate potential interregional projects that primarily address economic needs are based on APC,[250] with any reliability and public policy benefits, to the extent they exist, being added to the APC benefits.[251] For interregional projects that focus primarily on reliability issues, the reliability benefit is defined as the avoided cost of each RTO's regional project(s) that address the reliability issue.[252] Any economic benefits of reliability-focused projects are added to the avoided reliability cost metric.[253] If an interregional project primarily focuses on public policy needs and replaces a SPP or MISO (or both) project to address a public policy issue, the public policy benefit is the avoided cost of the displaced public policy projects.[254] Any economic benefits of public policy-focused projects are added to the public policy benefit metric.[255]

245 2019 MISO-SPP Coordinated System Plan Study Report, February 27, 2020.
246 Draft 2020 SPP-MISO Coordinated System Plan Scope for stakeholder comment, July 21, 2020, at 5, https://www.spp.org/Documents/62619/DRAFT%202020%20SPP-MISO%20CSP%20Scope%20for%20Stakeholder%20Comment.docx.
247 Midcontinent Independent System Operator, Inc. Southwest Power Pool, Inc., 168 FERC ¶ 61,018 (July 16, 2019) at P 5. The revisions also included process improvements.
248 SPP-MISO JOA, § 9.6.3.1.1.
249 SPP-MISO JOA § 9.6.3.1.
250 SPP-MISO JOA § 9.6.3.1.1.a.
251 SPP-MISO JOA § 9.6.3.1.1.a.iii-iv.
252 SPP-MISO JOA § 9.6.3.1.1.b.
253 SPP-MISO JOA § 9.6.3.1.1.b.ii.
254 SPP-MISO JOA § 9.6.3.1.1.c.
255 SPP-MISO JOA § 9.6.3.1.1.c.ii.

In September 2020, MISO and SPP announced a joint study that will "focus on solutions that the RTOs believe will offer benefits to both their interconnection customers and end-use consumers of RTO member companies."[256] The MISO press release announcing the study noted that no process currently exists where MISO and SPP can jointly evaluate and allocate the costs of transmission needs of loads and generation interconnection customers, "[w]hile MISO and SPP have an existing Joint Operating Agreement that allows them to work through reliability issues, existing processes do not include the simultaneous evaluation of benefits, or allocation of cost, to both load and interconnection customers."[257] As noted above, for the most part, generators pay all or most of the costs of system upgrades required for new generator interconnections. However, in conducting this joint study, MISO and SPP appear to recognize that upgrades identified in the generator interconnection process could also address the transmission needs of RTO loads, and thus benefit loads as well.

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256 MISO, MISO and SPP to conduct Joint Study Targeting Interconnection Challenges, September 14, 2020, https://www.misoenergy.org/about/media-center/miso-and-spp-to-conduct-joint-study-targeting-interconnection-challenges/

257 MISO, MISO and SPP to conduct Joint Study Targeting Interconnection Challenges, September 14, 2020, https://www.misoenergy.org/about/media-center/miso-and-spp-to-conduct-joint-study-targeting-interconnection-challenges/.