UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	))))	**RM21-17-000**

COMMENTS OF
THE AMERICAN COUNCIL ON RENEWABLE ENERGY

The American Council on Renewable Energy ("ACORE"), a national nonprofit organization dedicated to advancing the critical importance of renewable energy and to advocating for the market structures, policy changes and financial innovations designed to advance renewable energy deployment, hereby submits these comments in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") July 15, 2021 Advance Notice of Proposed Rulemaking, issued in the above-captioned proceeding, which seeks comments on potential reforms to the regional transmission planning and cost allocation and generator interconnection processes.[1]

The Commission's inquiry addresses many significant issues that, if left unresolved, will continue to prevent our nation from realizing renewable energy's full potential by, among other things, its economic and timely deployment. The current structure under which interconnection customers are being required to fund significant system expansions, and under participant funding models are essentially assumed to be the expansion's sole beneficiary, significantly contributes to the ongoing delays and gridlock in interconnection queues. It is also unjust and unreasonable and inconsistent with applicable precedent requiring that cost allocations be

[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (2021) ("ANOPR").

roughly commensurate with benefits, particularly given that, at the same time, regional transmission planning processes consistently fail to drive much-needed regional investment. To address these impediments, ACORE respectfully suggests that, at a minimum, the Commission do four things:

- Eliminate participant funding as soon as possible and consider replacing it with the crediting option provided under Order No. 2003 or with an allocation method that will be provably consistent with the Commission's cost allocation precedents and that does not undermine the goal to eliminate the further burdens posed by the fact that presently there can be little cost or schedule certainty for so long as interconnection customers remain hostage to iterative study processes;

- Fix the iterative interconnection study process do loop;

- Require transmission planners to incorporate and plan for future generation and load, including to regions with high levels of resource development potential; and

- Require that planners consider *simultaneously* the full benefits, costs and range of beneficiaries of proposed transmission, including future generation needs, and the economic, reliability, resilience, public policy and any other reasonably cognizable benefits.

The most immediate need is to eliminate participant funding, which, while once deemed to be just and reasonable, plainly no longer is, and to replace it either with the crediting mechanism provided under Order No. 2003[2] or with some other cost allocation that will be consistent with the Commission's cost allocation precedents and not require that interconnection customers be hostage to an iterative study process lasting years. But perhaps just as critical to address is the fact that the current rules virtually necessitate iterative studies,[3] further contributing both to the glut of seemingly already-studied projects waiting to make commitment

[2] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 (2003), *order on reh'g*, Order No. 2003–A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003–B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003–C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

[3] To be clear, ACORE is not referring to the basic study procedure, e.g., the system impact study and facilities study, but to the circumstance where these studies are seemingly perpetually revised and requests being restudied, sometimes even after an interconnection agreement has been executed.

decisions until yet more studies are concluded, and projects still waiting to be studied in the first place. As to all these projects (and oftentimes even after an Interconnection Agreement is tendered), the iterative study process guarantees there being little cost or schedule certainty for years – often up to 5 years – uncertainty that at a minimum significantly hinders economic and timely project financing and construction, if it doesn't cripple the project altogether. ACORE urges the Commission to move forward expeditiously and not delay action on the elimination of participant funding and on interconnection queue reform while the Commission proceeds to evaluate the planning elements of this rulemaking.

As significant is the transmission planning process which clearly has not produced much-needed transmission investment at necessary scale and/or in a timely fashion without rancor. The objective should not be controversial: these processes must not only address, but timely result in, the grid investments required to meet the challenges posed by a changing resource mix, growing and variable loads, and extreme weather events. For the reasons discussed below, ACORE believes that in order for the Commission to address the unjust and unreasonable cost allocations, and for renewable development to occur at the requisite scale and over the requisite time period, it is imperative that the Commission undertake systemic, national reforms. It must do more than establish just the objectives of the process. It should discontinue the practice of accommodating virtually all assertions of regional difference and provide regional exceptions only when those benefits would truly benefit customers and necessarily should be maintained.

Transmission construction is a nationwide issue, and just as it did with its national, jurisdiction-wide *pro forma* tariffs and procedures, the Commission must take on the particulars of "how it should be done," and then let stakeholders try to explain why any proposed deviation would equally well comport with the Commission's national obligations. No one who knows anything about what really happens when trying to interconnect a project or purchase transmission or obtain provider information, should question the fact that the Commission's *pro forma* tariffs rules have by far been the most important of the Commission's initiatives as to these subjects.

At a minimum, transmission planners must, first and foremost, comprehensively and *simultaneously* evaluate potential and existing transmission projects' full benefits, costs and capabilities, including their economic, reliability and public policy benefits, both extrinsic and intrinsic (such as climate and resiliency-related costs and benefits) against whatever alternatives there are to solving a given problem; and there needs to be a transparent and proactive process in place for identifying any given problem in the first instance that accounts for reasonable projections of future needs. Only then will the overall most beneficial and cost-effective projects be selected – whether transmission or non-transmission alternatives. Hence the "transmission" planning process must be informed by, and include, people who understand the products that compete with transmission and thereby reducing the risk that decisions to build (or not to build) significant transmission – with long lead times – will not be subjected to predictable and understandable litigation and/or political objections. Put simply, if the planning is not comprehensive, it will be comprehensively challenged no matter how flawless the engineering or pure the intentions.

Second, and more easily stated, the planning processes must be required proactively to plan not only for future load but also for future generation. Fortunately, as noted in the ANOPR, there are already some models in practice for doing just that.

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I. COMMUNICATIONS

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II. COMMENTS

A. Reforms are needed to the current interconnection cost allocation and transmission planning procedures.

The nation's current transmission planning, interconnection and cost allocation practices need to change. Under the policies set forth in Order No. 2003, while an interconnection customer is required initially to fund network upgrades, after the customer's generation project achieves commercial operation, the interconnection customer is entitled to reimbursement, either in the form of credits against charges for transmission service or in the form of a lump sum payment.[4] As the reimbursements are made, the cost of the network upgrades can be rolled into the transmission provider's transmission rates.[5]

Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs"), however, were given more flexibility to propose forms of participant funding;[6] and not surprisingly (given the voting dynamics of the stakeholder processes) each ISO/RTO has

[4] *See generally* Order No. 2003 at PP 693-703.

[5] Order No. 2003-A at P 657.

[6] Order No. 2003 at PP 699-700.

since implemented some form of participant funding. Under what came to be their models, interconnection customers do not receive monetary reimbursement, but instead are eligible to obtain tradable transmission rights that ostensibly equate to the value of the customer-funded upgrades that were then used by, and to the benefit of, all transmission customers.

However, since these policies have been implemented, the participant funding model has failed to provide the required opportunity for customers to receive valuable transmission rights, yet the benefits accrued from the customer-funded upgrades remain fully realized. The Commission must conclude that this policy violates the principles set forth in Order No. 2003, most significant of which is the principle requiring that cost allocations be roughly commensurate with benefits. Indeed, the real-world merits and implications of participant funding are so lopsided, so harmful to timely development and so altogether unfair that the Commission should immediately move forward to eliminate the participant funding option at the earliest feasible implementation date. The Commission should either replace it with the crediting option provided under Order No. 2003 or with an allocation method that will be provably consistent with the Commission's cost allocation precedents and that does not undermine the goal (discussed below) to eliminate the further burdens posed by the fact that presently there can be little cost or schedule certainty for so long as interconnection customers remain hostage to iterative study processes.

But participant funding models are unjust and unreasonable not simply because of the unfair (and oftentimes project-killing) costs that developers are forced to bear, but because of the deleterious effect that participant funding has on transmission planning, to the extreme detriment of developers *and* load in general. It is a fact that regional transmission planning processes have not adequately facilitated much-needed regional transmission planning and investment (and particularly the large regional and interregional transmission presently needed for resilience and to integrate anticipated future generation) and, as a result, the generator interconnection process which was designed to identify system upgrades for the narrow purpose of interconnecting a new generating facility, is increasingly used as the avenue for the development and funding of larger, regional facilities even though all of the costs of these projects are allocated almost entirely to the interconnecting generators precisely because these transmission projects were not already in a transmission plan. Plainly, this is not what the generator interconnection process was intended for, nor what even participant funding was intended for. Furthermore, the fact that generation projects in ISO/RTOs today are required to pay for all or nearly all of the costs of system upgrades or alternative non-transmission upgrades that benefit load as much if not more than the generators have been a significant factor in developers choosing to withdraw from the queue, which in turn is one reason for transmission providers having to perform iterative studies which likewise are actually crippling many interconnection queues.

Additionally, because the expanded grid is more and more the result of having to put together this patchwork of incremental transmission, no matter how large or small, emanating from participant funded interconnections, even if planners did have the incentive to plan for the most economic and efficient grid, they now have to deal with all these one-off transmission upgrades – upgrades that, had there been a comprehensive plan in the first place might never have been required because the plan entailed constructing different, more efficient and/or even more regionally beneficial facilities.

The long and short of it is that the current siloed, project by project and separate approach to transmission planning used in many regions has led to haphazard transmission development and has been skewed in some regions away from much-needed regional facilities in favor of local projects over which utilities can typically still exercise a first right of refusal. And in some regions, where transmission planning is separated into reliability planning and economic planning processes, these segregated processes often do not fully assess a project's true potential benefits and likewise makes it difficult to identify the overall best solutions for the whole system. For example, when, for instance, a potential economic project may only be evaluated based on economic benefits assessed under the applicable cost/benefit analysis, the project's potential reliability benefits would not be considered.

Holistic, forward-looking regional transmission planning is needed now more than ever, with the nation's generation fleet having changed significantly such that the majority of pending interconnection requests are for renewable resources which can be located in remote regions. Simply replacing old equipment is not going to be sufficient.

These issues are borne out in several recent industry reports that, together, paint a picture of a grid ossifying under the current framework and unprepared for changes in the nation's resource mix, demand patterns, and climate-driven imperatives. For example,

- A January 2021 report shows that, despite the potential benefits, regional transmission investment has not increased and in some regions even has declined over the past decade.[7]

- Another report from January 2021 found that during this same time, interconnection upgrade costs rose dramatically.[8]

- A March 2021 report describes how many RTO transmission planning processes focus on current system needs but are not designed to identify the transmission

[7] Americans For A Clean Energy Grid, "Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure," at 25 (Jan. 2021), available at: https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf ("ACEG Planning Report") (attached here as Exhibit 1).

[8] Americans For A Clean Energy Grid, "Disconnected: The Need for a New Generator Interconnection Policy," at 6 (Jan. 2021), available at https://acore.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf ("ACEG Report") (attached here as Exhibit 2).

expansions necessary to enable renewable energy development and causing generators to be routinely confronted with extremely high upgrade costs.[9]

- A July 2021 study of severe weather events that are becoming more common and more extreme shows that additional transmission investment could have significantly mitigated the impact of these events on the grid and the consequent harms.[10]

- A report from September 2021 shows that generator interconnection upgrades, the costs of which have mostly if not entirely been allocated to the interconnecting generator, can often provide substantial benefits to consumers.[11]

- And a report from just last week shows that, while a large share of new transmission investment is narrowly focused on generator interconnection upgrades and network reliability, what is really needed is a more proactive transmission planning process that considers, among other things, future generation and load and accounts for the full range of transmission benefits.[12]

The need for immediate reform is clear. Participant funding of generator interconnection upgrades is no longer just and reasonable and should be eliminated at the earliest feasible implementation date and replaced with the crediting option provided under Order No. 2003 or with some other allocation that will be provably consistent with the Commission's cost allocation precedents and that does not undermine the goal to eliminate the further burdens posed by the fact that there presently can be little cost or schedule certainty for so long as

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[9] Concentric Energy Advisors, "How Transmission Planning and Cost Allocation Processes Are Inhibiting Wind and Solar Development in SPP, MISO, and PJM," at vi (Mar. 2021), available at: https://acore.org/wp-content/uploads/2021/03/ACORE-Transmission-Planning-Flaws-in-SPP-MISO-and-PJM.pdf ("Concentric Report") (attached here as Exhibit 3).

[10] Grid Strategies LLC, "Transmission Makes the Power System Resilient to Extreme Weather," at 2-4 (July 2021), available at: https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf ("Resilience Report") (attached here as Exhibit 4).

[11] ICF Resources, LLC, "Just and Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits," at 29 (Sept. 9, 2021), available at: https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf ("ICF Report") (attached here as Exhibit 5).

[12] The Brattle Group and Grid Strategies, "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs," at iii-iv (Oct. 2021), available at: https://gridprogress.files.wordpress.com/2021/10/transmission-planning-for-the-21st-century-proven-practices-that-increase-value-and-reduce-costs-7.pdf ("Brattle-Grid Strategies Report") (attached here as Exhibit 6).

interconnection customers remain hostage to iterative study processes. The Commission should also direct more long-term systemic reforms to the transmission planning process to address these underlying issues by more holistically evaluating potential transmission investments and proactively planning for not just future load but also future generation.

B. Participant funding for interconnection-related network upgrades is unjust and unreasonable, and should be eliminated (IV.B.3)

The Commission sought comment on whether it is appropriate to eliminate or reduce participant funding for interconnection-related network upgrades in RTOs/ISOs.[13] ACORE strongly supports eliminating participant funding of 100% of the costs of generator interconnection network upgrades at the earliest feasible implementation date.

1. The basic principles underlying the Commission's long-standing cost allocation policies remain valid

The Commission has never deviated from its position that the transmission grid operates as a cohesive network that benefits all users.

> The Commission has long held that an integrated transmission grid is a cohesive network moving energy in bulk. Because the grid operates as a single piece of equipment, the Commission has consistently priced transmission service based on the cost of the grid as a whole. The Commission has rejected the direct cost assignment of grid facilities even if the grid facilities would not be installed but for a particular customer's service. The Commission has reasoned that the, even if a customer can be said to have caused the addition of a grid facility, the addition represents a *system* expansion used by and benefitting *all* users due to the integrated nature of the grid.[14]

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[13] ANOPR at P 119.

[14] *Public Service Company of Colorado* 59 FERC ¶ 61,311 (1992), *order on reh'g*, 62 FERC ¶ 61,013 at 61,061 (1993) ("*PSCO*") (emphasis in original; footnotes omitted).

In Order No. 2003, the Commission reaffirmed its holdings in *PSCO*, and rejected arguments that an interconnection customer should be assigned the costs of network upgrades that were constructed to accommodate its interconnection.[15] Instead, the cost of such network upgrades is to be recovered in the transmission provider's transmission rates from all users of the grid.[16]

The Commission did, however, adopt an approach which required (1) the interconnection customer to initially fund all costs related to its interconnection, including network upgrades that would not have been required "but for" the interconnection request and (2) the transmission provider to reimburse the interconnection customer after its project reached commercial operation.[17] The reimbursement could be in the form of transmission credits (credits against the charges assessed for transmission services that were associated with the generation facility and which were assignable, *e.g*., assignable to a transmission customer that was an offtaker),[18] or reimbursed through such other mutually agreeable reimbursement method that had to ensure reimbursement of the full cost, with interest, within 20 years.[19] The Commission also allowed transmission providers to elect to "self-fund" meaning that the transmission provider could elect to reimburse the interconnection customer immediately, in which case the transmission provider could roll the costs of the upgrades into its transmission rates immediately and, as a result, avoid paying the interconnection customer interest for periods prior to reimbursement and immediately

[15] Order No. 2003-A at 585.

[16] Network upgrades are defined as upgrades that are located at or beyond the point of interconnection. ACORE is not proposing any change in the Commission's policy that the interconnection customer be assigned the cost of any facilities that are located behind the point of interconnection, i.e., Transmission Owner's Interconnection Facilities.

[17] *See generally* Order No. 2003 at PP 693-703.

[18] Order No. 2003 at P 734.

[19] *See* Section 11.4 of the *pro forma* Large Generator Interconnection Agreement.

start to earn a return on the investment.[20] The Commission's crediting policy ensured that the beneficiaries of the network upgrades, *i.e.*, users of the transmission grid – will pay for those facilities.

2. **<u>The expectation that participant funding would provide value in return for upgrade funding has never been realized</u>**

In Order No. 2003, the Commission also introduced an option for participant funding which would not provide for the reimbursement of network upgrade costs to the interconnection customer. The Commission allowed an independent transmission provider, such as an ISO or RTO, to require the interconnection customer to fund all network upgrades, without receiving a cash reimbursement, and instead receive in return valuable rights. In other words, while not a perfect match for cost reimbursement, it was expected to provide an opportunity for the interconnection customer to realize a financial value, either directly through a revenue stream while utilizing these transmission rights or monetizing it in trades with other parties.

The Commission's expectations that participant funding would provide a reasonable financial value has been elusive if not entirely ephemeral. Congestion revenue rights and similar long-term financial transmission rights have generally proven to be vastly inadequate, in terms of their availability, their predictability and their value, to compensate generators for the significant investment in network upgrades, and to recognize the system benefits thereby created. These are not reasonable substitutes for cost reimbursement. Indeed, one head scratcher is the fact that instruments that provide congestion hedges have no value to the generator when the upgrade removes the congestion or when the upgrade simply replaces aging equipment with new

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[20] *See* Order No. 2003 at P 720. As the Commission has noted, the self-funding option under Order No. 2003 is different from the approach labeled "self-funding" in MISO that is an option provided to transmission providers under the participant funding method currently in place in MISO. See *Otter Tail Power Co., et al.*, 153 FERC ¶ 61,352 at P 30 (2015).

equipment. And they are often made available only if transmission customers exercise their priorities to these instruments in return for their paying for firm transmission service.[21] Moreover, a congestion hedge can serve as a benefit, or credit, to the holder if it pertains to an energy flow in the same direction as the congested flow, but will serve as a liability, *or charge*, to the holder if it constitutes a counter flow (*i.e*., represents a flow of energy in the opposite direction as the congested flow). In any event, ACORE is unaware of any occasions when an interconnection customer has realized a measurable value in return for participant funding.[22]

Now, more than 15 years after the Commission expressed its expectation that participant funding would provide value to interconnection customers funding network upgrades, new generation projects are often asked to pay for significant transmission expansion projects without receiving any measurable benefit in return.[23] Indeed, an ICF Report prepared for ACORE found, in Midcontinent Independent System Operator, Inc. ("MISO") and Southwest Power Pool, Inc. ("SPP") (where there is currently over 150 GW of active solar, wind and hybrid resources stuck in interconnection queues across both markets),[24] that even using very conservative assumptions,

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[21] There is not an unlimited supply of congestion hedges provided through firm transmission rights and their ilk. The quantity and their locational value are determined to be limited to those that are consistent with the load volumes and locations likely to involve congestion.

[22] The ANOPR cites language in Order No. 2003 that described PJM's claim that Capacity Interconnection Rights ("CIRs") would constitute a valuable tradeable transmission right received in return for participant funding. ANOPR at P 108. This label is not correct. CIRs are simply the amount of unit capacity that is permitted to participate in the capacity market. However, participant funding in PJM is not limited to situations to situations where the customer seeks CIRs, and they are often provided only for a portion of the capacity value, particularly with respect to renewable projects where capacity eligible for participation in the capacity market reflected derated amounts. Finally, there is no way to monetize the value of CIR by trading it immediately to a third party. A CIR can only be transferred to a new interconnection customer that is constructing a different generation project and the existing project is most likely going out of business and where the new project is still responsible to participant fund its own network upgrade costs.

[23] Order No. 2003 at P 695.

[24] ICF Report at 2. Currently solar, wind and hybrid projects represent 92% of active requests in the MISO queue and up to 95% in the SPP queue. *Id.*

in MISO and SPP, of the upgrades that were funded entirely by the interconnection customer, fully two-thirds of them created system-wide benefits -- a result clearly at odds with "beneficiary pays" cost allocation principles.[25] Renewable generation interconnection requests have risen exponentially in both MISO and SPP as the cost of wind and solar energy has continued to decline and states and corporate buyers seek to meet their renewable energy objectives.[26] For example, in its most recent Definitive Interconnection System Impact Study ("DISIS"), SPP identified the need for transmission expansions costing more than $4.6 billion in order to interconnect 10.4 GW of generation.[27] If developed and funded by interconnection customers, this will increase the cost of such development by approximately $448/kW.[28] Similarly in its most recent Definitive Planning Phase ("DPP") study, MISO identified the need for nearly $2.5 billion of upgrades to interconnect 9.2 GW of generation in MISO South which translates to approximately $271/kW.[29]

Because the promise of a comparable reimbursement scheme never appeared, participant funding today simply means that the interconnection customer foots the entire cost for upgrades and system expansions that benefit all users of the network and violates the Commission's long-standing prohibition, as set forth in *PSCO* and reinforced in Order No. 2003, against the direct assignment of a network expansion even where a customer may have been the cause for such expansion. Moreover, in the absence of any expected quid pro quo of a valuable right,

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[25] *Id.* at 38. There is a nominal 10% reimbursement for interconnection customers in MISO funding upgrades with a voltage of 345 kV and above which are determined by MISO to be a Multi-Value project.

[26] *Id* at 16.

[27] *Id.* at 2.

[28] *Id.*

[29] *Id.*

participant funding is directly at odds with the Commission's obligation to ensure that costs allocations be roughly commensurate with the benefits received.[30] Indeed, no one ever has shown with evidence (as opposed to theory) that a transmission rights regime achieves this end in practice.

Participant funding and the direct assignment of system expansion costs without reimbursement through the interconnection process has become increasingly untenable, not simply because it has led to unfair cost allocations, but in light of its impact on the efficient processing of interconnection requests and the efficient development of today's generation mix. Participant funding contributes to delays and gridlock in interconnection queues by incentivizing holding on to speculative queue positions that "test" the injection point's cost responsibility, followed by late stage withdrawal, and thereby ensuring the need for restudies that in turn results in significant delays for both generators remaining in the queue and even for those already studied but now subjected to the restudies. And all this, in turn, results in higher power purchase agreement ("PPA") prices, which in turn results in increases in the cost of delivered power for consumers, or even more perversely, it may result in the interconnection customer eating the cost and adversely affecting the expected economics of the PPA, when it cannot ascertain at the time a PPA is signed what the actual cost responsibility will be.

Americans for a Clean Energy Grid ("ACEG") recently reported on the significant and adverse impact that participant funding has had on the nation's grid.[31] As we noted above, the most significant driver for the multiple rounds of restudies is the withdrawal of projects due to

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[30] *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) ("*ICC*") (cost allocations must be "at least roughly commensurate" with the benefits); *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1263 (D.C. Cir. 2018) ("the cost causation principle prevents regionally beneficial projects from being arbitrarily excluded from cost sharing—a necessary corollary to ensuring that the costs of such projects are allocated commensurate with their benefits.") ("*Old Dominion*").

[31] *See generally* ACEG Report.

uncertainty about their cost responsibility. As detailed in that report, the current system for planning and paying for expansion of the transmission grid is so unworkable and inefficient, it is creating a huge backlog of unbuilt generation energy projects. At the end of 2019, 734 GW of proposed generation were waiting in interconnection queues nationwide.[32] This backlog is needlessly increasing consumer electricity prices by delaying the construction of more efficient and less costly new projects relative to existing electricity production. And because many of these projects are located in remote rural areas, this backlog is also harming rural economic development and job creation.[33] And the paralysis of the interconnection queues risks the ability of states, utilities and large consumers to scale up their renewable energy use and thereby reduce pollution and avoid paying its intrinsic costs.[34] The risk from the uncertainty that is now the hallmark of today's interconnection processes significantly increases the cost of capital for generation developers which, again, increases the price of energy to customers.

Furthermore, as also detailed in the ACEG Report, the process under which costs are identified and allocated, has been a major factor contributing to projects withdrawing from interconnection queues. Indeed, the ACEG Report states that all but 250 MW of MISO's West 2017 Study Group which started with 5000 MW being studied, had withdrawn, some of which had power purchase agreements.[35] When projects are withdrawn, it triggers a need to restudy the system impacts on the generation remaining in the queue, exacerbating delays in the generator interconnection process. Over the period from 2016 through 2020 more than 30% of the

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[32] *Id.* at 4.

[33] *Id.*.

[34] *Id.*

[35] *Id.* at 17.

proposed wind, storage and hybrid projects that had reached advanced stages in the MISO queue were withdrawn, equivalent to nearly 35 GW of clean energy -- costing 72,000 jobs.[36]

Until a few years ago, the interconnection charges for new renewable resources would comprise under 10% of the total project cost for most projects. In recent years, due to the lack of sufficient large-scale transmission build and the reliance on interconnection customers to fund large grid expansions, these costs have dramatically risen and interconnection charges now can comprise as much as 50 to 100% of the generation project costs.[37] Customers today are facing costs that are many tens of millions of dollars to construct facilities that will, in fact, form part of regional backbone transmission, or the replacement of an aging backbone transmission element, that should have been more efficiently identified and addressed in a regional plan had the natural expectation of new generation been given due consideration. The system has reached a breaking point recently as virtually no transmission capacity remains available. Indeed, in most regions, new network capacity is needed for almost all of the projects in the queues.

Relying on the interconnection process to identify needed transmission leads only to a piecemeal approach to augmenting the grid; and requiring interconnection customers to pay the tab for all these upgrades leads only to inefficiently sized upgrades, and increased prices to consumers. The incremental reforms at the RTO-level over the past decade have served only to treat the symptoms of this fundamental issue – the lack of alignment between regional planning processes and the interconnection process.

From its inception and over the more than 15 years since participant funding was authorized, this model has failed to ensure that customers would be reimbursed through the

[36] Concentric Report at vii.

[37] ACEG Report at 6.

receipt of valuable transmission rights for the investments they made with cold hard cash. It is also inconsistent with the Commission's precedent and principles of cost causation. The Commission has rejected the direct cost assignment of grid facilities even if the grid facilities would not be installed but for a particular customer's service.[38] And, similarly, when the Commission categorically prohibited regional cost allocation for high voltage transmission facilities that produced significant regional benefits, on the grounds that the projects reflected the planning criteria of individual utilities, the D.C. Circuit reversed and found that this "produces a severe misallocation of the costs of such project."[39] Indeed, the courts have been clear that cost allocations must be "at least roughly commensurate" with the benefits.[40] Thus, the direct assignment of system expansion costs to interconnection customers without reimbursement under the current participant funding structure is unjust and unreasonable, inconsistent with cost causation principles, and continues to contribute to the ongoing delays and gridlock in interconnection queues.

Accordingly, the Commission should immediately move forward in a proceeding under Section 206 and/or in one or more Show Cause proceedings to eliminate the participant funding option and replace it with the crediting option provided under Order No. 2003 or with some other allocation that will be provably consistent with the Commission's cost allocation precedents and that does not undermine the goal to eliminate the further burdens posed by the fact that there presently can be little cost or schedule certainty for so long as interconnection customers remain hostage to iterative study processes.

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[38] *PSCO* 62 FERC ¶ 61,013 at 61,061.

[39] *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1261 (D.C. Cir. 2018).

[40] *ICC*, 576 F.3d at 477.

3. **<u>Going forward without participant funding</u>**

While ACORE expects that FERC will continue to evaluate cost allocation between generators and load that are consistent with FERC's beneficiary pays principles and preserves the signal for generators to site their resources efficiently, ACORE is concerned that simply eliminating participant funding and returning to Order No. 2003 crediting approach for network upgrades currently used in non-ISO/RTO regions, will still not, by itself, resolve the fact that cost allocation rules are themselves drivers for delay and the need for interconnection restudies.

A return to the Order No. 2003 crediting policy will not be sufficient to eliminate the queue backlogs and promote efficient and timely development. The Commission's "but for" policy requires the Transmission Provider to assign the cost of an upgrade to the interconnection request that first causes the need for upgrade. Even where these costs may be allocated to clusters, there is one group of customers that will be on the hook to fund the upgrade, with the understanding that, if the others in that cluster drop out, its share moves closer and closer to 100% of a cost, and even that cost will remain uncertain if additional rounds of restudies are required. The fact that the customer may receive credits as much as 20 years later does not diminish the need for certainly early in the interconnection process of what the funding cost will be. ISOs, RTOs and Transmission Providers have attempted queue reforms intended to reduce the restudy delay cycles, but, while well-meaning, today's problems in the aggregate are no less than they were before such reforms were undertaken.

The "but for" policy made sense 20 years ago when there were far fewer interconnection requests and upgrades typically would be limited to constructing a new substation or to reconducting a nearby transmission line to resolve local issues. But that is no longer the case. It is important that any new allocation method provide reasonable certainty early in the process as to the customer's responsibility for its interconnection related costs.

To this end, ACORE suggests that the Commission replace the traditional "but for" analysis that attempts to identify the specific upgrades that will be the cost responsibility of the interconnection customer in favor of a "fair share" policy which continues to reflect some metric tied to the cost of interconnection on the transmission system as a whole or in a zone. The cost responsibility would be in the form of a fee, perhaps a fee that reflects some percentage of average historical or projected interconnection costs for all interconnection projects over time, which fee likely would be reduced if transmission planning were more robust. The fee could vary based on the size of the project, although it is not necessarily the case that the costs of upgrades for small projects (or the benefits that accrue therefrom) are less than the costs of upgrades for larger projects. But what is important is that the fee be definitively identified early in the process and not subject to further change (possibly within a capped amount, and only after exceeding that amount by a certain percentage) during the interconnection process or after the interconnection agreement is executed. This approach could also provide for reimbursement for all or a portion of the upfront fee to further ensure that all transmission users – the beneficiaries of system expansions – pay for the costs of those upgrades. However, an upfront fee (possibly per MW and/or determined on a zonal basis) would ensure that interconnection customers have some skin in the game before moving forward on an interconnection request. Obviously, some customers could end up paying fees that are higher or lower than the costs that they would have incurred under a "but for" analysis, but a cost allocation process based on an evaluation of average costs fairly could reflect the fact that the entire system in fact does benefit from the addition of new transmission, particularly when the great majority of that transmission is being built to allow renewable energy projects to be constructed in furtherance of both state and federal interests in facilitating such development (precisely because the presence of more renewable in fact is deemed to benefit ratepayers). It seems entirely illogical and counterproductive for a utility or state that wishes to increase renewable power development not to recognize the benefits of doing so when assessing how to allocate the costs of the transmission without which such development could not occur. Put simply, this potential approach would reflect a fair share allocation to both interconnection customers and the load to be served upon construction of that transmission.

To be clear, cost uncertainty is the primary reason that interconnection queues become clogged and project schedules are delayed for long periods of time, if not rendered irrelevant because the project ended up withdrawing from the queue due to the impossibility of knowing if the project will remain economic and financeable. Interconnection customers cannot make informed business decisions until the final cost is known, yet in most areas of the country where projects would be economic and are needed, the final cost becomes almost perpetually unknowable when subject to each and every restudy that must be performed as projects drop out of the interconnection queues. Conversely, a known fee subject to reasonable caps would mean these restudies could occur without the projects remaining in development limbo – which alone should be viewed as a significant benefit if as a result, the much-desired renewable energy is more quickly constructed and the interminable disputes emanating from project uncertainty to be significantly reduced. For this reason, it is essential that any cost allocation method provide for a defined fee early in the interconnection study stage that will not be revised at a later date.

4. **Affected Systems must be addressed at the same time**

Adopting new cost allocation approaches that will remedy the factors causing the backlogged interconnection queues will not be effective unless the Commission considers the multiple restudies and consequent delays and unnecessary withdrawals routinely associated with Affected System evaluation. When Order No. 2003 was issued, an Affected System was generally expected to be a neighboring system. Today, that is not the case. Instead, Eastern RTOs such as PJM make Affected Systems claims involving projects located as far away as South Dakota.[41] And interconnection customers are expected to resolve long-standing ISO/RTO seams issues with costs sometimes reaching hundreds of millions of dollars.[42] And then, if that's not bad enough, adding to the unfairness, the ISO/RTOs cannot claim to offer valuable rights to the interconnection customer in return for paying for whatever upgrades were identified in these studies.

While the dysfunction of Affected Systems cannot be resolved solely through cost allocation reform and should be an important consideration in new planning models, efforts to improve the cost certainty for customers with respect to the interconnecting ISO/RTO will fail if customers must still deal with the continuing uncertainty associated with potentially numbing Affected Systems obligations.

C. <u>Regional transmission planning processes should more comprehensively evaluate potential benefits (IV.B)</u>

The Commission sought comment on whether a portfolio approach to regional transmission planning that considers a group of transmission facilities that collectively provide multiple benefits, such as reliability, economic, and Public Policy Requirements benefits, may be more efficient and cost-effective than a process that focuses only on individual transmission facilities or individual benefits.[43] ACORE strongly supports reforms to both RTO and non-RTO planning processes that more comprehensively consider a portfolio's potential benefits and

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[41] "Comments of Invenergy Wind Development North America LLC, Invenergy Solar Development North America LLC, Invenergy Thermal Development LLC, and Invenergy Storage Development LLC," at 8, Docket Nos. AD18-8-000, EL18-26-000 (May 22, 2018).

[42] *Id.* at 9.

[43] ANOPR at P 91.

which could assist with identifying the most overall beneficial transmission projects and facilitate their development. This also would have the salutary effect of not having individual interconnection customers pay for, and be subject to the time to construct upgrades that should have been included in a transmission plan in the first place. Indeed, if they were, perhaps the greatest impact would come from some of these planned upgrades already having been constructed, or in process, *before* the interconnection customer even has filed an interconnection request and well before the need to commence their construction would first be identified in a System Impact or similar interconnection study. Imagine how much more quickly new generation could start to be injected into the grid if much of the infrastructure required to do so already was in the process of being constructed. And this acceleration would be another significant benefit of having eliminated participant funding and the uncertainty associated with a developer's having to wait for any more or "final" restudies before being able to decide to go forward.

The Commission issued Order No. 1000 nearly a decade ago in an effort to promote regional transmission planning. While Order No. 1000 was a good first step, it has not in practice produced results, at least not of any consequence relative to the Commission's overall objectives or to enhance the development of new generation. The Commission's general direction was that utilities participate in a regional planning process "that evaluates transmission alternatives at the regional level that may resolve the transmission planning region's needs more efficiently and cost-effectively than alternatives identified by individual public utility transmission providers in their local transmission planning processes."[44] But the Order, although

[44] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 at P 6 (2011), *order on reh'g and clarification*, Order No. 1000-A, 139 FERC ¶ 61,132 at PP

at its core intended to facilitate a regional transmission plan,[45] has, instead, resulted in a plethora of siloed planning processes often skewed toward smaller local projects outside of the regional planning process.

Meanwhile, interconnection customers are being saddled with ever increasing network upgrade costs through the generator interconnection process, as they are required to fund major system upgrades with benefits that likely extend far beyond simply interconnecting the generator. The ACEG Report shows how these interconnection upgrade costs have risen dramatically, with some MISO interconnection customers recently being assigned upgrade costs of nearly $1,000/kW.[46] These upgrade cost assignments can easily render a project unviable, leading to the upgrade not being constructed, and, by assuming that the interconnecting generator is essentially the sole beneficiary, failing to account for the full scope of benefits that would have resulted from that upgrade. As stated in the ACEG Report, "[l]arge new transmission additions create broad-based regional benefits by providing customers with more affordable and reliable power, so charging only interconnecting generators for this equipment requires them to fund infrastructure that benefits others."[47] This needs to change.

As mentioned above, one reason today's transmission planning processes are not meeting transmission development needs is that in some regions transmission planning separates reliability planning and economic planning, and the merits of a project under evaluation as either a reliability or economic project are dependent upon different criteria and assessed on that basis

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428-30, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom., S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[45] *Id*. at P 11.

[46] ACEG Report at 13-16.

[47] *Id.* at 16.

rather than *all* of the project's potential benefits, which makes it difficult to identify the overall best solutions for the whole system (and requiring that generator interconnection is treated as yet another separate process).[48] A single transmission project very well might provide varying degrees of reliability benefits, certain economic benefits, as well as potential public policy benefits and, for instance, to the extent a potential economic project may provide certain economic benefits assessed under the applicable cost/benefit analysis, these metrics may not fully capture the project's potential reliability benefits and, therefore, would not fully account for its true benefits.[49] This siloed, independent approach has led to haphazard transmission planning and investments. Under the circumstances, it could not be otherwise.

Transmission planning should entail a comprehensive evaluation of all reasonably potential projects through a single process considering each project's portfolio of potential benefits in a more holistic manner. The Brattle-Grid Strategies Report describes MISO's Multi-Value Process ("MVP") as an example of a current planning process where multiple benefits are considered, including: "(1) congestion and fuel cost savings; (2) reduced costs of operating reserves; (3) reduced planning reserve margin requirements; (4) deferred generation investment needs due to reduced on-peak transmission losses; (5) reduced renewable investment costs to meet public policy goals; and (6) reduced other future transmission investments."[50] But additional potential benefits, such as climate-related improvements from renewable energy

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[48] Concentric Report at 9. For example, the Concentric Report describes how most RTOs rely primarily on the adjusted production cost savings metric, which estimates short-term cost savings under baseline conditions, to evaluate project benefits under cost to benefit analyses but this accounts for only a portion of potential benefits, neglecting others such as reduction of transmission losses, and public policy benefits of renewable generation, which could lead to the rejection of otherwise beneficial projects. *Id.* at 24-29.

[49] Brattle-Grid Strategies Report at 31 ("If a project is driven by reliability needs, the broader economic and public policy benefits provided by the project are usually not quantified and considered. If a project is categorized as an economic or public policy project, but simultaneously provides reliability benefits without addressing a specific reliability violation, that reliability benefit usually is not considered either.").

[50] *Id.* at 54-55.

projects, resiliency and enhancements to the system's ability to withstand today's extreme weather also should be considered, as well as any benefit made known to the planners by the project's sponsors and reasonably cognizable. For example, the Resilience Report found that during the February 2021 Winter Storm Uri, each additional GW of transmission between ERCOT and the Southeast could have saved nearly $1 billion; and in parts of the Central U.S. consumers could have avoided power outages and saved over $100 million for each GW of transmission ties to power systems in the East.[51]

This type of a more comprehensive planning process would allow projects to be more efficiently evaluated and for the resulting transmission investments to be optimized. Unfortunately, though, the Brattle-Grid Strategies Report shows that MISO has not approved a project through its MVP process since 2011 and the vast majority of its anticipated current transmission investments are expected to be in local reliability projects – $2.8 billion approved for local reliability projects, as compared to $755 million for regional reliability projects and zero for MVPs.[52]

This trend toward local projects, *i.e.*, smaller transmission investments that do not typically expand regional grid capacity and, unlike regional projects generally remain subject to the utility's right of first refusal,[53] has increasingly been the focus of utility planning processes.[54] But, while these local projects may be preferred by utilities, they are clearly insufficient to address the larger needs of the transmission system. RTOs, ISOs and Transmission Owners should be required to assess smaller local projects and to evaluate whether one or more larger

[51] Resilience Report at 2.

[52] Brattle-Grid Strategies Report at 3 (Table 1).

[53] Order No. 1000 at PP 313, 318-19.

[54] ACEG Planning Report at 70-72; Concentric Report at 9-10.

regional projects would be more beneficial and cost-effective. While there may be a role for local projects, this disproportionate focus on these smaller projects amounts to a series of temporary fixes and should not be permitted to effectively crowd out investment in larger and potentially more efficient regional investments.

The inputs and models used in this process should also be transparent and subject to the review and stakeholder approval during the planning process. They should incorporate reasonable assumptions and expectations, including future potential generation, and when applicable the role of grid-enhancing technologies in the transmission planning process. For instance, to the extent it is not already happening, projects approved through utilities' integrated resource plans can often reasonably be expected to be constructed and should also be accounted for in regional planning regardless of whether the project has an executed interconnection agreement. Similarly, a merchant transmission project that is sufficiently advanced and being constructed should be incorporated in planning models, regardless of whether the merchant facilities are themselves cost allocated through that process.

D. Regional transmission planning should consider future generation (IV.A)

The Commission sought comment on whether reforms are needed regarding how the regional transmission planning and cost allocation processes model future scenarios to ensure that those scenarios incorporate sufficiently long-term and comprehensive forecasts of future transmission needs.[55] It asked whether transmission planning should include a process to identify geographic zones that have the potential for the development of large amounts of renewable generation and plan transmission to facilitate the integration of renewable resources in

[55] ANOPR at P 46.

those zones.[56] And it sought comment on whether reforms are needed to improve the coordination between the regional transmission planning and cost allocation and generator interconnection processes.[57]

ACORE strongly supports reforms to require that transmission planning consider both future load as well as future generation. The transmission planning and generator interconnection processes currently operate on different timelines, assess different time horizons and generally serve different purposes and while it may be worth exploring ways to better align the two processes, at least under the current construct, they should remain largely separate. However, as described in the ANOPR, several regional planning efforts have already been performed to proactively identify and plan for areas with high potential for renewable generation and these could be models for other regions to follow. Those efforts were exceptions to the rule, and the Brattle-Grid Strategies Report shows that of all the recently approved plans by the 11 Planning Authorities, only one of them reflected a multi-benefit analysis and the vast majority did not use any of the practices recommended in that report (proactive, multi-value, scenario-based, portfolio-based and interregional joint planning).[58]

Many existing transmission facilities were constructed several decades ago, and with these facilities now aging, there is a need for expansion of regional and inter-regional transmission infrastructure.[59] The nation's generation fleet has also significantly changed in recent years, with the majority of pending interconnection requests for renewable resources

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[56] ANOPR at P 54.

[57] *Id.* at P 65.

[58] Brattle-Grid Strategies Report at 15 (Table 2).

[59] ACEG Planning Report at 15, 18-19.

which can be located in remote regions, and simply replacing old equipment is not sufficient for future needs.[60]

Planning processes should more proactively consider future generation in addition to future load and use a 20-year planning horizon, that could be updated biannually, which aligns with when many state clean energy policy developments and has already been used in some regions.[61] These current processes generally consider new generation only once an interconnection agreement has been executed.[62] But this not only chronically underestimates future renewable generation, but the timing mismatch – whereby new transmission construction can require significant lead time, yet interconnection customers are often expected to achieve commercial operation on shorter timelines or risk termination of their interconnection agreements – is another hindrance to renewable generation development.[63]

The planning process needs to be more proactive about anticipating future generation and one way to do this is for transmission planning processes to identify geographic areas where a demand for interconnection is anticipated because of favorable conditions and that need could be built into the transmission planning process. This could be far more efficient than the transmission owner separately studying and assigning a series of incremental upgrades to different generators and could also result in significant cost savings. For instance, the Brattle-Grid Strategies Report states that a study of MISO interconnection showed that a more proactive transmission planning approach could facilitate interconnection of over 17,000 MW of new wind

[60] *Id.* at 24.

[61] *See e.g.*, Concentric Report at B1 (noting MISO long-term planning horizons of 11-20 years).

[62] *Id.* at vii.

[63] *Id.* at vii-viii.

generation capacity at a cost of approximately $149/kW, as compared to the $750/kW in upgrade costs then being assigned in the MISO interconnection queue.[64]

The Commission approved an early model of this when proposed by California Independent System Operator Corporation ("CAISO"), under which CAISO would develop facilities interconnecting remote areas in anticipation of generation development and the associated costs would be initially rolled into transmission rates, but as generators subscribed to capacity on the facilities, they would assume the associated costs.[65] The Commission recognized that "[t]he difficulties faced by generation developers seeking to interconnect location-constrained resources are real, are distinguishable from the circumstances faced by other generation developers, and such impediments can thwart the efficient development of needed infrastructure."[66] These impediments are not limited to the CAISO footprint and similar models could help facilitate renewable generation development in other regions.

However, while there may be constructs like the CAISO example described above where it makes sense for interconnection customers to fund discrete portions of larger projects, at least under the current construct, the transmission planning and generator interconnection processes are sufficiently distinct, and serving different goals, that they should remain largely separate processes. Generators should not, as a general matter, be put in a position of funding transmission expansion that is planned primarily for the benefit of load.

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[64] Brattle-Grid Strategies Report at 7.

[65] *California Independent System Operator Corp.*, 119 FERC ¶ 61,061 (2007); *see also* ANOPR at P 56.

[66] *California Independent System Operator Corp.*, 119 FERC ¶ 61,061 at P 2 (2007); *see also* "Decision for Conditional Approval of the Highwind Location Constrained Resource Interconnection Facility (LCRIF) Project," memorandum to ISO Board of Governors from Laura Manz (May 8, 2009), available at: http://www.caiso.com/Documents/090518Decision_ConditionalApproval-HighwindLocationConstrainedResourceInterconnectionFacilityProject-Memo.pdf.

There are many reasons why this could be problematic under the current structures. One factor is the different time horizons. The generator interconnection process and transmission planning processes are on separate tracks and timelines, where "the meaningful information that the generator interconnection process could provide is seldom available in the time frame needed for the transmission planning process."[67] Another factor is the potential that generators could be allocated costs for facilities and upgrades that are planned primarily for the benefit of load, *e.g.*, new transmission that is being built to benefit load and reduce ratepayer costs through, among other things, increasing market competition or deferring generation capacity investments, which would be inappropriate under a beneficiary pays principle.

E. <u>Interregional planning must be better coordinated (IV.A)</u>

The Commission also sought comment on whether reforms are needed to the current interregional transmission coordination process.[68] ACORE supports reforms to the current interregional coordination processes. As described in the ACEG Planning Report, to date, no significant interregional projects have been approved.[69] One of the primarily reasons for this is the so-called "triple hurdle," where interregional projects must not only be selected through the interregional process, but they must also be approved by the respective regions which may themselves evaluate the projects under different benefit metrics.[70] At a minimum, the Commission should require that neighboring regions use compatible benefits metrics and study approaches in evaluating interregional projects, and these metrics should capture all potential project benefits.

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[67] Concentric Report at 10.

[68] ANOPR at PP 62-64.

[69] ACEG Planning Report at 55-56.

[70] *Id.*

F. FERC should move forward with separate rulemakings for planning and interconnection cost allocation.

Though planning reform can serve as a long-term fix to interconnection backlogs, participant funding must be eliminated as soon as possible. As detailed above, the aspect of participant funding that was relied upon to ensure that it was just and reasonable – access to valuable, tradable transmission rights – has proven not to be true. And it is the major driver for the dysfunction that ISO/RTO interconnection processes are all evidencing. As such, the Commission can no longer conclude that participant funding is just and reasonable. The Commission should move forward with a separate rulemaking to eliminate participant funding and adopt new cost allocation rules that will not continue to imperil the timely development of renewable generation.

In addition, this rulemaking should consider adopting new cost allocation rules in non-ISO-RTO areas because the interconnection queues in many of those regions are similarly paralyzed in large part due to the same uncertainty about the cost of the upgrades that the customer will need to pay for in advance, subject to reimbursement as much as 20 years later, and the fact that the first users will pay for the entire cost. ACORE, therefore, urges the Commission to advance the ANOPR proposal and issue a notice of proposed rulemaking implementing the reforms described herein as expeditiously as possible.

III. CONCLUSION

For the foregoing reasons, ACORE respectfully requests that the Commission accept these comments and issue a notice of proposed rulemaking including the reforms proposed herein, as soon as practicable.

Respectfully submitted,

<u>/s/ Larry F. Eisenstat</u>

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EXHIBIT 1

Americans for a
Clean Energy Grid

JANUARY 2021

PLANNING FOR THE FUTURE

FERC'S OPPORTUNITY TO SPUR MORE COST-EFFECTIVE TRANSMISSION INFRASTRUCTURE

"This paper from Americans for a Clean Energy Grid represents a true milestone on the path toward a cleaner energy future. We hope these recommendations will kick-start a conversation among policymakers and stakeholders — a dialogue that needs to happen as soon as possible. ACEG looks forward to continued engagement with diverse stakeholders to achieve our shared vision of a cleaner energy future."

- **NINA PLAUSHIN**
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AC	Alternating Current
ACEG	Americans for a Clean Energy Grid
AEMO	Australian Energy Market Operator
BCA	Benefit-Cost Analysis
BRP	Baseline Reliability Projects
CAISO	California Independent System Operator
CLCPA	Climate Leadership and Community Protection Act
CREZ	Competitive Renewable Energy Zones
DC	Direct Current
DFAX	Distribution Factor
DPP	Definitive Planning Phase
EIA AEO	U.S. Energy Information Administration's Annual Energy Outlook
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GET	Grid-Enhancing Technologies
GHG	Greenhouse Gases
GI	Generator Interconnection
GW	Gigawatt
HVDC	High Voltage Direct Current
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	ISO New England
ITP	Integrated Transmission Plan
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
MEP	Market Efficiency Projects
MISO	Midcontinent Independent System Operator
MIT	Massachusetts Institute of Technology
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Projects
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Council
NIMBY	"Not In My Backyard"
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection
REBA	Renewable Energy Buyers Alliance
ROFR	Right of First Refusal
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
TPL	Transmission Planning
TWh	Terawatt-hour
U.S. DOE	United States Department of Energy
U.S. EIA	United States Energy Information Agency
VER	Variable Energy Resources
VOLL	Value of Lost Load
WATT Coalition	Working for Advanced Transmission Technologies Coalition

I. Executive Summary

A. The time has come for the Federal Energy Regulatory Commission (FERC) to build on its previous orders and strengthen transmission planning through a new nationwide transmission planning and cost allocation rule

Over the last 25 years, four major FERC orders, No. 888, 2000, 890 and 1000, each made incremental progress building regional transmission infrastructure, moving the industry away from its past balkanized structure with relatively weak connections between utility systems towards a more reliable and efficient system allowing for more regional exchange of power. As we look to the future, much more regional and inter-regional power exchange will be needed for national energy security, reliability, resilience, cost-effectiveness, and economic competitiveness. A decade after Order No. 1000's issuance, the nation faces new challenges and it is clear that neither the current infrastructure nor the rules governing its development match this need.

Numerous studies, as well as the experiences of regional planning entities, demonstrate that more robust interregional infrastructure is needed to ensure system resilience and reliability, and would yield substantial consumer benefits and help ensure affordable rates for customers if built. The combination of an aging transmission system and a changing resource mix heighten the need for proactive planning of regional and inter-regional transmission infrastructure. While a large amount of transmission infrastructure built in the 1960s and 70s is due for replacement, simply rebuilding this infrastructure is inefficient in light of a changing resource mix and shifting demand patterns. By all accounts, wind and solar resources will become a much larger portion of the resource mix in the future, and electrification of transportation and buildings will substantially increase demand. These trends magnify the benefits of building large regional and inter-regional transmission infrastructure to connect resource rich areas with load centers.

For all of the best efforts of the Commission and regional planning authorities, the current set of transmission regulations have resulted in inadequate levels of infrastructure that have burdened the interconnection process with the task of planning new network facilities — a task that should instead take place in the planning process. Further, existing regulations have created a system that disproportionately yields projects that address only local needs, that address reliability without more broadly assessing other benefits, or that simply replace old retiring transmission assets with the same type and design despite the potential for larger projects to more cost effectively meet the same needs. While local projects, reliability projects, and asset replacements will continue to be necessary, there is an opportunity to make better use of valuable existing rights of way, install newer technologies as assets are replaced, provide greater transparency and guidance over transmission expenditures, and reconfigure the grid to vastly increase regional and inter-regional delivery capacity. This would improve the cost effectiveness of new transmission investments for customers, reducing congestion, and enhancing reliability.

To achieve these outcomes, the Commission should undertake a comprehensive rulemaking to reform planning, cost allocation, and review of transmission. Reforms designed to ensure adequate, cost-effective investment in transmission infrastructure takes place are necessary for rates to be "just and reasonable" and consistent with the Federal Power Act's requirements. The Commission has an obligation to find under Section 206 of the Federal Power Act that current tariffs are unjust and unreasonable, and must be replaced with new transmission planning, cost allocation, and review guidelines. Reforms to ensure that regional and interregional planning processes better assess future needs, evaluate a full range of solutions, and focus on increasing cost effectiveness of new infrastructure for customers are well within the Commission's statutory authority, and its mandate to identify and serve the interests of electricity consumers.

B. A new comprehensive FERC planning rule should establish basic guidelines for transmission planning processes to ensure they meet future needs

The Commission should build on its longstanding work to improve regional and interregional transmission planning. Beginning with an industry of separate vertically integrated utilities, with around 500 owners of transmission, FERC began to foster regional exchange of power in the mid-1990s. Order No. 888, issued in 1996, encouraged "Regional Transmission Groups"[1] and "Independent System Operators"[2] with transmission planning coordination functions.[3] Order No. 2000, issued in 1999, encouraged the voluntary formation of Regional Transmission Organizations with transmission planning as a core function, both for reliability and efficiency.[4] Order No. 890, issued in 2007, established a set of more specific transmission planning principles that help to facilitate stakehold-

1 The Commission's 1994 Regional Transmission Group Policy Statement was an important precursor to Order No. 888.

2 Throughout this paper, we refer to RTOs and ISOs together simply as "RTOs."

3 *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC ¶ 61,080, April 24, 1996.

4 *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285, December 20, 1999.

er input and help ensure a more efficient mix of transmission infrastructure. It requires transmission planning processes to be open and transparent, provide for coordination between entities through information exchange and other practices, and utilize economic planning studies to evaluate projects.[5] Order No. 1000, issued in 2011, built on these principles by enacting a series of reforms designed to "identify and evaluate transmission alternatives at the regional level that may resolve the region's needs more efficiently or cost-effectively than solutions identified in the local transmission plans of individual public utility transmission providers,"[6] and requiring greater interregional coordination. These signature orders, issued by bipartisan commissions led by Chairs from both parties, have all explicitly endeavored to bolster regional transmission infrastructure for reliability and efficiency of the overall power system.

We now have ample evidence to see that the current transmission planning regulations leave a large gap remaining between what is being done and what is needed to address current and future needs. Regions have taken a wide variety of approaches to implementing the orders, and their collective experience has yielded important lessons. The time has come to build on the experience from these four major FERC planning orders and to take another step in reforming the planning processes to ensure that they yield just and reasonable solutions. In particular, the time has come to apply those lessons to yield greater development of region-spanning and inter-regional transmission capacity, and a sharper focus on ensuring that new development is as cost effective as possible.

The Commission should undertake a rulemaking to provide greater specificity in how regional and interregional planning processes must be conducted, adding four new pillars to these planning processes to ensure that planning properly identifies infrastructure that best meets future needs:

1. ***A new FERC rule should require planning processes to rely upon the best available data and forecasting methodologies.***

Regional planning entities' implementation of Order No. 1000 has shown that many regions fall short in identifying transmission needs based on assessments of plausible futures that are as accurate as possible. Changes in the resource mix driven by public policies and utility resource plans, growth in electric vehicles and building heating, quantity and location of generation in interconnection queues, and other changes to electrici-

5 *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 18 CFR Parts 35 and 37, at PP 418-601, February 16, 2007.

6 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 78, July 21, 2011.

ty demand and supply are important factors for which information is publicly available. Failing to fully incorporate these factors into planning leads to unjust and unreasonable outcomes because it yields infrastructure that will not meet future needs as cost effectively as possible. Rather than focus on the status quo, planners should incorporate the best available information about changing system needs as they assemble plans. The Commission should require planning entities to evaluate needs based on a range of reasonable planning scenarios based on plausible futures that cover the full range of factors that are likely to influence future demand and resource mix. The Commission should also require transmission planners to account for project siting considerations and information about new technologies, and non-transmission alternatives that may be funded outside of the planning process as key inputs. In short, planning processes must be about the future in order to be deemed just and reasonable.

2. ***A new FERC rule should require planning authorities to consider all of the benefits of transmission together.***

Planning entities generally employ siloed planning processes that often only partially evaluate the benefits of transmission projects by classifying projects as "reliability," "public policy," or "economic" projects. This siloed approach leads to unjust and unreasonable outcomes by failing to consider the economies of scope, where transmission typically provides multiple benefits that span these artificial categories. While planning entities may continue to provide for cost allocations that appropriately reflect benefits, and provide individual assessments of lines for permitting purposes, the Commission should ensure that transmission needs and solutions are identified in a manner that recognizes all of the multiple benefits of all types of transmission projects.

3. ***A new FERC rule should require transmission planning entities to evaluate all available solutions, including new physical infrastructure options and grid-enhancing technologies, within regional transmission plans to more efficiently serve customers.***

Current approaches are unjust and unreasonable by failing to consider lower cost or better performing options, and should be changed to include them.

4. ***A new FERC rule should direct transmission planning entities to select a portfolio of solutions for each regional and interregional transmission plan that is likely to maximize aggregate net benefits.***

The Commission should direct all planning entities to engage in portfolio assessments and benefit-cost analysis, providing guidelines with regard to how they should do so.

To ensure consumers benefit from transmission plans, benefit-cost analysis should be performed using methods that address uncertainty by quantifying benefits and costs in a range of plausible future scenarios. All planning entities should be required to adhere to a minimum set of best practices that ensure that all benefits will be quantified across the full life of the applicable infrastructure. Innovations in the full and accurate quantifications of transmission-related benefits should be encouraged.

C. A new FERC rule should continue to adhere to the principle that transmission costs must be allocated in a manner roughly commensurate with benefits in a way that recognizes the broad benefits that are created by large regional and interregional transmission infrastructure, while providing planning entities with flexibility in developing methodologies that adhere to this standard

FERC Order No. 1000 policies on cost allocation are largely workable as long as the planning reforms discussed herein are accomplished. The current approach for transmission included in regional plans, as dictated in a set of court decisions, is that cost allocation should be roughly commensurate with benefits received. While the Commission should require all planning entities to better quantify the benefits of new transmission infrastructure, it should refrain from requiring that the costs of new infrastructure be allocated in a manner that matches these benefits based on overly narrow metric or with exacting precision on a project-by-project basis. Instead, it should continue to require that overall costs of the new transmission infrastructure be allocated in a manner roughly commensurate with benefits. Therefore, as the Commission carries out reforms to transmission regulation, it should largely adhere to the basic approach that it has taken on cost allocation in Order 1000. Since interconnection processes, as governed by policy decisions made in Order 2003, do not follow beneficiary pays and instead follow "participant funding," this inconsistency should be rectified by a new rule. Thus the rule would be updating some provisions of Order No. 2003 and the interconnection processes of public utilities, as well as Orders No. 890 and 1000 on planning provisions.

To minimize analysis and help ensure that costs are allocated in a stable and predictable way, the Commission should direct planning entities to allocate the costs of portfolios of projects as a group, rather than proceeding only on a project-by-project basis. And to ensure that costs are not significantly mismatched with benefits, it should provide that single metrics such as load flow analysis may not be the sole basis of cost allocation, instead directing planning entities to use methods that account for a broader range of benefits that projects bring the whole system. To avoid cost-shifting and process disruption, the rule should assign costs to loads whether or not their affiliated company remains in a Regional Transmission Organization (RTO). Finally, the Commission should clarify that planning entities may allocate a portion of total costs in the future to generators and customers who utilize the new transmission infrastructure.

D. The Commission should ensure transmission investment is as cost-effective as possible

Consumer interests must be central to transmission policy, as the Federal Power Act is a consumer protection statute first and foremost. In recent years, as aging assets have been replaced, spending on transmission has increased without always providing for a process for consumers to know whether the expenses are justified or the type of upgrade is cost-effective. The Commission should build on Orders No. 888, 2000, 890, and 1000 by enacting further reforms to governance and oversight processes to ensure that costs incurred benefit customers. Broadly, these reforms should (i) ensure that local and end-of-life projects are more carefully evaluated as part of regional planning processes, to determine whether needs may be more efficiently served by larger, regional, and interregional projects rather than simple replacements; (ii)

ensure there is cost transparency and oversight of transmission costs and that public utility transmission providers are appropriately incented to pursue a more optimal mix of transmission solutions; (iii) consider targeted forms of performance based rate making that can incent efficiency in project development, (iv) develop a more collaborative approach to transmission planning and ownership among utilities and (v) ensure that interregional and possibly national transmission infrastructure is more seamlessly facilitated.

In particular, the Commission should reform the interregional planning process to eliminate the multi-stage process that currently prevents interregional projects from being constructed. To do so, the Commission should consider the formation of new interregional planning boards that have full authority to make section 205 filings to FERC that select and allocate costs for interregional transmission projects. This could allow projects to proceed without separately securing the approval of each individual RTO board.

The Commission should also take on a greater role in overseeing transmission planning. The Commission should better incent public utility transmission providers to pursue a more optimal mix of projects. To do this the Commission should consider evaluating the cost-effectiveness of local transmission projects where there is evidence that a project addresses a need that could be met more efficiently by a regional or interregional project. The Commission should consider performance-based ratemaking techniques to reward transmission owners that pursue more cost-effective solutions. Finally, recognizing the critical role that states play in transmission planning, the Commission should consider requiring planning entities to grant state representatives an explicit governance role in the regional transmission planning process. The Commission should solicit comments from stakeholders on whether this step is appropriate and if so, what in particular the Commission should require with regard to governance reforms.

II. The Commission should replace current tariffs with planning requirements that will achieve just and reasonable rates

Reforms are necessary to meet Federal Power Act requirements of just and reasonable rates given new circumstances and demands on the grid. It has become clear that transmission investments need to be better targeted to the regional and inter-regional levels. Study after study shows substantial net benefits of such infrastructure, while broader trends in generator additions and retirements dictate that new regional and inter-regional infrastructure will be needed to integrate low-cost wind and solar generation into the system. Electrification of transportation and building end-uses will create a heightened need for new infrastructure. Market forces alone will not meet these needs. Transmission infrastructure's large economies of scale and scope make it a natural monopoly that is deployed most cost-effectively via a central coordinator.[7] As a large amount of transmission infrastructure is replaced in the coming decades, the Commission must seize the opportunity to ensure that it is built to cost-effectively meet the needs of the future system. And yet, current tariffs are failing to meet these needs.

A. Just and reasonable rates require plans that include more high voltage long distance transmission given future resource portfolios

As laid out in Appendix A, a number of studies have been conducted that demonstrate that significantly greater levels of transmission construction would yield substantial benefits to customers and enhance grid reliability.

These studies all point to the need for significant expansion of regional and inter-regional transmission infrastructure in order to create a reliable, efficient power system given reasonable projections of future needs.

7 William W. Hogan, *Transmission Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal*, at 1, February 1, 2020.

B. System threats require plans that provide greater resilience

Power systems are subject to an increasing variety and magnitude of threats. While reliability protocols have traditionally planned for reliable operation during and after system contingencies such as large generator or transmission line outages, there are other types of threats that result in the need for more robust regional and interregional transmission.

A recent report by national security experts noted: "Our electricity grid's resilience—its ability to withstand shocks, attacks and damages from natural events, systemic failures, cyber attack or extreme electromagnetic events, both natural and man-made—has emerged as a major concern for U.S. national security and a stable civilian society."[8] The report described large scale transmission as a solution: "Transmission buildout is critical to resilience as it can relieve line overloading—or "congestion" in industry jargon—on the existing system, lessening the compounding risks that come with a strained grid that could then be tested by an extreme weather event or an attack incident. Moreover, by enabling further development of renewable energy resources over wider geographic areas, well-planned transmission expansion can make targeted attacks on the grid more difficult to plan and carry out."[9]

When the Commission opened a proceeding about system resilience, grid operators and experts emphasized first and foremost the importance of robust regional and interregional transmission in protecting against modern threats. For example:

- NYISO: "[R]esiliency is closely linked to the importance of maintaining and expanding interregional interconnections, [and] the building out of a robust transmission system;"[10]
- ISO-NE: "The system's ability to withstand various transmission facility and generator contingencies and move power around without dependence on local resources under many operating conditions . . . results in a grid that is, as defined by the Commission, resilient."[11]
- PJM: "Robust long-term planning, including developing and incorporating resilience criteria into the [Regional Transmission Expansion Plan], can also help to protect the transmission system from threats to resilience."[12]

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8 NCGR, *Grid Resilience: Priorities for the Next Administration*, at 1, 2020.

9 *Ibid.*, at 42.

10 *Response of the New York Independent System Operator, Inc.*, Docket No. AD18-7, at 4, March 9, 2018.

11 *Response of ISO New England Inc.*, Docket No. AD18-7, at 15, March 9, 2018.

12 *Comments and Responses of PJM Interconnection, L.L.C.*, Docket No. AD18-7, at 49, March 9, 2018.

- SPP: “The transmission infrastructure requirements that are identified through the [Integrated Transmission Plan (ITP)] process are intended to ensure that low cost generation is available to load, but the requirements also support resilience in that needs are identified beyond shorter term reliability needs. For example, the ITP identified the need for a number of 345 kV transmission lines connecting the panhandle of Texas to Oklahoma. These lines were identified as being economically beneficial for bringing low-cost, renewable energy to market, but their construction has also supported resilience by creating and strengthening alternate paths within SPP.”[13]

- Brattle Group analysts: “The power system can be vulnerable to disruptions originating at multiple levels, including events where a significant number of generating units experience unexpected outages. The transmission system provides an effective bulwark against threats to the generation fleet through the diversification of resources and multiple pathways for power to flow to distribution systems and ultimately customers. By providing customers access to generation resources with diverse geography, technology, and fuel sources, the transmission network buffers customers against extreme weather events that affect a specific geographic location or some external phenomenon (unavailability of fuel and physical or cyber-attacks) that affect only a portion of the generating units.”[14]

Similarly, a National Academies of Sciences study of power system resilience noted the need for planning improvements to protect against modern threats.[15] The report draws several conclusions that weigh toward enacting reforms to ensure that regional transmission plans improve system resilience:

- “[L]arge-scale physical destruction of key parts of the power system by terrorists is a real danger.”[16]

- “[T]he risks posed by cyber attacks are very real and could cause major disruptions in system operations.”[17]

- “The probability, intensity, and spatial distribution of many of the hazards that can disrupt the power system are changing. These changes are due in part to the consequences of ongoing climate change. Traditional measures, based on an assumption

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13 *Comments of Southwest Power Pool, Inc. on Grid Resilience Issues*, Docket No. AD18-7, at 8, March 9, 2018.

14 Mark Chupka and Pearl Donohoo-Vallett, *Recognizing the Role of Transmission in Electric System Resilience*, at 3, May 9, 2018.

15 National Academies of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation’s Electricity System*, The National Academies Press, 2017.

16 *Ibid.*, at 64.

17 *Ibid.*

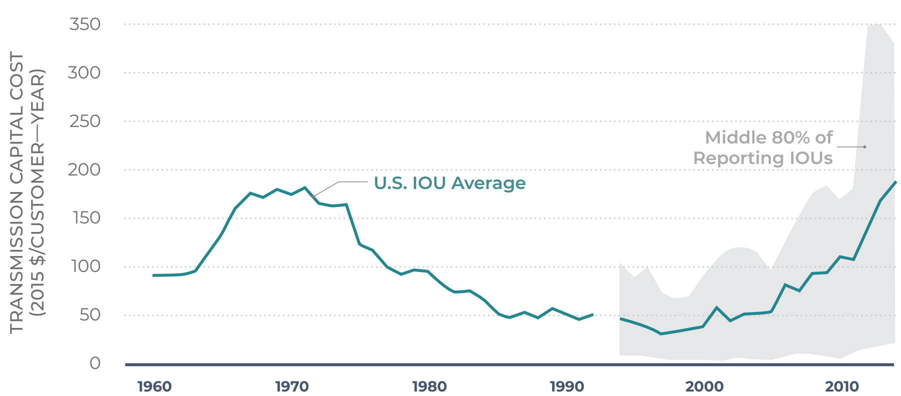
of statistical stationarity (e.g., 100-year flood), may need to be revised to produce measures that reflect the changing nature of some hazards."[18]

- "As the complexity and scale of the grid as a cyber-physical system continues to grow, there are opportunities to plan and design the system to reduce the criticality of individual components and to fail gracefully as opposed to catastrophically."[19]
- "In most cases, an electricity system that is designed, constructed, and operated solely on the basis of economic efficiency to meet standard reliability criteria will not be sufficiently resilient."[20]

C. The combination of an aging transmission system and a changing resource mix heighten the need for proactively planned transmission

The United States experienced a transmission construction boom in the 1960s and 70s, with the average annual investment cost of new transmission system capital infrastructure for U.S. Investor Owned Utilities climbing to nearly $200/customer-year at its peak during the late 1960s and early 70s before falling to less than $100/customer-year in the 1980s and 90s.[21]

FIGURE 1 Average Cost of Investment in New Transmission System Capital Infrastructure



Copyright The University of Texas at Austin, 2016

18 *Ibid.*, at 65.

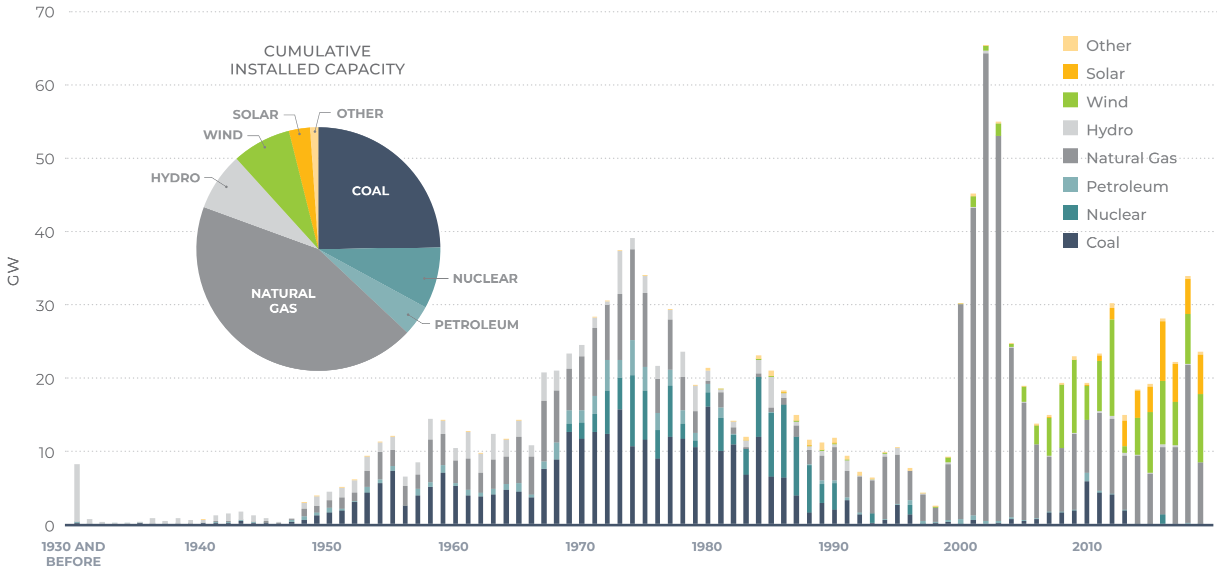
19 *Ibid.*, at 67.

20 *Ibid.*, at 71.

21 Robert L. Fares and Carey W. King, *Trends in Transmission, Distribution, and Administration Costs for U.S. Investor Owned Electric Utilities*, at 8, August 2016.

This construction boom coincided with a wave of power plant construction that consisted largely of coal, nuclear, and some gas facilities.[22] Transmission integrated these power plants with the system, building an infrastructure network well suited to large, centrally located power plants.

FIGURE 2 U.S. Electric Utility and Independent Power Producer Generating Capacity by Initial Operating Year[23]

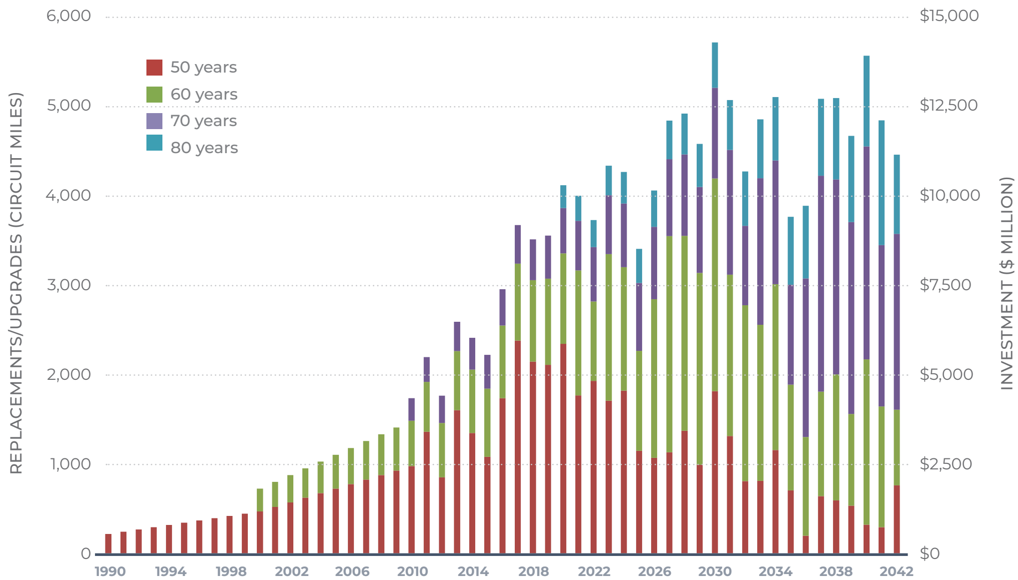


As this infrastructure ages, with transmission built in the 1960s now more than 50 years old, the system is facing a widespread need for maintenance, repair, and reconstruction. Yet as a second wave of transmission construction is playing out, new construction is too frequently focusing on simply rebuilding transmission infrastructure of the past, or addressing needs based on the current resource mix.

22 U.S. Energy Information Administration, *Most U.S. Nuclear Power Plants Were Built Between 1970 and 1990*, April 27, 2017.

23 U.S. Energy Information Administration, *Form 860*. Grid Strategies uses final 2019 data to aggregate electric generating units and their associated generating capacity by resource type and operating year.

FIGURE 3 **Projected Circuit Miles Replaced/Upgraded and Total Projected investment ($ million)**[24]

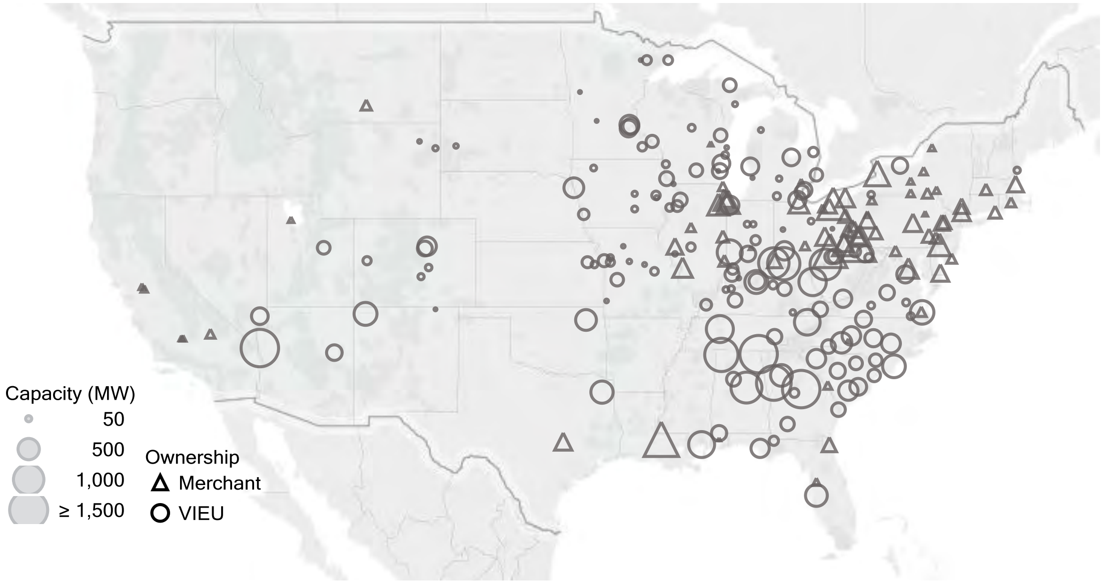


Such planning, blind to the retirement of aging generating plants and the forces shaping the future resource mix, is a recipe for a suboptimal infrastructure network that fails to meet future needs. As detailed in the U.S. Department of Energy's 2017 Staff Report to the Secretary on Electricity Markets and Reliability, a substantial portion of the nation's coal fleet has recently retired, and more coal plants and a significant number of nuclear plants are slated for retirement in the next 10 years.[25]

24 AEP, *Transmission's Future Today*, at 5, 2015, citing Johannes Pfeifenberger, Judy Chang, and John Tsoukalis, *Dynamics and Opportunities in Transmission Development*, December 2, 2014 (Assumes circuit mile costs equal to those of new lines).

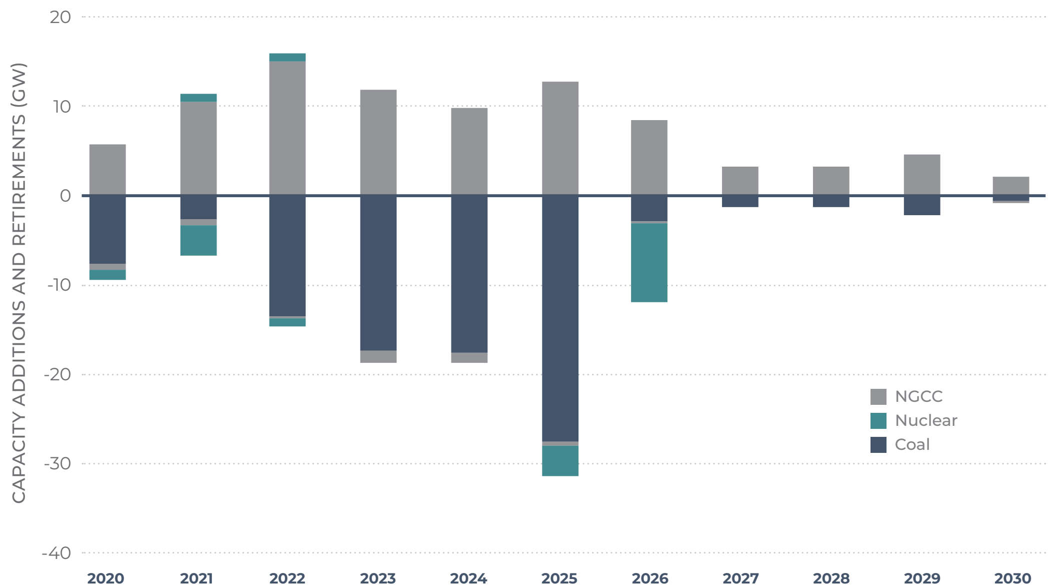
25 *See* U.S. Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017.

FIGURE 4 **Location of Coal Retirements (2002-2016)**[26]



26 *Ibid.*, at 21.

FIGURE 5 **Capacity Additions and Retirements from EIA Annual Energy Outlook (AEO) 2020 Reference Case**[27]

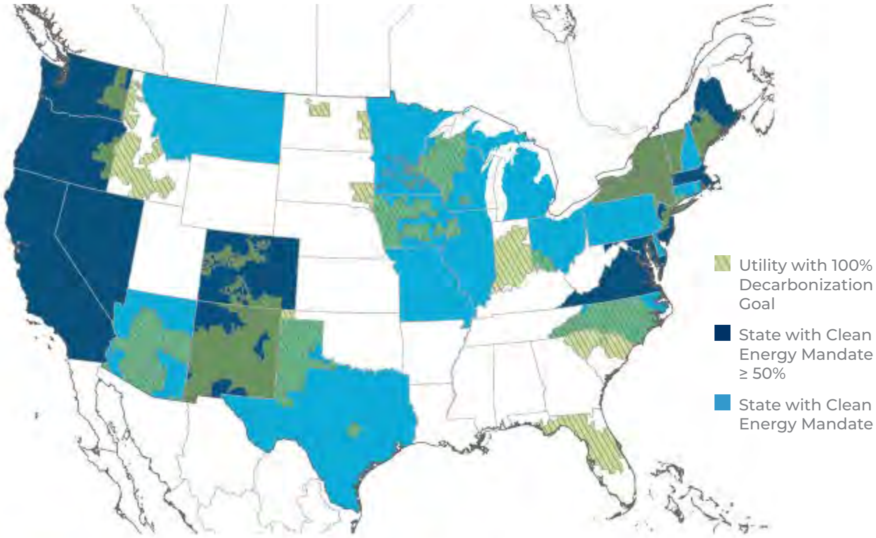


At the same time, wind and solar resources are rapidly proliferating. Wind and solar energy costs have fallen 70 and 89 percent, respectively, in the last ten years, from 2009 through 2019.[28] A number of additional factors are spurring their deployment as well, including public policies and corporate and utility procurement targets, as shown in Figure 6 below.

27 U.S. Energy Information Administration, *Annual Energy Outlook 2020*, Reference Table 9. Grid strategies uses EIA-projected electric generating capacity data to aggregate annual Coal, NGCC, and nuclear additions and retirements through 2030. The figure includes both "planned" and "unplanned" or projected additions and retirements.

28 Lazard, *Lazard's Levelized Cost of Energy Analysis - Version 13.0*, at 8, November 2019.

FIGURE 6 **U.S. States with Clean Electricity Mandates & Utilities with Decarbonization Goals, 2020**[29]



Source: WRI and Smart Electric Power Alliance. Updated on April 17, 2020

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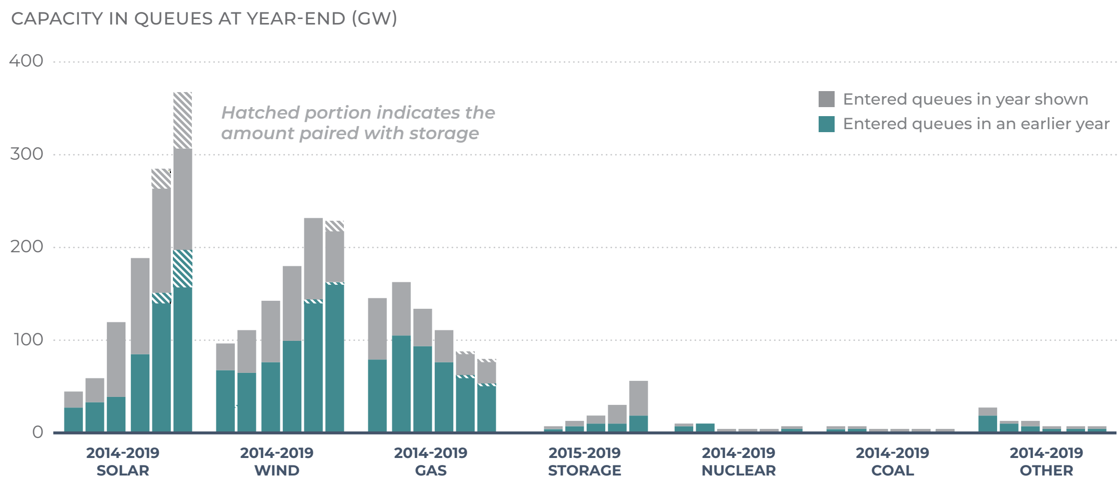
29 Lori Bird and Tyler Clevenger, *2019 Was a Watershed Year for Clean Energy Commitments from U.S. States and Utilities*, December 20, 2019.

Wind and solar resources make up the majority of resources in interconnection queues across the country.[30] There were 734 gigawatts (GW) of proposed generators waiting in interconnection queues nationwide at the end of 2019, almost 90% of which are renewable and storage resources as shown in Figure 7 below. 168 GW of solar and 64 GW of wind projects entered interconnection queues in 2019. The U.S. EIA forecasts that wind and solar will make up over 75% of new capacity additions in 2020,[31] and these resources will likely make up the lion's share of new additions for the foreseeable future.[32]

FIGURE 7 **Capacity in Queues at Year-End by Resource Type**



Source: Berkeley Lab review of interconnection queues

Note: Not all of this capacity will be built

Because the best locations for wind and solar resources are significantly different from those of retiring coal and nuclear resources, reconstructing the grid of the past is a poor match for future needs. Transmission has a long infrastructure life, so the infrastructure built today should be designed with the next 50 years in mind.

30 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. *See* also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

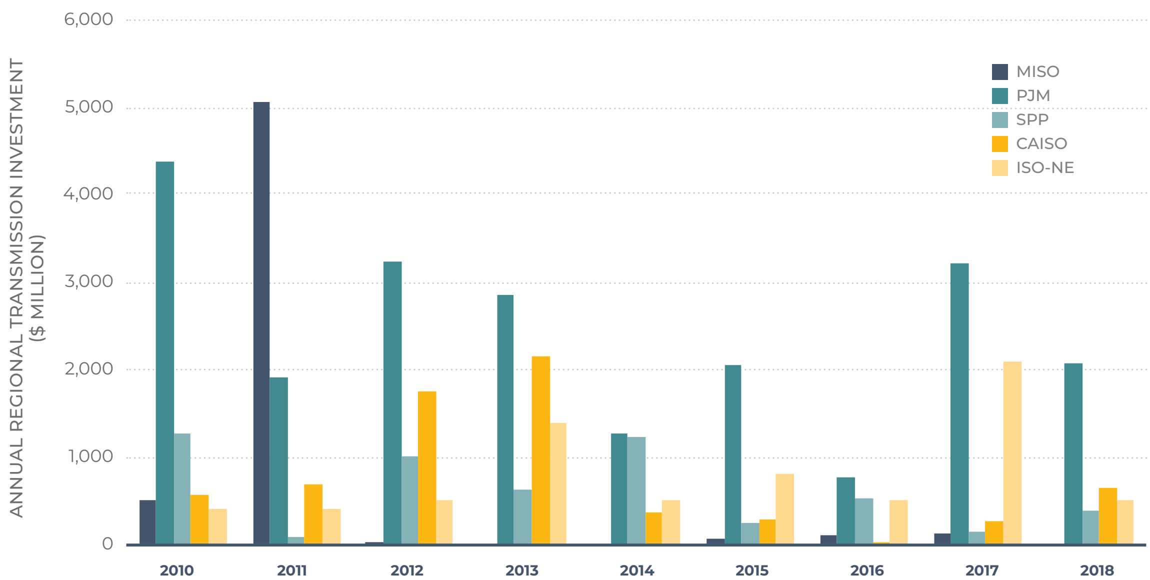
31 U.S. Energy Information Administration, *New Electric Generating Capacity in 2020 Will Come Primarily From Wind and Solar*, January 14, 2020.

32 *See*, e.g., U.S. Department of Energy, *Wind Vision: A New Era for Wind Power in the United States*, Figure 3-24 at 171, March 12, 2015.

D. The vast majority of new projects serve local needs or reconstruction of aging facilities, despite the large and growing need for bigger regional and inter-regional capacity

Despite the many benefits and economies of scale that regional and interregional transmission would bring, regional transmission investment (when excluding local transmission investments not subject to regional planning processes) has been stable or declining over the past decade.

FIGURE 8 Annual Regionally-Planned Transmission Investment in RTOs/ISOs ($ million)[33]



And while total annual transmission investment levels remain relatively robust, the majority of that investment has been in local transmission and low-voltage projects, planned without a full regional assessment that examines their cost-effectiveness relative to regional alternatives, or in regional infrastructure that is planned to meet reliability needs without assessing how to maximize other types of benefits, or that simply rebuilds or

33 Not all RTOs/ISOs provide regional transmission investment information. *See* Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, *Section 206 Complaint and Request for Fast Track Processing*, at 31-32, January 21, 2020; PJM, *Project Statistics*, at 6, January 10, 2019; Lanny Nickell, *Transmission Investment in SPP*, at 5, July 15, 2019; CAISO, *ISO Board Approved Transmission Plans*, years 2012-2021 available under "Transmission planning and studies" section of webpage; CAISO, *2011-2012 Transmission Plan*, March 14, 2012; CAISO, *Briefing on 2010 Transmission Plan*, 2010; and ISO New-England, *Transmission*, accessed October 2020.

replaces existing infrastructure.[34] While utilities are understandably investing in local reliability upgrades when those needs are not addressed via regional and inter-regional infrastructure, this approach to transmission infrastructure investment results in higher total energy bills for customers than would result from more forward-looking, holistic transmission planning.

According to analysis by the Brattle Group, 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 or with limited ISO/RTO stakeholder engagement."[35] Further, the remaining transmission infrastructure that was included within regional transmission plans was skewed largely toward local projects, and projects built to meet near-term reliability needs. In addition, the Brattle Group analysts found that 97% of all transmission approved in their study period was not subject to a competitive selection process, either because it was built to address a near-term reliability need, upgraded existing infrastructure, or fell below RTO thresholds for competitive process, such as a specified voltage level.[36] Some RTOs do include RTO review of local projects,[37] but this is not consistent across Planning Authorities.

E. Generation interconnection processes are stretched to their breaking point

The lack of large regional transmission projects that connect resource rich areas with load centers has put the onus of building upgrades to interconnect wind and solar generators on generation interconnection processes. This has over-burdened them with a task they were never intended to perform: the job of planning the regional network in addition to the more local interconnection-related facilities.

Interconnection studies for individual generators (or groups of generators) are increasingly identifying costly regional upgrades and are projected to do so with greater fre-

34 Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 4, April 2019 ("Significant investments have been made, but relatively little has been built to meet the broader regional and interregional economic and public policy needs envisioned when FERC issued Order No. 1000. Instead, most of these transmission investments addressed reliability and local needs.")

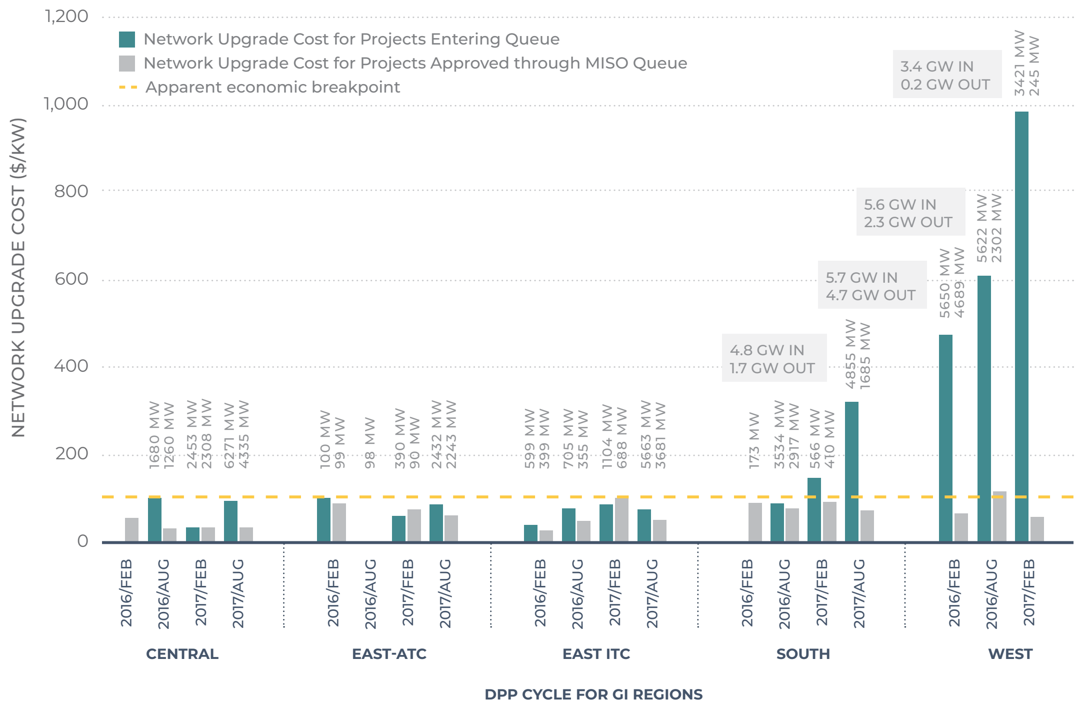
35 *Ibid*., 6-7.

36 *Ibid*., 17-20. *See also* MISO, *MTEP20 Appendix A - New Project List*, n.d., and PJM, *2019 Project Statistics*, at 3, May 12, 2020.

37 *See* MISO, *Business Practices Manual Transmission Planning*, BPM-020-r21, at 22, January 1, 2020. "In its role as the Planning Coordinator (PC), MISO will evaluate all bottom-up projects submitted by Transmission Owner(s) and validate that the projects represent prudent solutions to one or more identified Transmission Issues. In some situations, MISO, as the Planning Coordinator, may also recommend certain bottom-up projects if MISO analysis determines that additional expansion is necessary to comply with the NERC or regional reliability standards. Furthermore, MISO may also recommend alternative solutions to bottom-up projects submitted by Transmission Owner(s), and the expansion planning process will consider those alternative solutions along with the submitted bottom-up projects."

quency in the future. Costly system upgrades are not easily achieved by the interconnection process, which relies on participant funding — the practice of allocating project costs only to those who volunteer to pay them.[38] Interconnection costs are governed by Order No. 2003, which established the "at or beyond rule," pursuant to which the costs of facilities and equipment that lie between the generation source and the point of interconnection with the transmission network are born by the incoming generator.[39] While Order No. 2003 set a default rule that transmission owners would cover the cost of "network upgrades," (equipment "at or beyond" the point of interconnection), it gave RTOs "flexibility to customize . . . interconnection procedures and agreements to meet regional needs."[40] Some RTOs have since adopted methodologies that place the lion's share of network costs on the interconnecting generator.[41]

FIGURE 9 **GI Network upgrade Costs ($/kW) for Recent MISO DPP Cycles[42]**



38 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 715, July 21, 2011 (defining "participant funding").

39 *See Ameren Services Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018).

40 *Ibid.*

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

42 ITC, *MISO Generation Queue and Renewable Generation: Update to the Advisory Committee*, at 5, May 20, 2020.

The system of funding major transmission upgrades through the generation interconnection process is ineffective for several reasons. First, large new transmission additions create broad-based regional benefits, so charging only interconnecting generators for this equipment requires them to fund infrastructure that others benefit from. This is the classic “free rider” problem in economics that makes it efficient to broadly allocate the cost of “public goods” like transmission, roads, water and sewer networks, etc. Second, it relies upon a study process that is highly unpredictable for participating generators, who do not know whether or not their interconnection request will require large upgrades. When studies reveal significant costs, generators tend to drop out of the process, necessitating restudies for all remaining generators and prompting delays (and potentially higher costs) for projects that are part of the same interconnection class year or further down in the interconnection queue. Third, there is a timing mismatch where transmission can take over five years, and it is not possible to know in advance which generation owners might want to connect at that point in the future. Finally, it misses opportunities to design new infrastructure in a more cost-effective fashion and of sufficient scale that maximizes all benefits of transmission, including reliability and economic benefits, and accommodates all likely new generation rather than just the particular generator(s) supporting the upgrades.

The current interconnection process simply does not work well when there is not adequate regional transmission capacity or a functioning mechanism to plan and pay for regional transmission. Without transmission planning reform that links the interconnection and transmission planning processes and eliminates the use of participant funding for significant system upgrades in the interconnection process, interconnection processes will become mired in ever-longer delays.[43]

43 Jay Caspary, Michael Goggin, Rob Gramlich, Jesse Schneider, *Disconnected: The Need for a New Generator Interconnection Policy*, January 2021.

III. FERC planning rule reforms

As the nation's resource mix evolves, the transmission system should be built to address future needs. Well-known commitments by major end use customers, utilities, cities, and states in support of net-zero or minimal carbon futures have not been adequately captured in grid planning scenarios. Information about the changing costs of different resource types are also widely recognized as driving significant system changes. Transmission plans can only yield reliable and efficient outcomes if they account for widely known trends and reasonable projections of future transmission needs. In short, plans should be about the future.

In most cases today, regional planning is limited to near term knowns and protecting firm service using scenarios which do not adequately incorporate likely future changes. In Appendix B, we describe and evaluate existing processes. In this section, we suggest reforms the Commission should enact to encourage better regional planning.

A. Integrated transmission planning should consider all benefits of transmission together

Many regions have segregated transmission planning studies for economic, reliability, public policy, and generator interconnection (GI) transmission projects. As discussed further in Appendix B, regions have separate planning processes for "Reliability" and "Economic" projects, and many regions have additional processes for "Public Policy" projects. Requiring a transmission project to be categorized as only one type of project fails to recognize all of the values and benefits of a transmission investment.[44] This siloed approach fails to consider the economies of scope across different categories and results in more poorly targeted transmission investments are accordingly less value per dollar spent by customers relative to regions that have taken an integrated approach to planning a network that optimizes across all categories of benefits.

While some regions have a process for "Multi-Value" projects, recognizing the fact that a single project may bring many types of benefits, these processes are not regularly used.

44 For example, *see* Judy W. Chang, Johannes P. Pfeifenberger, and J. Michael Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, Appendix A, July 2013.

Rather than being the exception, they should be the norm. FERC should require regional planning entities, as a general course of practice, to plan projects in a multi-value frame that considers all of the different benefits they are capable of providing.

B. Transmission needs should be determined with the best available data and scenario-based forecasting methodologies

A primary reason that the regional planning process has yielded few projects is that the scenarios modeled at the regional level do not reflect a reasonable projection of future supply and demand. To remedy this, the Commission should direct regional planning entities to carry out regional planning using scenarios constructed according to the best available data and forecasting methodologies. While reliability planning processes must necessarily evaluate solutions according to projections of the status quo future system across a variety of time scales, the economic planning process should provide an overlay to this process that is based on a more realistic assessment of future system needs, including resource mix projections that incorporate the best available data on future market trends. These should include (i) technology costs, (ii) public policies, (iii) corporate and utility procurement targets, (iv) interconnection queues, (iv) investments outside the planning process in non-wires alternatives, and (v) retirement projections. Demand projections must include reasonable electrification projections, accounting for market trends as well as public policies that require or incentivize electrification of buildings and transportation end uses. Planning entities should formulate a variety of reasonable future resource and demand mixes, recognizing the uncertainty inherent in the planning processes, identifying transmission needs across a wide range of plausible scenarios.[45]

45 *See* Johannes Pfeifenberger, Judy Chang, and Akarsh Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, Appendix B at B-1, April 2015; and Johannes Pfeifenberger and Judy Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon Constrained Future*, Section V at 17, June 2016.

Formulating these planning scenarios is challenging insofar as it will require synthesizing a range of factors to project future generation and supply mixes. But by working with National Labs, states, and stakeholders to formulate reasonable assumptions, planning entities can greatly improve upon status quo approaches. To help guide regional planning entities, the Commission could encourage National Labs to focus on developing scenario analysis that can be used by regions, specifying that such projections are likely to constitute the best available data and forecasting methodologies.

1. ***Plans should address needs according to reasonable estimates of the future resource mix***

Regional planning processes have tended to under-forecast the future mix of wind and solar. For example, in a 2019 planning assessment, SPP concluded that "[p]revious 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."[46] A variety of factors may contribute to this. Perhaps most significantly, planning processes may limit scenarios assessed to known generator interconnections and retirements, and fail to include new generation as part of the mix except insofar as needed to meet load growth.

For example, PJM's market efficiency planning process includes only facilities that have an "executed Interconnection Service Agreement or executed Interim Interconnection Service Agreement for which Interconnection Service Agreement is expected to be executed."[47] While PJM's methodology was adopted with the recognition that not all projects will come to fruition, protesting parties and the Market Monitor provided persuasive evidence that PJM's methodology will lead to inaccurate projections.[48] Likewise, SPP only includes generation resources in its economic models if they meet a set of criteria that includes "an effective Generator Interconnection Agreement," unless it grants a special case-by-case exemption.[49]

Such processes neglect the core function of the transmission planning process: to build infrastructure that connects the future resource mix to load. By default, generation that has secured interconnection agreements will have already agreed to pay for network upgrades necessary to integrate the generation. The generation that could benefit from

46 SPP, *2019 Integrated Transmission Planning Assessment Report*, at 2, November 6, 2019.

47 PJM, *Amended and Restated Operating Agreement of PJM Interconnection*, L.L.C., Schedule 6, § 1.5.7(i)(iv), effective date September 17, 2010

48 *PJM Interconnection, L.L.C.*, 166 FERC ¶ 61,104, at PP 14-20, February 12, 2019.

49 SPP, *Integrated Transmission Planning Manual*, § 2.2.1.4, July 20, 2017.

transmission planning is necessarily the generation deeper in the queue. Generator retirements also should not be ignored, as they are a major factor impacting grid planning. In many cases, new resources of a different type will be installed at the same substation or zone where aging generators are being idled and retired. The lead time to install replacement resources has been reduced for inverter-based resources such as wind, solar and battery projects, so in many cases likely generator retirement may be a useful indicator of future resource mix locations. The recent announcements by many utilities in support of clean energy mandates and goals will require a significant amount of generator retirements that are not reflected in current long-range resource plans incorporated into regional planning assessments, and public policies can likewise cause generation retirements.

Rather than permitting status quo modeling that assesses only generation built to meet new load, the Commission should require regions to carry out economic planning processes according to more realistic projections of retirements, utilizing the best available information, including generation interconnection queues,[50] to predict the set of resources most likely to meet the needs currently served by existing generation that is likely to retire. The Midcontinent Independent System Operator's (MISO's) planning process provides a general template of how regions can conduct such a process. While its Regional Resource Forecasting model formulates the region's baseline scenario using only "existing generators and future generators with a filed Interconnection Agreement and in-service date prior to the point in time represented by the model," and reflects retirement only of "existing generators with approved Attachment Y [retirement] Notices,"[51] the model is then used as the basis for "Futures" assessments that project a range of resource additions and subtractions based on cost inputs and other factors.[52] In such analyses, a base case used for reliability assessments that contains only known resource retirements and additions should be given zero weight, reflecting the fact that a projection that relies solely on known resource retirements and additions has virtually zero probability of coming to pass.

Future resource mix projections should also be required to incorporate public policies. FERC should go beyond the Order 1000 requirement that regions simply "consider" public policy, and require that they incorporate it into a holistic assessment of transmission needs. While some regions incorporate state renewable portfolio standards into their

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50 While interconnection queues will not perfectly match likely future generation, they are a data point that regional planning entities should critically evaluate along with other inputs.

51 SPP, *Integrated Transmission Planning Manual*, § 2.2.1.4, July 20, 2017

52 *See*, e.g., MISO, *MTEP19 Futures: Summary of Definitions, Uncertainty Variables, Resource Forecasts, Siting Process, and Siting Results*, n.d.

standard economic planning projections, not all regions do so.[53] Regions should account both for policies such as renewable portfolio or clean energy standards that encourage particular generation types, and also for emissions regulations that may cause the retirement of polluting resources, including federal, state, and local requirements. For example, NYISO incorporated peaker plant retirement scenarios into its most recent Comprehensive Reliability Plan, reflecting the likelihood that such plants would be impacted by state emissions regulations.[54] Local public policies are playing an increasing role in shaping the resource mix and should therefore be specifically accounted for by planning entities. Over "200 cities and counties have achieved or committed to 100 percent clean electricity," with the vast majority of these commitments having been made in the past three years.[55] With the increasing use of Community Choice Aggregation to enable such resource commitments, additional local commitments may become more likely in future years.

In addition, projections should reflect corporate and utility procurement targets. Incorporating such targets is necessary to accurately project future needs, which is required in order to ensure just and reasonable rates that reflect the right amount and type of infrastructure to serve those needs. Further, incorporating corporate and utility procurement targets will help facilitate an infrastructure mix that meets consumer preferences.

While MISO has recently proposed to incorporate corporate and utility procurement targets into its future planning scenarios,[56] most regions do not currently do so. Corporate procurement of renewables is a large and growing factor shaping future resource mix. Six utilities have adopted 100 percent clean energy or zero greenhouse gas emissions targets.[57] Corporations have signed power purchase agreements to procure over 21,000 megawatts of renewable capacity since 2018,[58] and will likely be seeking to procure thousands more in the coming years pursuant to renewable procurement targets. The Renewable Energy Buyers Alliance (REBA) has set a goal of catalyzing 60,000 megawatts of renewable energy projects by 2025.[59]

53 For example, PJM does not include public policies within its standard economic planning forecast, instead requiring any transmission driven by public policy needs to be funded separately by states. PJM, *Amended and Restated Operating Agreement of PJM Interconnection*, L.L.C., Schedule 6, § 1.5.9, effective date September 17, 2010.

54 NYISO, *2019-2028 Comprehensive Reliability Plan*, at 14-29, 2019.

55 UCLA Luskin Center for Innovation, *Progress Toward 100% Clean Energy in Cities & States Across the U.S.*, at 10-11, November 2019.

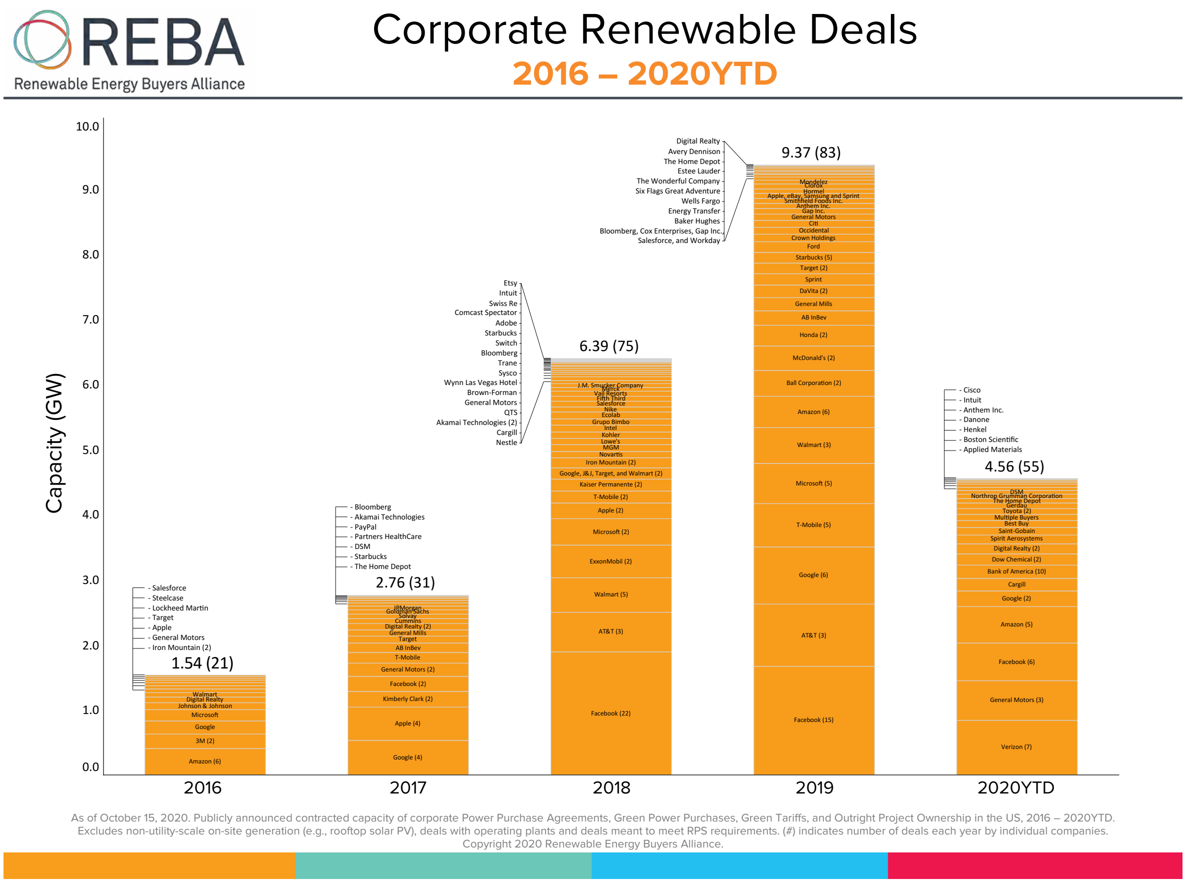
56 *See* MISO, *MISO Futures – Final*, Futures Siting Workshop, at 5, April 27, 2020, (incorporating utility and corporate procurement targets into Futures I and II).

57 UCLA Luskin Center for Innovation, *Progress Toward 100% Clean Energy in Cities & States Across the U.S.*, at 6, November 2019.

58 Renewable Energy Buyers Alliance, *REBA Deal Tracker*, accessed October 2020.

59 Renewable Energy Buyers Alliance, *Our Mission*, accessed Nov. 12, 2020. Corporate procurement goals can be more easily incorporated into regional transmission plans where companies have made time and location-specific commitments.

FIGURE 10 Corporate Renewable Deals (2016-2020)



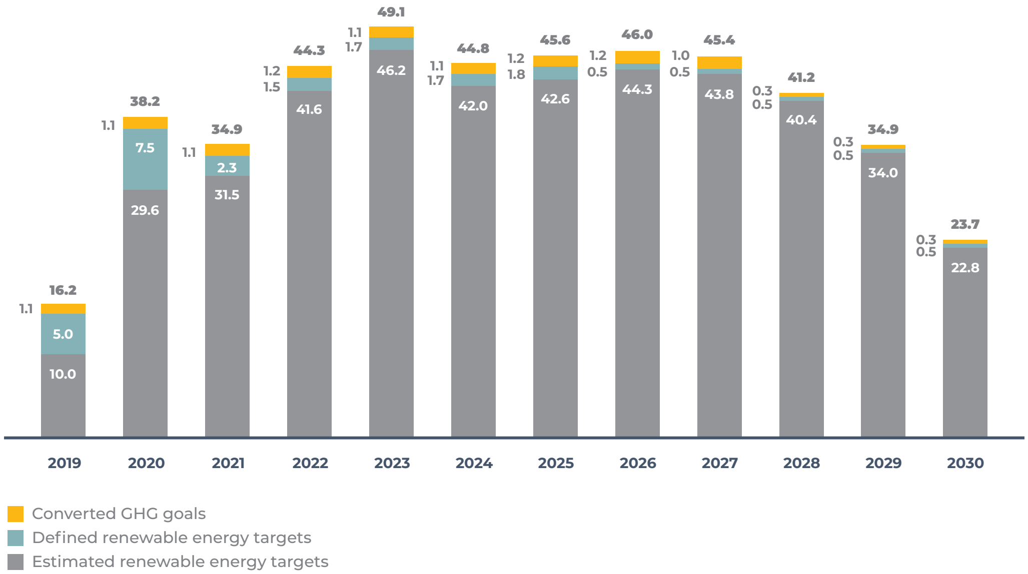
Credit: Renewable Energy Buyer's Alliance

Further, nearly half of Fortune 500 companies have set a greenhouse gas (GHG) reduction target.[60] Wood Mackenzie estimates that corporate and industrial renewable energy demand by the U.S. Fortune 1000 companies will be up to 85,000 megawatts by 2030.[61]

60 Nicolette Santos, David Gardiner and Associates, *Nashville Carbon Competitiveness*, at 7, September 2020.

61 Dan Shreve, *Analysis of Commercial and Industrial Wind Energy Demand in the United States*, at 5, August 2019.

FIGURE 11 Fortune 1000 Annual C&I Renewable Energy Procurement Requirements (TWh)



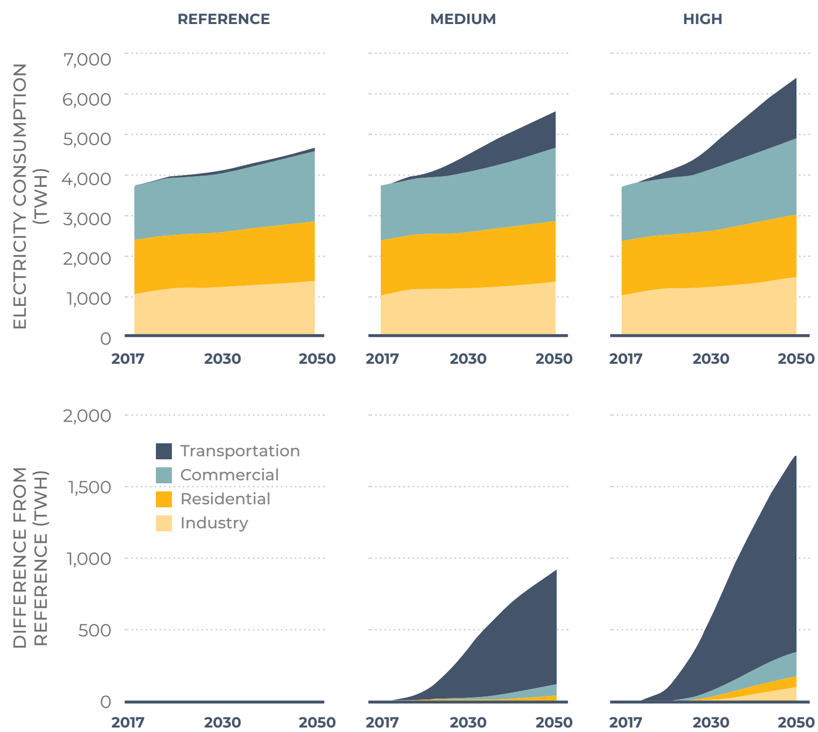
We are not aware of any reports that track total customer demand for particular resource types by region, so it is difficult to determine the extent to which such corporate targets will drive transmission planning needs. To fill this gap, the Commission should require regional planning entities to develop a process for estimating demand preferences from wholesale customers in their region. In sum, the Commission should require planning entities to plan for future resource mixes that respond to customers' preferences regarding supply sources, allocating costs appropriately, as described further in Section IV.

2. *Plans should incorporate the effects of electrification on electricity demand*

Electrification of transportation and buildings end-uses will have an enormous effect on future system needs. While regional transmission planning processes have made some strides forward to address this growing trend, they generally have not caught up to it and do not have adequate processes in place to ensure that demand projections will reflect reasonable electrification scenarios.

In its "medium electrification" case, which projects buildings and transportation electrification using only technology price forecasts and other factors without incorporating public policy, National Renewable Energy Laboratory (NREL) projects that transportation electrification will create nearly 1000 TWh of new demand in 2050, around a 25 percent increase from today's level, with building electrification more than making up for load reductions in the building sector caused by energy efficiency.[62]

FIGURE 12 **Annual U.S. Electricity Consumption (top) and Difference from Reference (bottom)**[63]



And national, state and local public policies will accelerate this trend. Recently passed state climate laws have included economy-wide emissions targets alongside generation sector requirements. For example, Maine's 2019 climate law requires the state to reduce GHG emissions to at least 80 percent below 1990 levels by 2050.[64] New York's Climate Leadership and Community Protection Act sets a target of net-zero emissions economy-wide by 2050.[65] In total, nine states and the District of Columbia have set targets of net zero economy-wide emissions by 2050 or sooner.[66]

62 Trieu Mai et al., *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*, at 60, 2018.

63 *Ibid.*, Figure 7.1 at 60.

64 *S.P. 550*, An Act to Establish the Maine Climate Change Council to Assist Maine to Mitigate, Prepare for and Adapt to Climate Change, 129th Maine Legislature, Legislative Document No. 1679, May 2, 2019.

65 *S. 6599*, An Act to Amend the Environmental Conservation Law, the Public Service Law, the Public Authorities Law, the Labor Law and the Community Risk and Resilience Act, in Relation to Establishing the New York State Climate Leadership and Community Protection Act, June 18, 2019.

66 John Podesta et al., *State Fact Sheet: A 100 Percent Clean Future*, Oct. 16, 2019.

Building codes are increasingly likely to incentivize or require electrification of some building segments, with the International Energy Conservation Code making its first ever electrification proposals for three features of its 2021 code.[67] New York City, the nation's largest local jurisdiction, has adopted a buildings efficiency standard that focuses on total building emissions and requires substantial reductions by 2030.[68] In California, "[m]ore than 50 cities and counties are considering requiring or encouraging all-electric new construction with local ordinances and zero-emission reach codes for buildings."[69] Furthermore, states and local jurisdictions also have a wide range of legal tools to electrify transportation fleets,[70] and are increasingly adopting plans to do so. For example, many states have adopted financial incentives for EV ownership, as well as incentives for EV charging infrastructure, often recoverable in rates.[71] California's governor recently signed an order banning sales of new gasoline cars by 2035.[72]

The Brattle Group analysts estimate that between $3 billion and $7 billion in annual incremental transmission investment will be need to meet increased demand caused by electrification between 2018 and 2030, with between $7 billion and $25 billion in annual incremental investment required between 2031 and 2050.[73]

In theory, reasonable electrification projections should already be guiding regional transmission planning processes, as they all include a load forecasting process to assess future demand.[74] In practice, however, load forecasting processes are not generally calibrated to capture the likelihood that electrification will drive a significant increase in future demand. Some regions, such as PJM, have begun to adjust their load forecasts to factor in electrification. PJM's forecast used for RTEP19 incorporates "an explicit adjustment for plug-in electric vehicle (PEV) charging in its peak and energy forecasts."[75] Building on these efforts, the Commission should require all regions to explicitly account for additional load from electrification of both transportation and buildings. Further, as with generation mix projections, it should require regions to plan according to a variety of scenarios. Scenario analysis is particularly appropriate with regard to electrification because, as Brattle analysts observe, "[t]he dynamics of electrification adoption, like the adoption of all new technologies, are likely to be characterized by hard to predict tipping points

67 *See* Stacey Hobart, *Electrification Nation?*, July 29, 2020.

68 *See* *Local Law No. 97 of 2019:* To amend the New York city charter and the administrative code of the city of New York, in relation to the commitment to achieve certain reductions in greenhouse gas emissions by 2050.

69 Sierra Club, *Building Electrification Action Plan for Climate Leaders*, at 7, December 2019.

70 *See* MJB&A, *Toolkit for Advanced Transportation Policies*, October 2018.

71 *See*, e.g., Center for Climate and Energy Solutions, *U.S. State Clean Vehicle Policies and Incentives*, last updated January 2019.

72 Lauren Sommer and Scott Neuman, *California Governor Signs Order Banning Sales Of New Gasoline Cars By 2035*, September 23, 2020.

73 Dr. Jürgen Weiss, J. Michael Hagerty, and María Castañer, *The Coming Electrification of the North American Economy*, at 17, March 2019.

74 *See*, e.g., PJM, *Regional Transmission Expansion Plan*, at 25, February 29, 2020, (describing PJM's load forecasting model).

75 PJM, *Regional Transmission Expansion Plan*, at 37, February 29, 2020.

that result in rapid and widespread changes in consumer preferences and exponential growth once a certain tipping point is reached."[76] For this reason, MISO's methodology, that uses electrification as an overlay to the load forecast included in its Futures assessment, is appropriate, beyond updating the underlying load forecast itself.

3. Plans should incorporate resilience and reliability

The National Commission on Grid Resilience, noting the national security risks and the benefits of large-scale transmission described above, recommended, "Order 1000 ... failed to anticipate the need for inter-regional transmission over larger geographic scales between multiple grid regions in the wake of rising penetrations of renewable energy."[77] The report recommended "We agree with calls for reform, and specifically recommend that FERC strengthen requirements for interregional transmission planning, encourage longer term thinking about the value of larger lines (including high voltage direct current (HVDC) lines) and advanced technologies such as power flow controls and dynamic line ratings, and require RTOs/ISOs to assert leadership in planning processes and represent the public interest in doing so."[78] National security interests and expertise should be included in transmission planning processes.

4. Needs assessments should incorporate information on the use of non-wires options

Order No. 1000 rightly requires regional and inter-regional planning entities to "consider proposed non-transmission alternatives on a comparable basis."[79] Yet, because they are not currently given cost recovery in the transmission planning process, developers of such solutions, which include distributed energy resources such as energy efficiency, demand response, and energy storage, have little incentive to propose these solutions in the planning process. Therefore, the Commission should require regional planning entities to develop methods that assess the extent to which such solutions are likely to be able to cost-effectively reduce or replace the need for transmission solutions, without requiring them to be formally proposed. Such processes may consist of refinements to load forecasting analysis to account for the fact that solutions are more likely to be put forward in pockets with higher value, as well as linkages to state non-transmission solutions planning proceedings.

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76 Dr. Jürgen Weiss, J. Michael Hagerty, and María Castañer, *The Coming Electrification of the North American Economy*, at 6, March 2019.

77 NCGR, *Grid Resilience: Priorities for the Next Administration*, at 42, 2020.

78 *Ibid.*, at 42.

79 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 148, July 21, 2011.

Planning should also assess how strategically sited energy storage or advanced types of demand response deployed as transmission assets, included within state integrated resource plans, or likely to be built via competitive market forces, can serve as a complement to transmission expansion, allowing more efficient utilization of new transmission equipment. This includes benefits from storage charging when downstream transmission is congested and later discharging that energy when it is not, which is particularly advantageous for storage located in wind or solar producing areas. It also includes use of the fast charge and discharge response of storage devices to help accommodate system contingencies, instead of the current approach of leaving transmission capacity unutilized at all times so the system remains stable during flow conditions following a contingency.

5. ***Planning entities should incorporate input from states on siting***

Information from states will be critical to developing reasonable planning scenarios, considering the role states play with regard to the siting and permitting of transmission infrastructure. Reasonable planning scenarios should reflect siting constraints. The timing of the regional transmission planning processes means that the Commission should not reverse its determination in Order No. 1000-A "that it would be an impermissible barrier to entry to require, as part of the qualifica-

tion criteria, that a transmission developer demonstrate that it either has, or can obtain, state approvals necessary to operate in a state, including state public utility status and the right to eminent domain, to be eligible to propose a transmission facility."[80] But the Commission should go beyond Order No. 1000 in seeking ways to incorporate state input on siting and other related issues into the regional and interregional planning processes.

For example, the Commission can require regional planning entities to solicit input from states on siting considerations in advance, so that regional planning processes are designed with an eye toward state siting processes. Where states have broad siting priorities, such as prioritizing construction in existing corridors, that can be taken into account. Where particular projects have already obtained siting approval, or particular corridors have been designated by states, U.S. DOE,[81] or the Bureau of Land Management[82] as ripe for transmission development, regional planning entities can prioritize those projects or locations.

Because states have jurisdiction to set policies that control the mix of resources on the system, they will provide critical input to RTOs and other regional planning entities in constructing grid mix scenarios.

6. Planning scenarios and models should be consistent with operational practice

The scenarios and resulting models developed for planning efforts should reflect plausible and expected system conditions, including the realistic response those conditions would elicit from system operators.

Historically, planning was focused on meeting peak demand, which necessitated most generating resources to be online and dispatched at high levels to meet the peak. With increased renewable generation, many times the most stringent transmission needs occur during periods with lower demand, when there can be significant flexibility to reschedule and redispatch resources, as not all of them are needed to meet demand under those conditions. However, planning models have tended to not account for this flexibility, and instead assume a certain fixed schedule and output of dispatchable thermal generation. These dispatch levels can be inconsistent with how these resources would behave under real system and market conditions in operations. As a result, the transmission system is modeled in planning as more burdened or with less capacity than it would have in operations under those same conditions. Planning models and power flow cases

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80 *Ibid.*, at P 441.

81 *See 16 U.S.C. § 824p.*

82 *See Energy Policy Act of 2005, § 368*, Pub. L. No. 109-58, H.R., August 8, 2005.

should reflect system conditions that are consistent with how the system is operated, including dispatching units using the same least-cost dispatch logic used to dispatch units in operations.

C. Transmission plans should construct the best feasible portfolios based on all available technologies, configurations, and options

Beyond carrying out planning according to reasonable scenarios projecting supply and demand mix, the Commission should also build on Order No. 1000's requirements to ensure that the scenarios modeled draw on all types of solutions to serve transmission needs, and include in plans all types of technologies and configurations.

1. Plans should consider and include all grid enhancing technologies

As a number of parties commented in the Commission's Notice of Proposed Rulemaking on transmission incentives, Grid Enhancing Technologies (GETs) should be included in the transmission planning process.[83] Dynamic Line Ratings, power flow control, topology optimization, and storage as transmission are "transmission assets," which can be directly included in plans, with costs recovered in RTO tariffs just like other transmission technologies. The American Public Power Association explains that regional processes for identifying solutions should "identify efficient and cost-effective GETs deployments (e.g., by ascertaining transmission paths with severe congestion that GETs might alleviate at a lower cost than alternatives)."[84] GETs should be modeled consistent with how they would be operated to deliver both reliability and economic benefits. These technologies often provide a great deal of flexibility that may be useful in a variety of potential system conditions. GETs are also generally modular (can be sized to the need) and mobile (can be physically moved to different points on the grid), which provides option value to any facility acquired.[85] These forms of optionality value should be incorporated into benefits assessments.

83 *See*, e.g., *Comments of Transmission Access Policy Study Group*, Docket No. RM20-10, at 8-9, July 1, 2020 ("While the NOPR rightly does not propose the highly problematic shared-savings incentives, its proposed incentives for deployment of transmission technologies needlessly increase cost without addressing the real obstacles to deploying new technologies. A better approach would be to integrate advanced technologies into Order 890 and Order 1000 processes."); *Comments of Alliance Energy Corporate Services, Inc. and DTE Electric Company*, Docket No. RM20-10, at 35, July 1, 2020 ("The Commission should ensure that required transmission planning processes appropriately consider new technologies and alternative, non-transmission solutions.").

84 *Comments of the American Public Power Association*, Docket No. RM20-10, at 65, July 1, 2020.

85 Kerinia Cusick, Jon Wellinghoff, and Lorenzo Kristov, *Transmission Planning Protocol: Leveraging Technology to Optimize Existing Infrastructure*, August 2019.

Because the impacts of GETs are sometimes easier to measure in the shorter-term time frame (months to hours) rather than years, the Commission should consider whether an incremental step in the planning process may be appropriate that is particularly targeted at measuring ways in which GETs could improve operations of the existing system. At the same time, the inclusion of GETs in the long-term solution mix may frequently yield benefits, and may be used in conjunction with new infrastructure improvements to offer a more efficient solution than would otherwise be provided.

2. *Plans should consider options of non-traditional physical assets and configurations*

Future needs will likely call for more long-distance transfers of power across time zones and areas with asynchronous loads shapes. That factor along with the falling costs of High Voltage Direct Current (HVDC) will likely lead to more applications of HVDC into plans. Regional planners have not utilized HVDC much in recent decades, and it raises issues about control and operation that are different from current systems. Planners should address these opportunities and changes that may be needed.

New types of conductors, converters, transformers, and other assets provide potential reliability, resilience, and efficiency benefits that should be considered in transmission plans. For example, HVDC lines with Voltage Source Converters present opportunities for black starting whole regions with power from neighboring regions. Composite core transmission lines can deliver more and withstand more severe weather events than traditional conductors. All such options should be considered and incorporated as appropriate.

3. *Benefits of individual and merchant lines should be assessed in regional and inter-regional planning, whether or not they are not cost allocated*

Order No. 1000 does not require merchant transmission developers to participate in regional planning processes because they do not receive regional cost allocation.[86] It does, however, require merchant developers "to provide adequate information and data to allow public utility transmission providers in the transmission planning region to assess the potential reliability and operational impacts of the merchant transmission developer's proposed transmission facilities on other systems in the region," and allows merchant transmission developers to voluntarily participate in the regional transmission planning

86 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 163, July 21, 2011.

process.[87]

Assessing the benefits of merchant transmission development in regional transmission plans is appropriate because, even though such infrastructure does not receive regional cost allocation, it impacts the overall mix of solutions that may be built. Further, assessing the benefits and costs of merchant transmission solutions could help these projects secure state-level siting permits, by demonstrating the need for these projects. For this reason, the Commission should build on Order No. 1000's requirement for merchant developers to provide data to inform the regional transmission planning process[88] by directing planning entities to conduct planning scenarios that quantify the benefits of merchant projects. In addition to helping inform regional processes, this would help merchant developers drive projects forward by giving them some evidence of need that they could use in state permitting processes. Similarly, cost allocated lines that are assessed through portfolio benefits assessments should be studied for individual benefits upon request, for use in permitting proceedings.

D. FERC should direct planning entities to select infrastructure for inclusion in regional plans by maximizing net benefits of a portfolio

Once needs are assessed based on best available information, all benefits are considered together, and all technology and configuration options are considered, regional planning entities should be directed to select plans that maximize the net benefits of a portfolio of transmission investments.

The Commission should build on Order No. 1000 to provide greater direction and clarity about the wide range of benefit metrics regional planning entities should use to assess whether solutions are beneficial and should thus be included in the regional plan, directing planning entities to achieve just and reasonable rates by using Benefit-Cost Analysis (BCA). There will be many trade-offs between different options. Some investment options will be more costly in the near-term but carry much greater benefits over the long term. Some will be extremely low cost and fast to deploy with benefits that well exceed their costs, even though those benefits may not be as great as long-term large-scale options. In some cases, the options will be mutually exclusive and in other cases they will be complementary such that they could be done together. BCA provides a clear planning protocol that prioritizes among these potentially competing or complementary invest-

87 *Ibid.*, at PP 164-165.

88 *Ibid.*, at PP 163-165.

ments based on what would be most likely to result in just, reasonable, and not unduly discriminatory rates.[89]

1. ***Pro-active holistic transmission planning to maximize net benefits is fully compatible with standard RTO market designs and competitive generation markets***

The six FERC-jurisdictional RTOs (ISO-NE, NYISO, PJM, MISO, SPP, and CAISO) as well as the ERCOT all use a form of bid-based security constrained economic dispatch with locational prices and financial transmission rights. The academic literature behind locational marginal price (LMP) design does not make the claim that the efficient level of transmission is achieved by relying only on voluntary investment. To the contrary, the leading economists and engineers were clear that planned investment is required to achieve efficiency. As perhaps the leading international expert and proponent of the LMP design, Dr. William Hogan of Harvard University, wrote recently:

> If there were no economies of scale and scope for transmission investment, electricity markets could follow the same competitive model for transmission where beneficiaries determine and pay for their own investments. Given the large economies of scale and scope, transmission is a natural monopoly and investment requires a central coordinator.[90]

Dr. Hogan explains the appropriate decision rule for transmission planning is Benefit-Cost Analysis: "A forward-looking cost-benefit analysis provides the gold standard for ensuring that transmission investments are efficient."[91] He continues to explain BCA as the only reasonable option for efficient grid planning:

> There is no other way of determining whether a grid investment is efficient. Whatever the purpose of the grid investment, it will only be efficient if the benefits it provides — for example, in terms of lower energy production costs or increased reliability — exceed the cost of the investment. No investment should proceed without being subject to a cost-benefit assessment which quantifies all benefits and costs.[92]

Some parties may prefer to rely only on voluntary investment and Financial Transmission Rights as the incentive for such investment, and some market participants would

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89 *See* generally Avi Zevin, *Regulating the Energy Transition: FERC and Cost-Benefit Analysis*, May 2020 (arguing that greater use of cost-benefit analysis will further the Commission's mission of cost-effectively serving customers).

90 William W. Hogan, *Transmission Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal*, at 1, February 1, 2020.

91 *Ibid.*

92 *Ibid.*, at 5.

probably fare better in that model. However, that is not efficient for consumers as Dr. Hogan's paper thoroughly describes. Relying only on voluntary investment by market participants does not work in theory because public goods are always under-provided when relying only on voluntary market participant investments. It does not work in practice either, as we have seen persistent congestion and a lack of infrastructure development as described in the first section.

Similarly Dr. Paul Joskow, the economist who initiated the movement towards competitive generation markets perhaps more than any other economist with his 1983 book Markets for Power,[93] has long recognized the natural monopoly and public goods aspects of transmission that do not lend themselves to a competitive structure for that sector. Instead he advocates for pro-active broad regional planning to achieve the efficient transmission network: "Barriers to expanding the needed inter-regional and internetwork transmission capacity are being addressed either too slowly or not at all."[94] During restructuring he advised the Commission:

> There are numerous reasons why we should not expect "the market" to produce transmission enhancements that meet reasonable economic and reliability goals. *Indeed, proceeding under the assumption that, at the present time, "the market" will provide needed transmission network enhancements is the road to ruin*. There is abundant evidence that market forces are drawing tens of thousands of megawatts *of new generating capacity* into the system. There is no evidence that market forces are drawing significant quantities of entrepreneurial investments in new transmission capacity. While third parties should be given the opportunity to propose market-based private initiatives to expand transmission capacity, incumbent transmission owners, in the context of a sound RTO/ISO planning process, must be relied upon to play a central role in expanding the transmission system.[95]

The arguments above from leading economists apply both to RTO structures as well as to transmission outside of RTO where traditional "contract path" transmission service is utilized. In either case, just and reasonable rates are also best achieved by pro-active holistic planning that maximizes net benefits.

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93 Paul L. Joskow and Richard Schmalensee, *Markets for Power*, MIT Press, November 1983.

94 Paul Joskow, *Transmission Capacity Expansion is Needed to Decarbonize the Electricity Sector Efficiently*, Joule 4, at 1-3, January 15, 2020.

95 *Comments of Professor Paul L. Joskow*, Docket RM 99-2, at v, August 16, 1999.

2. The Commission should direct planning entities to apply standard methods of incorporating uncertainty into BCA

BCA analysis of transmission portfolios will be shaped by the planning process, as the core of the analysis will be a forward-looking projection of benefits and costs across the scenarios examined. As recommended above, the Commission can ensure a wide range of benefits are accurately assessed by requiring incorporation of all factors likely to shape the future demand and supply mix, mandating consideration of all relevant technologies.

BCA can and should handle uncertainties, of which there are many in transmission. Fuel prices, load growth, load shapes, generation mix, and weather patterns can all change and lead to differing results on which transmission has benefits that exceed costs. Public policies may be expressed via actions such as Executive Orders that do not have the full force of statutes or regulations yet may nevertheless be likely to guide the transmission mix. Standard BCA uses the concept of "expected value" to address uncertainty. Expected value arrives at a single expected benefit number when considering two scenarios by multiplying the probability of the scenario times the value of it.

Certain scenarios significantly influence the expected value of transmission. For example, transmission enables existing power plants to be dispatched in real-time as fuel prices fluctuate or demand shifts. The value of transmission can be particularly high during extreme events, especially where they cause fuel prices and demand to spike while suppressing supply in localized region, making imports from other regions extremely valu-

able. For example, additional transmission would likely have yielded hundreds of millions of dollars in savings over a matter of days during recent Polar Vortex and Bomb Cyclone events.[96] Probabilistic transmission analysis will also become increasingly valuable as the penetration of variable renewable resources increases, which can make transmission ties extremely valuable during periods of regional renewable over-supply or shortage.

Transmission also creates optionality for new power plants to be built to take advantage of unexpected shifts in the economics of different energy sources. Over the last decade, transmission has not only allowed customers to benefit from the large cost reductions for wind and solar generation, but also the increased availability of low-cost shale natural gas in many regions where gas resources were not previously available. Because it takes much longer to plan, permit, and build transmission than generation, it is often not possible to wait for economic and policy shifts to occur before investing in the transmission needed to optimally respond to them.

SPP and Brattle Group analysts have documented the value of transmission for providing optionality to hedge against uncertainty in future fuel prices, the generation mix, and other factors.[97] Additional analysis has shown the optionality value of transmission to be very large and found that standard transmission planning methods greatly underestimates the value of transmission.

Plans that ignore important scenarios will produce inefficient outcomes. Analysis by Dr. Ben Hobbs and Francisco Espinoza from Johns Hopkins University shows that current transmission planning methods, which at best use several deterministic scenarios to highlight ranges of future outcomes for the power system, are "a weak tool for decisions under uncertainty" and "don't account for flexibility."[98] Relative to standard deterministic methods that do not account for uncertainty, probabilistic transmission planning methods that account for uncertainty by simultaneously evaluating a large number of possible scenarios result in both a larger and more optimal transmission build, potentially saving consumers tens or even hundreds of billions of dollars.[99]

Other recent analysis found that the consumer savings from use of such probabilistic (stochastic) tools in the Western U.S. "can be as much as or even exceed the cost of the

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96 Michael Goggin, *How Transmission Helped Keep the Lights on During the Polar Vortex*, February 14, 2019.

97 Johannes Pfeifenberger and Judy Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon Constrained Future*, June 2016; and SPP, *The Value of Transmission*, January 26, 2016.

98 Francisco D. Munoz, Jean-Paul Watson, and Benjamin F. Hobbs, *Optimizing Your Options: Extracting the Full Economic Value of Transmission When Planning Under Uncertainty*, The Electricity Journal, Volume 28, Issue 5, at 26-38, June 2015; and Benjamin F. Hobbs, Francisco D. Munoz, Saamrat Kasina, and Jonathan Ho, *Assessing Transmission Investments under Uncertainty*, August 2013.

99 Francisco David Muñoz Espinoza, *Engineering-Economic Methods for Power Transmission Planning Under Uncertainty and Renewable Resource Policies*, at 102, January 2014.

recommended transmission facilities themselves."[100] The analysis "provide[s] evidence that the transmission recommendations of stochastic programming models are more robust to scenarios that haven't been considered than recommendations by deterministic models. That is, stochastic plans appear to make the network more adaptable in the face of all uncertainties, not just those that were included as specific scenarios."[101]

Transmission planning analysis often identifies certain scenarios where the value of transmission is extremely high even if it is not in the base case. But while many planning entities currently assess projects across a range of scenarios, they do not generally assign probabilities to these scenarios or clarify how the different scenario results factor into project selection. For the reasons above, BCA applied to transmission should consider scenarios and probabilities to arrive at expected value of transmission.

3. *The Commission should provide a minimum set of benefits that must be included in any BCA analysis conducted by planning entities*

Beyond ensuring that BCA is performed according to the reasonable likelihood of future scenarios, the Commission should also set a minimum standard for quantifying benefits and encourage planners to innovate and learn from one another's experience in quantifying benefits.

While many planning entities currently perform BCA analysis, none fully quantify the full range of benefits provided.[102] For example, SPP's benefit-cost methodology excludes transmission's benefits in lowering reliability margins, improving grid resilience to extreme weather, enabling more efficient operating practices and maintenance schedules, and enabling future markets.[103] To remedy these failures to accurately quantify benefits and provide a more consistent standard for judging projects, the Commission should mandate a minimum set of standards for quantifying benefits.

BCA should simultaneously evaluate all categories of benefits provided by transmission, instead of the siloed approach currently used in many regions. It should also include benefits that are not currently quantified in most regional transmission planning processes,

100 Jonathan L. Ho et al., *Planning Transmission for Uncertainty: Applications and Lessons for the Western Interconnection*, January 2016.

101 *Ibid*.

102 *See,* e.g., Burcin Unel, *A Path Forward for the Federal Energy Regulatory Commission: Near-Term Steps to Address Climate Change*, at 14-15, September 2020.

103 *See* Johannes Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*, at 12, November 6, 2019, (citing SPP, *Priority Projects Phase II Report*, February 2010, and SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July 5, 2012).

but for which quantification methods exist.[104] As shown in the following table from SPP's report on the topic, transmission provides many benefits, though many are typically not quantified (listed as "N/Q"). BCA determines which options are efficient to pursue, taking all factors into account, and ensures that options that do not reduce rates in the long term are not chosen.

104 For example, *see* Judy W. Chang, Johannes P. Pfeifenberger, and J. Michael Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, Appendix A, July 2013; and Judy W. Chang et al., *Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process*, Appendix B, October 2013.

TABLE 1 **Projected Net Present Value (NPV) of SPP Transmission Projects Installed in 2012-14, Based on the First Year of SPP's Integrated Marketplace (Mar 2014 - Feb 2015)**[105]

BENEFIT CATEGORY	TRANSMISSION BENEFIT	NPV ($M)
Adjusted Production Cost Savings	Reduced production costs due to lower unit commitment, economic dispatch, and economically efficient transactions with neighboring systems	10,442*
1. Additional Production Cost Savings **	a. Impact of generation outages and A/S unit designations	INCLUDED
	b. Reduced transmission energy losses	INCLUDED
	c. Reduced congestion due to transmission outages	INCLUDED
	d. Mitigation of extreme events and system contingencies	PARTIAL
	e. Mitigation of weather and load uncertainty	PARTIAL
	f. Reduced cost due to imperfect foresight of real-time system conditions	INCLUDED
	g. Reduced cost of cycling power plants	PARTIAL
	h. Reduced amounts and costs of operating reserves and other ancillary services	PARTIAL
	i. Mitigation of reliability-must-run (RMR) conditions	N/Q
	j. More realistic "Day 1" market representation	N/Q
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects	105
	b. Reduced loss of load probability or c. reduced planning reserve margin (2% assumed)	1,354
	c. Mandated reliability projects	2,166
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses	171
	b. Deferred generation capacity investments	N/Q
	c. Access to lower-cost generation resources	PARTIAL
4. Market Benefits	a. increased competition	N/Q
	b. Increased market liquidity	N/Q
5. Other Benefits	a. storm hardening	N/Q
	b. fuel diversity	N/Q
	c. flexibility	N/Q
	d. reducing the costs of future transmission needs	N/Q
	e. wheeling revenues	1,133
	f. HVDC operational benefits	N /A
6. Environmental Benefits	a. Reduced emissions of air pollutants	N/Q
	b. Improved utilization of transmission corridors	
7. Public Policy Benefits	a. Optimal wind development	1,283
8. Employment and Economic Development Benefits	b. Other benefits of meeting public policy goals	N/Q
	Increased employment and economic activity; Increased tax revenues	N/Q
	TOTAL	**16,670 +**

105 SPP, *The Value of Transmission*, Appendix B, January 26, 2016.

To address these gaps, and similar gaps in other planning regions, the Commission should require all planning entities to at least:

- Fully capture production cost savings, including many categories in traditional analyses (reduced transmission energy losses, reduced congestion due to transmission outages, reduced cost of cycling power plants, etc.);[106]
- Consider the extent to which the transmission project can avoid the need to replace aging facilities in the future, as NYISO did in its assessment of a recently approved public policy project;[107] and
- Fully capture the reliability value of transmission infrastructure, including (i) avoided/deferred reliability projects, (ii) reduced expected unserved energy or reduced planning reserve margin, (iii) reduced capacity needs from reduced losses at times when the grid is stressed, (iv) enabling market access to less costly capacity resources, (v), improved reserves sharing, and (vi) increased voltage support.

Because methodologies for assessing benefits are likely to improve over time, criteria adopted by the Commission should establish a floor, but not a ceiling for benefits to be considered.

4. BCA should include reliability and resilience factors

BCA can handle "reliability" and "resilience" factors as well as production costs and more measurable economic factors. Of course, transmission that is strictly required for compliance with reliability standards will be incorporated into plans. Beyond what is required, however, are reliability and resilience benefits associated with any given transmission investment option. Reliability and resilience values can be quantified, measured, and monetized.[108] It will matter, for example, whether a scenario results in 1% of load being shed for a short period of time versus all load for an extended period. Therefore "loss of load probability" (percent chance of load loss) will be less useful than "expected unserved energy" (expected MWhs of load lost). BCA using expected values can take into account real-world instances like what we have recently witnessed with cold snap conditions and generator outages leading to maximum possible transfers of power from one region to

106 The Brattle Group report provides a set of best practices on benefits to include in analyses, as well as an overview describing how different RTOs capture different benefits, but all leave certain benefit categories out of their analysis. *See* Johannes Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*, at 12-13, November 6, 2019.

107 *See* NYISO, *AC Transmission Public Policy Transmission Plan*, at 3, April 8, 2019, (assessing "quantitative and qualitative metrics include the project's capital cost, cost per MW, expandability, operability, performance, property rights and routing, schedule, metrics identified by the NYPSC (e.g., replacement of aging infrastructure), and other metrics (e.g., production cost savings, Location Based Marginal Pricing ("LBMP") savings, Installed Capacity ("ICAP") savings, and emissions savings").

108 *See* Burcin Unel and Avi Zevin, *Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System*, August 1, 2018.

the next. Even if that is expected to happen a few times over the life of a transmission investment, it can justify the investment. Planners can quantify expected value using the principle of expected loss of load (LOLE) times value of lost load (VOLL), as with the treatment of uncertainty described above. But as explained further below, there is no legal requirement to fully quantify all or most components of benefits. The economic principle can be followed regardless of how much quantification is performed, as the best way to achieve just and reasonable rates.

5. BCA should incorporate social benefits if public policies include them

Where applicable, regional planning entities should also include societal benefits as reflected by public policies. For example, the New York System Operator already applies a "Social Cost of Carbon" sensitivity to its analyses of public policy projects,[109] reflecting New York State's public policies that place a negative value on carbon emissions.[110] The Commission should require planning entities to build this approach wherever the applicable public policymakers have put a value on emissions, using that value as the base case for all planning scenarios across applicable market nodes, rather than using it merely as a sensitivity and only for public policy projects.[111] To the extent that different public policy requirements are in place across a region, planning entities can apply different values at different market nodes.

6. BCA time frames should reflect the full life of the transmission assets

Standard BCA is performed over the life of assets. This is intuitive to traditional transmission planners. For example, the Pacific direct current (DC) Intertie is a key part of the Western power system 50 years after its dedication.[112] It is obvious that if today's common approach of assessing benefits over 10 to 15 years were applied, such important infrastructure would never have been built. The Commission should direct planning entities to assess benefits across the full useful life of transmission infrastructure, which is generally over 40 years.[113] Despite transmission's long asset life, regional planning entities often carry out benefit-cost analysis using a much shorter forecast period. Because the benefits tend to grow over time (often faster than the relevant discount rate) but regulated

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109 *See*, e.g., NYISO, *AC Transmission Public Policy Transmission Plan*, at 20-22, April 8, 2019.

110 For example, the New York Public Service Commission's Benefit-cost Analysis framework factors in the social cost of carbon. *See Order Establishing the Benefit Cost Analysis Framework*, Case 14-M-0101, January 21, 2016.

111 Where incorporating quantified social benefits is not supported by the relevant public policies, it is nevertheless critical that supply, demand, and congestion created by those policies factor into other components of the benefits analysis.

112 Bonneville Power Administration, *Direct current line still hot after 40 years*, May 26, 2010.

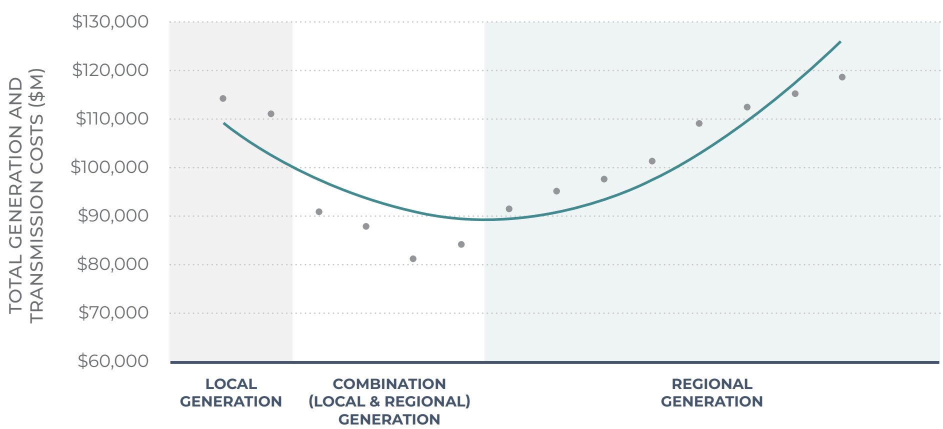
113 Union of Concerned Scientists, *Average Life Expectancy of Select Infrastructure Types and Potential Climate-Related Vulnerabilities*, n.d.

cost of transmission declines over time as assets are depreciated, BCA horizons that do not cover the life of the asset will understate benefit-to-cost ratios. For example, PJM's market efficiency planning process assesses benefits across only a 15-year planning period.[114]

7. BCA should include the trade-off the consumer benefits of local vs remote resources

In selecting projects to maximize net benefits, the Commission should direct planning entities to co-optimize transmission investments with generation expansion planning, particularly renewable resources needed to meet public policy requirements, to minimize the total cost of generation plus transmission. This was the cornerstone of MISO's approach in its Regional Generation Outlet Study and Multi-Value Projects (MVP) analysis, as shown in the MISO chart below.[115]

FIGURE 13 **MISO "Bathtub" Curve of Optimal Local vs Remote/Regional Generation**



8. BCA Assessments should include full portfolios

Consistent with the recommendation above of incorporating multiple benefits together, BCA should be performed on the full portfolio of transmission projects. Assessing the full portfolio accounts for instances where some options will be mutually exclusive and others will be additive—the latter will show up with greater benefits than the former as it should. BCA on the portfolio will also account for trade-offs between smaller speedier

114 *See* PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, Attachment E at 108, October 1, 2020.

115 MISO, *MTEP17 MVP Triennial Review*, at 31, September 2017.

technology and grid operations investments versus larger longer-term options. If each transmission line or investment were assessed separately, these interactions would be ignored and net benefits would be misleading. Assessing the benefit of a portfolio of transmission assets will also facilitate cost allocation as discussed further below.

9. BCA assessments should not only be quantitative

While the Commission should require a robust approach to quantifying transmission benefits, not all benefits and costs can be quantified or boiled down to a dollar figure. Some pros and cons that may be attributed to different options will be inherently subjective. While the common metrics described above will be useful when comparing various options, and can provide clearer guidance and an objective recipe for decision-making, they cannot possibly address all of the relevant considerations that should be weighed in transmission planning, so regional entities will require some flexibility to prioritize certain projects over others due to qualitative criteria. "The sensible way to deal with uncertainty about some aspects of a benefit or a cost is to quantify what can be quantified, to array and rank nonquantifiable factors, and to proceed as far as possible."[116]

Legal requirements do not require full quantification. Where the rubber meets the road in assigning costs to beneficiaries, as described in Section IV of this report, the legal standard is that the assignment be "roughly commensurate" with beneficiaries, not that every electron be assigned to every individual customer. At the upstream planning stage of the process, before we reach the cost allocation stage, that same "roughly commensurate" standard can be applied. What is important is the conceptual framework of maximizing net benefits of a portfolio.

10. Resource diversity value and the value of transmission to mitigate operational uncertainty can and should be quantified in the benefits assessment

An increasing set of benefits have been quantified, and can and should be quantified and incorporated into benefits assessments. Recently a study was issued by the Boston University Institute for Sustainable Energy quantifying the benefits of transmission from connecting wind energy from different wind regions, given the uncertainties of wind output in the day ahead time frame.[117] Since the correlation of wind output decreases significantly with distance, there is a steadier supply of zero variable cost energy when

116 Edward M. Gramlich, *A Guide to Benefit-Cost Analysis,* 2nd edition, at 5, Waveland Press, 1988.

117 Kai Van Horn, Pablo Ruiz, and Johannes Pfeifenberger, *The Value of Diversifying Uncertain Renewable Generation Through the Transmission System*, October 2020.

different wind sites are connected to each other, reducing system dispatch costs.

11. The BCA decision rule should be to maximize net benefits

The Commission should require planning entities to adopt a general objective of maximizing net benefits from the various portfolio options considered. Maximizing net benefits accounts for the differing scales of different options. For example, a set of larger more expensive lines will have much higher costs but potentially much larger benefits than a smaller cheaper portfolio. Maximizing net benefits leads to the greatest benefits to consumers over the long run. Maximizing net benefits is more appropriate than a benefit-cost ratio because, as in the example above, a high ratio could yield lower net benefits to consumers. "The last step is reasonably clear…find the program that maximizes net benefits…do not even get tempted to show benefit-cost ratios — they can just get you into trouble."[118] Once again, full quantification is not required. What is important is the conceptual framework.

Order No. 1000 provides that where regional planning entities use a benefit-cost analysis threshold to evaluate projects, "such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a greater ratio."[119] In accordance with this rule, many regional planning entities rely upon benefit-cost thresholds of 1.25. This approach, by its nature, will deny projects the opportunity to proceed even where they would provide net benefits. This is exacerbated by the fact that many difficult-to-quantify benefits of transmission may not be quantified. Thus, a project may yield significant net benefits even where its official BCA score is 1 or lower. Of course, when maximizing net benefits, the BCA ratio for any portfolio that performs better than a no-investment option will necessarily exceed 1.0, so a BCA ratio of 1.0 can also be a guideline but is not separately needed as a standard.

E. Planning methods should be made compatible across regions to enable inter-regional transmission

While Order No. 1000 attempted to address inter-regional coordination and planning, designing and implementing projects to address needs across transmission planning re-

118 Edward M. Gramlich, *A Guide to Benefit-Cost Analysis,* 2nd edition, at 230, Waveland Press, 1988.

119 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 586, July 21, 2011.

gions remains extremely challenging. No significant inter-regional transmission project has been approved. This lack of approval of any significant inter-regional projects under Order No. 1000 combined with studies finding that such projects would yield significant consumer benefits if built,[120] demonstrate need for inter-regional planning reform.

Inter-regional projects face a "triple hurdle" in that they must not only be selected via the inter-regional process, but also must gain approval from each respective RTO. This "triple hurdle" is the heart of the challenge in inter-regional planning. To address this barrier, the Commission should at a minimum require compatible benefits metrics, and study approaches between neighboring regions in approving interregional projects, and mandate that these metrics seek to maximize net benefits on an inter-regional, not regional basis. As part of this exercise in aligning the regional planning processes, the Commission should require all regions to treat inter-regional projects as multi-value projects, rather than placing them in siloes according to the benefits they create (which creates a risk that the siloes used for a given project by each region will not match). Aligning regional approval processes in this manner would help to address the challenge inter-regional projects face in being subject to different metrics and approval standards in the different RTOs from which they must obtain approval.

SPP and MISO have recently attempted to address the barrier of unaligned regional processes by seeking to limit the extent to which the coordinated interregional process must rely upon a single model, recognizing neighboring RTOs have different assumptions underlying their transmission planning processes, and a single model cannot possibly match the assumptions used by both RTOs.[121] The Commission approved SPP's and MISO's proposal to eliminate the use of a single regional model,[122] and the regions have now announced a new joint study which will focus on better and collaborative plans to address generation interconnection needs initially,[123] which presumably will be able to be fed through different modeling assumptions in each region. But while this may facilitate more review of inter-regional projects between SPP and MISO by each respective RTO board without excluding benefits due to a mismatch of approach between regions, a more direct approach is to ensure that the RTO planning methods are aligned such that a unified model can be compatible with each region's evaluation framework.

120 Scott Madden projects, based on enacted clean energy standards and corporate and utility clean energy procurement policies, that "many regions are projected to have adequate or excess renewable supply compared with 'headline' clean energy demand," whereas other regions, including California, New York, and New England, will have a need for additional supply which could be served by import from other regions. Scott Madden, *Informing the Transmission Discussion: A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States*, at 17, January 2020.

121 *Midcontinent Independent System Operator, Inc., Southwest Power Pool, Inc.*, 168 FERC ¶ 61,018, at P 7, July 16, 2019.

122 *Ibid.*, at P 41.

123 SPP, *MISO and SPP to Conduct Joint Study Targeting Interconnection Challenges*, September 14, 2020.

Adopting the minimum guidelines for planning and benefit-cost analysis we have recommended in this section for all regions will make it easier for regions to find alignment in inter-regional project evaluation processes. Beyond establishing this minimum set of guidelines, the Commission should also enable and encourage regions to incorporate additional benefits including in neighboring regional methodologies, as well as incorporate additional benefits that may be unique to interregional projects.[124] As Brattle Group analysts recommend, each seams entity should be given "the option, but not the obligation, to consider some or all of the benefits and metrics used by the other seams entity even if these benefits and metrics are not currently used in the entity's internal transmission planning process."[125] Further, seams entities may "agree to develop metrics to capture any [unique] seams-related benefits."[126]

Regions can update their planning processes with an eye toward inter-regional compatibility such that the primary changes they need to make that are particular to inter-regional review relate to evaluating such projects by maximizing inter-regional benefits as opposed to maximizing benefits solely within the region's borders. The Commission should require the method established to provide that all projects capable of providing net benefits are eligible for inclusion in an interregional plan, disallowing exclusions for projects of arbitrary voltage levels or sizes that currently exist in some interregional planning processes. Interregional planning processes should be conducted at annual intervals, and include a process for ensuring that projects included in the plans are not duplicative of projects being approved within regional planning processes.

124 *See* Johannes P. Pfeifenberger and Delphine Hou, *Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning*, at 53, April 2012 (recommending a set of principles for quantifying benefits of seams projects).

125 *Ibid.*

126 *Ibid.*

IV. Cost allocation

As the Commission recognized in Order Nos. 890 and 1000, “knowing how the costs of transmission facilities [will] be allocated is critical to the development of new infrastructure because transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs.”[127] The Commission made significant progress in clarifying cost allocation issues in Order No. 1000, requiring public utility transmission providers to establish regional and interregional cost allocation methodologies that meet a set of six principles established by the Commission, but allowing cost allocation methodologies to vary by project type.[128] Very different approaches to regional cost allocation have been deployed in compliance with Order No. 1000, and several have evolved with time to align beneficiaries and cost assignments. Others, such as MISO-planned reliability projects, have moved away from regional cost allocation to avoid competitive processes.[129] And the generator interconnection process marches to a different drummer altogether, using “participant funding;” these differences should be remedied.

With a few limited exceptions described further below, the Commission should continue to use beneficiary pays principles for cost allocation, as they appropriately straddle the need to provide clarity to stakeholders, while at the same time providing planning entities with flexibility to develop methodologies supported by a broad range of stakeholders given region-specific circumstances that affect the distribution of benefits for regional transmission projects. The Commission can facilitate more cost-effective transmission development by refining the application of its cost allocation principles, while adhering to the same general framework it has already applied. Any changes should be applied prospectively only, and not undermine previous cost allocation agreements on operating or approved projects.

127 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 496, July 21, 2011. (citing Order No. 890, at P 557).

128 *Ibid*., at PP 558-750.

129 Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 20, April 2019

A. The Commission should continue to require that costs of regional and interregional transmission projects be allocated in a manner roughly commensurate with their benefits

The cornerstone of cost allocation should continue to be that public utility transmission providers must provide for processes by which costs are allocated fairly — in a way that is at least roughly commensurate with the benefits. This standard is the first principle articulated by the Commission in Order No. 1000,[130] is well-supported by economic theory,[131] and has also been required by the courts. As the U.S. Court of Appeals for the Seventh Circuit articulated in *Illinois Commerce Commission v. FERC*, to approve a cost allocation methodology, the Commission must have "an articulable and plausible reason to believe that the benefits are at least roughly commensurate" with how the costs are allocated.[132] This principle dictates not only that the Commission may not approve regionally allocated costs without reasons to believe benefits are allocated regionally, but also that it may not approve cost recovery only from local customers where benefits are regional.[133] The Commission should continue to adhere to this approach, which provides flexibility to planning entities and fulfills the Commission's duty under the Federal Power Act to ensure just and reasonable and not unduly discriminatory rates.

While Order No. 1000 declined to prescribe "a particular definition of 'benefits' or 'beneficiaries,'"[134] we recommend that the Commission provide a minimum standard for a broad set of benefits to be included within benefit-cost analysis, as discussed in Section III.D of this paper. Importantly, we recommend a robust benefit-cost methodology that includes what used to be considered "difficult to quantify" benefits. While planners can use benefit-cost analyses to help allocate costs, as described below, the ability to allocate a particular benefit must not be used as a constraint to reduce the scope of benefit-cost assessment. "Benefits that can be allocated readily or accurately tend to be only a subset of readily-quantifiable benefits," so "[r]elying on allocated benefits to assess individual projects would result in rejection of many desirable projects."[135]

Beneficiary-pays principles can be implemented using benefit-cost analysis, despite the challenge of tracing all benefits to beneficiaries. William Hogan explains that where "to-

130 *See* Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities, Order No. 1000, 136 FERC ¶ 61,051, at PP 622-629, July 21, 2011.

131 *See*, e.g., William W. Hogan, *A Primer on Transmission Benefits and Cost Allocation*, Economics of Energy & Environmental Policy, Volume 7, Issue 1, March 2018.

132 *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009).

133 *See Old Dominion Electric Coop. v. FERC*, 898 F.3d 1254, 1261 (2018).

134 *See Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 624, July 21, 2011.

135 *Ibid.*

tal quantifiable benefits exceed the transmission investment cost, then allocating in proportion to the quantifiable benefits would be consistent with efficient investments."[136] And where "easily quantifiable benefits are less than the investment cost, but the subjective estimate is that total benefits are greater . . . a simple rule would be to allocate the costs equal to and according to the quantifiable benefits . . . and then allocate the residual costs . . . according to the regulator's subjective distribution of benefits," which may be distributed evenly across the region, for example.[137] Similarly, Brattle Group analysts explain that a 2-step approach can be used that first determines whether projects are beneficial overall, and next evaluates "how the cost of a portfolio of beneficial projects should be allocated based on distribution of benefits."[138] In this manner, benefit-cost analyses used to guide planning decisions will not be artificially constrained to benefits that can easily be allocated, but will nevertheless serve as the core input to cost allocation decisions.

To provide certainty to market participants, costs should continue to be allocated based on ex ante analysis.[139] Allocating costs to beneficiaries, when the benefits can be measured and beneficiaries can be identified, improves economic efficiency. Transmission is sometimes a complement to other resources and sometimes a substitute. When generation, demand response, or storage closer to load is more economic than transmission, then it should not be discouraged by fully socialized transmission cost allocation without any attempt to determine beneficiaries.[140] Argentina used a governance model of stakeholder support levels to find appropriate cost allocation alignment, which could be a model.[141] State involvement will be important as representatives of load interests.

At the same time, the Commission should retain a degree of flexibility with regard to how costs are allocated. The legal standard under the Federal Power Act does not require a

136 William W. Hogan, *A Primer on Transmission Benefits and Cost Allocation*, Economics of Energy & Environmental Policy, Volume 7, Issue 1, at 39, March 2018.

137 *Ibid*.

138 Johannes Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*, at 28, November 6, 2019.

139 *See Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 499, July 21, 2011 (finding "that the lack of clear ex ante cost allocation methods" prior to Order No. 1000's enactment "may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective solutions); William W. Hogan, *Transmission Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal*, at 4, February 1, 2020 ("A cost-benefit evaluation should be done before the investment decision.").

140 William W. Hogan, *A Primer on Transmission Benefits and Cost Allocation*, Economics of Energy & Environmental Policy, Volume 7, Issue 1, at 39, March 2018.

141 Stephen C. Littlechild, and Carlos J. Skerk, *Transmission Expansion in Argentina 2: The Fourth Line Revisited*, Energy Economics, 30(4), at 1385–1419, July 2008.

precise tracing of benefits to costs,[142] and the Commission should clarify in a new planning rule that even though benefits may be quantified via benefit-cost analysis, they need not be precisely traced to beneficiaries in cost allocation. There are good reasons to refrain from an overly prescriptive approach.

For example, regions may provide for methodologies that do not precisely quantify all benefits so as to provide for greater administrative simplicity. There is a trade-off between relying on analysis to identify the beneficiaries of projects (which inherently cannot be done until a particular project or set of projects have been proposed and evaluated by the relevant planning entity), and setting rules that provide a high degree of clarity at the outset as to how costs will be allocated. As the Commission found in Order No. 1000, "the lack of clear ex ante cost allocation methods that identify beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified during the transmission planning process."[143]

Methods such as postage stamp cost allocation (allocating costs equally to all customers in a region) for certain facilities benefitting entire regions can provide for clear rules on allocation of costs prior to any such analysis, and FERC should continue to permit them to be used where processes are in place to ensure they result in costs being allocated in a manner roughly commensurate to beneficiaries. The imprecise nature of analytical techniques used to apportion project benefits may weigh toward the adoption of techniques such as postage stamp cost allocation that set a clear formula at the outset that is not dependent on precise modeling. As the Commission observed in Order No. 1000, there are cases where "the distribution of benefits associated with a class or group of transmission facilities is likely to vary considerably over the long depreciation life of the transmission facilities amid changing power flows, fuel prices, population patters, and local economic considerations," for which such methods are particularly appropriate.[144] While the courts have rejected postage stamp allocation where there is no reason to believe that the approach would allocate costs in a manner roughly commensurate to benefits,[145] it passes

142 *See South Carolina Public Service Authority v. FERC*, 762 F.3d, 41, at 88 ("We recognize that feasibility concerns play a role in approving rates, such that the Commission is not bound to reject any rate mechanism that tracks the cost-causation principle less than perfectly."). As the U.S. Court of Appeals for the Seventh Circuit has articulated, the Commission need not "calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars." *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009).

143 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 496, July 21, 2011.

144 *Ibid.,* at P 605.

145 *See Illinois Commerce Commission v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) (noting that the Commission may not use the presumption that "new transmission lines benefit the entire network" to overcome its "duty of 'comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party'"); and *Illinois Commerce Commission v. FERC*, 756 F.3d 556 (7th Cir. 2014) (same).

legal muster where the Commission does have reason to believe this is so.[146] SPP's transmission planning and cost allocation methods provides an example of such approach, allocating the costs of "highway" projects on a postage stamp basis, but SPP is periodically conducting a review that assesses net benefits across SPP's various load zones to ensure that benefits are reasonably distributed — such as, for example, that there is a "Balanced Portfolio" of projects[147] — and reallocating costs to the extent that a given zone does not receive sufficient benefits.[148]

The success of MISO's MVP portfolio similarly demonstrates the benefits of a simple cost allocation approach where the portfolio of projects approved provides reason to believe that it will yield benefits roughly commensurate with the largely postage-stamp allocation of costs. FERC approved the MVP portfolio despite the fact that MISO did not "determine the costs and benefits of the projects subregion by subregion and utility by utility."[149] While MISO now estimates subregional benefits, such an analysis could initially have bogged down MISO's approval of the portfolio, which MISO now projects to create average monthly benefits between $4.23 and $5.13 for the average residential customers over the next 40-year period, as compared to only $1.50 per month in average costs.[150]

B. The Commission should encourage portfolio-based cost allocation

The Commission should require planning entities to provide for a cost allocation process that groups projects together to prevent the need for a multitude of time-consuming project-specific cost-allocation studies and provide for more durable results that engender stakeholder support. Conducting cost allocation at the portfolio level makes sense because "[b]enefits of a portfolio of projects will tend to be more stable and distributed more evenly."[151] The MISO MVP experience again demonstrates the value of allocating costs for a portfolio of projects together, rather than doing so one-by-one. By simultaneously pursuing 17 projects distributed across the region's geographic footprint,[152] the MISO MVP portfolio provided stakeholders with confidence that benefits would accrue to all load across the region. MISO's periodic analyses of the portfolio shows that this is in

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146 *See Illinois Commerce Commission v. FERC*, 721 F.3d 764 (7th Cir. 2013) (upholding FERC orders approving postage stamp cost allocation for a portfolio of projects); *Illinois Commerce Commission v. FERC*, 756 F.3d 556, 562 (7th Cir. 2014) (explaining that MISO's allocation of the costs of MISO's MVP portfolio on a postage stamp basis was appropriate because "[t]here was evidence that the lines would not yield highly disparate benefits to the utilities asked to contribute to their costs").

147 *See* SPP, *Open Access Transmission Tariff*, Sixth Revised Volume No. 1, Attachment O § IV, effective date: July 26, 2010.

148 *Ibid*., at Attachment J § IV.

149 *Illinois Commerce Commission v. FERC*, 721 F.3d 764, 774 (7th Cir. 2013), ICC II at 774.

150 MISO, *MTEP19*, at 7, n.d.

151 Johannes Pfeifenberger, *Improving Transmission Planning: Benefits, Risks, and Cost Allocation*, at 28, November 6, 2019.

152 *See* MISO, *Multi Value Project Portfolio: Results and Analyses*, January 10, 2012.

fact the case, with significant net benefits accruing across every local resource zone over which costs were apportioned.[153] Likewise, SPP's portfolio approach allows for a simple approach to cost allocation that nevertheless ensures benefits accrue to every load zone. And portfolio planning also underlies the use of cluster studies for interconnection which has been an improvement over project-by-project processes, as multiple projects and the transmission that they share are considered together. Portfolio planning expands those efficiencies to consider all the transmission needed for multiple purposes, not just interconnection.

A portfolio-based approach more accurately captures the benefits of proposed transmission infrastructure because one project's benefits depend on the future system as a whole, including the presence of other projects. By grouping together all projects that will be approved in a single planning period (e.g. annually), planning entities can capture these interactive effects in any benefit-cost studies that may then also be used to support cost allocation.

As we have described above, we recommend the Commission require planning entities to carry out scenario-based planning analysis that refrain from grouping projects into siloes by project type, and that instead models projects together, recognizing their multiple values and using reliability constraints as binding inputs. This modeling process lends itself to a planning process by which the costs of projects within the portfolio are allocated together. While needs may nevertheless arise for individual projects to be cost allocated outside of this general process, we recommend that the Commission recommend planning entities use a portfolio approach as a baseline.

The Commission should explicitly provide guidance against the use of load flow analysis techniques as the sole basis for cost allocation, in favor of an economically-driven approach that relies upon a broader conception of total benefits that recognizes the value of projects in the portfolio that address reliability needs alongside other benefits. This would guard against cases such as the Artificial Island development, where "PJM reported that only 10% of the estimated benefits would appear in [the] Delmarva region, but these customers would bear 90% of the costs,"[154] and the Commission ultimately found on rehearing that PJM's load-flow based distribution factor (DFAX) analysis was an unjust and unreasonable mechanism for allocating the costs of a stability-related reliability issue.[155]

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153 *See* MISO, *MTEP17 MVP Triennial Review*, at 8, September 2017.

154 *Ibid.*

155 *PJM Interconnection, L.L.C. and Certain Transmission Owners Designated,* Order Granting Rehearing and Establishing Paper Hearing Procedures, 164 FERC ¶ 61,035, at P 41, July 19, 2018.

Because a portfolio of projects will necessarily provide a wide range of different benefits, any cost allocation methodology must ensure that the sum total of these benefits is allocated in a roughly commensurate fashion. Approaches such as SPP's meet this standard because, while they rely on simplified postage stamp allocation, they include a mechanism that ensures that the approach yields the fair apportionment of costs based on benefit-cost analysis that incorporates many types of benefits. Techniques based solely on load-flow analysis fail for this purpose because they do not account for both reliability and other benefits and, therefore, may bear little relationship to the total value of benefits received.

Portfolio plans and cost allocation should be performed on a regular schedule to maximize the economies of scale and scope of considering all the projects together. However, it may also be appropriate to pursue occasional project-based plans and cost allocation in between larger less frequent portfolio plans.

C. The Commission should remedy the inconsistency with the "participant funding" approach in interconnection processes while clarifying that generators and customers who derive particularized benefits from transmission upgrades can be relied upon to a limited extent to fund new transmission infrastructure, where applicable, as part of a broader cost allocation formula

"Participant funding" is an "approach to cost allocation, in which the costs of a new transmission facility are allocated *only* to entities that volunteer to bear those costs."[156] Interconnection processes are allowed to rely on participant funding, based on the interconnection policies established by the Commission going back to Order No. 2003 issued in that year. Since interconnecting generators are often being asked to pay for network facilities that benefit other generators and other loads all around the region, the Commission should make sure that its policies remedy this inconsistency and disallow full participant funding on interconnecting generators.

At the same time, the Commission should clarify that regional cost allocation methods may, where appropriate, require limited contributions by project participants as they use the facilities in the future. In transmission planning which operates as a completely separate process from interconnection, Order No. 1000 prohibits participant funding from being used as a regional or interregional cost allocation method.[157] But while the Com-

156 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 715, July 21, 2011 (emphasis added).

157 *Ibid.*, at PP 723-729.

mission was appropriately fearful "that reliance on participant funding as a regional or interregional cost allocation method increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development,"[158] we recommend that the Commission clarify that this prohibition allows for approaches to cost allocation by which project participants pay for a limited portion but not all of the costs of a project.

As discussed in Section III.B, we recommend that the Commission require planning entities to formulate reasonable scenarios that include corporate and utility resource procurement targets. But while a scenario-based approach is the best way to plan for an uncertain future by covering a range of plausible futures, it raises the possible objection that, depending on cost allocation methodology, there may be a probability that infrastructure development could burden non-beneficiaries with the costs for achieving corporate and utility procurement targets more appropriately borne by the entities setting those targets.

To allow for appropriate cost allocation in such cases, the Commission should provide that where the evidence supports such an approach, planning entities may require particular customers and generators that derive unique benefits from the infrastructure to fund it to a limited extent. The Commission should set a specified limit on the portion of project costs that can be recovered in this manner for regional projects (e.g. 10 percent) to prevent the problems seen under participant funding schemes. Participant funding as the sole mechanism for cost recovery has proven to be problematic because it is akin to charging the next car to enter a congested highway for the cost of building a new lane. This approach is subject to the free rider problem because the entity being charged has an incentive to pull out of the process and attempt to enter once someone else has picked up the charge, and it is unfair because the new infrastructure will create system wide benefits. But requiring direct beneficiaries to fund upgrades (e.g., on a joint basis), when used to a more limited extent, could be effective. Just as tolls can prove to be an effective highway financing mechanism, assessing a charge that is truly proportional to the benefit an entity gets could help facilitate the construction of net beneficial transmission infrastructure. CAISO has a Location Constrained Resource Interconnection provision in its tariff that follows this approach.[159] Planning entities could establish models that initially assign costs to load serving entities, allowing them to get paid back as projects using the infrastructure enter the system, drawing lessons from experiences such

158 *Ibid.*, at P 723.

159 *See California Independent System Operator Corporation*, Order Granting Petition for Declaratory Order, 119 FERC ¶ 61,061, April 2007; and Bracewell LLP, *FERC Tailors Transmission to Connect Renewables*, May 1, 2007.

as the CAISO Tehachapi trunkline, where current wholesale RTO customers financed the line but are being paid back over time as generators interconnect.[160]

This type of cost allocation formula will not be necessary in all cases where a corporate or utility procurement target drives transmission needs. Facilitating corporate procurement targets may reduce total costs for regional customers by adding load or low-cost generation to the region and thereby reducing the proportion of regional costs that other customers must bear. Similarly, interconnecting electric vehicle charging equipment could benefit the system as a whole by increasing total (off-peak) system load. But it may prove to be a useful arrow in the regional cost allocation quiver in cases where an entity's procurement goal creates costs appropriately borne by that customer alone.

D. The Commission should provide more specific cost allocation requirements for inter-regional projects

Finding alignment on cost allocation for inter-regional projects is especially challenging given the potentially disparate approaches that regions may take for projects that fall solely within their borders, as well as the risk that one region could seek to impose costs on a neighboring region through this process. To address this challenge, the Commission should require regions to adopt unified cost-allocation processes for projects at their respective seams, and provide specific guardrails around the cost allocation approaches that may be used for such projects. The Commission should require that the cost allocation processes be a beneficiary pays methodology that relies on a quantified assessment of benefits and costs for every inter-regional project portfolio. To facilitate interregional cooperation and collaboration, the Commission could specify that the primary mechanism for cost allocation for seams projects should be to allocate seams project costs based on monetized benefits,[161] while allowing regions flexibility to agree on alternate cost allocation mechanisms to modify this baseline rule. Brattle Group analysts Hannes Pfeifenberger and Delphine Hou outline a number of potential cost allocation mechanisms that may facilitate interregional agreement in *Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning, including allocation according to contribution to the need, usage share of the project, or allocating costs based*

160 *See* Pedro J. Pizarro, *Transmission Planning and Development: Examples and Lessons*, at 17, February 25, 2010; CAISO, *Memorandum re: Decision on Tehachapi Project*, at 6, fn. 3 January 18, 2007 (explaining how generators would pay a pro-rata share to the extent the Tehachapi improvements are characterized as bulk transfer gen-tie lines, with customers in SCE's service territory paying the costs of the network upgrade portions of the project).

161 *See* Johannes P. Pfeifenberger and Delphine Hou, *Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning*, at 61, April 2012 (recommending such a mechanism as the first of several potential cost allocation mechanisms for Seams projects).

on the project's physical location.[162]

E. The Commission should assign costs to loads regardless of the utility's choice of whether to be an RTO member

When costs are allocated to voluntary members of Regional Transmission Organizations, those utilities can shift costs and disrupt the transmission planning process by resigning from the RTO. FERC should prevent RTO members from using this power to choose whether to be an RTO member to game the process once it becomes apparent that they may be assigned costs. Without rules put in place by the Commission, threats to leave the RTO in response to particular planning decisions may be a hindrance to efficient and reliable transmission development. Accordingly, the Commission should put a rule in place that allocates costs to regardless of such choices. For example, it may put in place a rule that assigns costs to TOs based on their planning region membership at the beginning of the planning cycle, thus preventing RTO exit from avoiding a specific cost that may become apparent during the planning process.

162 *Ibid.*

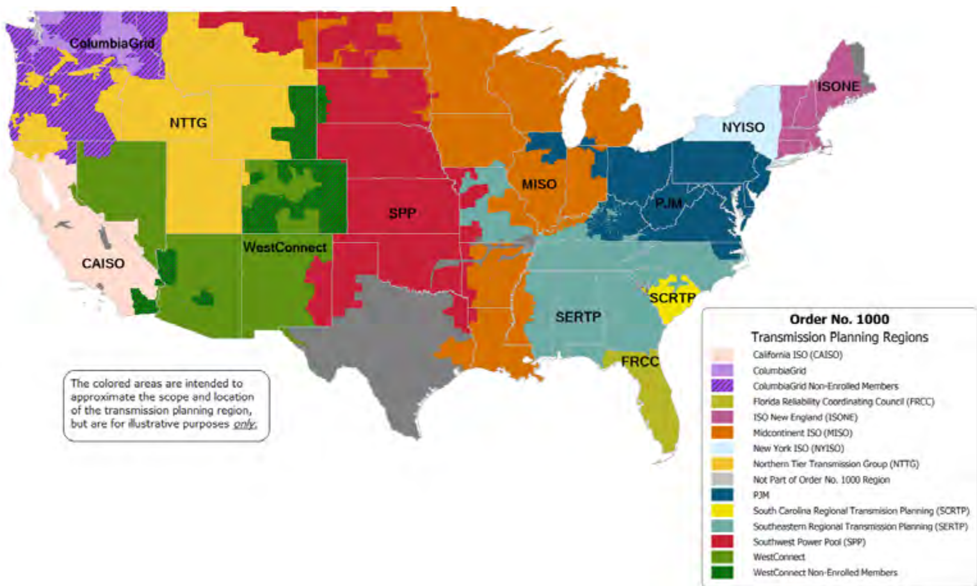
V. Ensuring cost-effectiveness

A. The Commission should ensure sufficiently broad geographic scope of planning authorities and consider requiring the formation of inter-regional planning boards with full authority to propose filings to FERC that select and cost allocate inter-regional projects

Much of the system need is interregional, connecting areas addressed by separate planning entities. Since these "regional" planning entities are really "sub-regional" and do not cover the full geographic breadth of the transmission system, the Commission should consider structural reforms to broaden transmission planning.

The Commission should consider collapsing sub-regional planning entities into larger Planning Authorities. For example, in the West, there are four Planning Authorities as shown in the map below, while the region really operates as one interconnected grid. The large load centers in the state of California cause the state to import 30 percent of its power from other parts of the region. Collapsing the four regions into one could make transmission planning more optimal.

FIGURE 14 Planning Authority Regions[163]



The Commission should also consider unifying inter-regional planning into a single process whereby a single entity composed of representatives of the applicable RTOs identifies transmission needs and solutions, selects projects and quantifies their benefits and costs, and allocates costs in a manner roughly commensurate with benefits. Doing so would completely eliminate the "triple hurdle."

The Commission could accomplish this reform by requiring the applicable regional planning entities (consistent with Order No. 1000's geographic criteria) to establish a process for the creation of joint regional boards that have full authority to independently approve projects and allocate costs across both regions.

In the event the Commission requires the establishment of such boards, it should require the planning and benefit-cost analysis processes established by such interregional planning boards to adhere to the same minimum requirements set forth in Section III, with the additional requirement that the interregional planning process must consider benefits and costs across both regions or the applicable group of regions (for multi-region planning boards).

163 FERC, *Order No. 1000 Transmission Planning Regions*, n.d.

B. FERC should take on a greater role in ensuring new transmission investment is as cost-effective as possible

More balance is needed between the bottom up and top-down planning processes, such that plans conducted by regional planning entities identify more opportunities to address transmission needs in a more cost-effective manner, and local utility plans are altered where needs are served more effectively by regional solutions.

1. The Commission should more carefully evaluate local projects that serve needs that could be addressed more cost-effectively by regional facilities

One step to remedy this imbalance would be a set of reforms designed to provide greater transparency surrounding local transmission planning and end-of-life asset management, better evaluate whether regional projects can more efficiently serve needs being met by local projects or project replacements, and closer evaluation of local projects where there is reason to believe a more efficient regional solution exists.

Order No. 890 requires "each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process,"[164] and Order No. 1000 requires every such transmission provider to "participate in a regional transmission planning process that produces a regional transmission plan and that complies with the transmission planning principles of Order No. 890."[165] Further, Order No. 1000 requires identification of "alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process."[166] The examination required under Order No. 1000 is supposed to assess regional solutions that address all types of transmission needs, including "transmission facilities needed to meet reliability requirements, address economic considerations, and/or meet transmission needs driven by Public Policy Requirements."[167]

Yet, despite these requirements, as described above, implementation of Order No. 1000 in many regions has yielded a flood of local projects that are either entirely exempt from the regional process, or that remain uninfluenced by it. For example, while the PJM Board approved $1.27 in baseline transmission investment,[168] it has approved nearly three times that amount — $3.5 billion — in "supplemental" projects.[169] As PJM explains, "Supplemental projects are identified and developed by transmission owners to address local reliability needs, including customer service and load growth, equipment material condition, operational performance and risk, and infrastructure resilience."[170] PJM reviews them to "evaluate their impact on the regional transmission system,"[171] and provides for a stakeholder process that allows for limited input,[172] but they are not subject to Board approval.[173]

There is often no close review of local projects via any other process. Despite Section 205 of the Federal Power Act's explicit language that "the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility," the Commission has implemented a policy that "presumes that all [transmission] expenditures

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164 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 1, July 21, 2011.

165 *Ibid.*, at P 146.

166 *Ibid.*, at P 148.

167 *Ibid.*

168 PJM, *Regional Transmission Expansion Plan*, at 4, February 29, 2020.

169 *Ibid.*, at 50.

170 *Ibid.*, at 4.

171 *Ibid.*

172 *Ibid.*, at 49.

173 Ibid. Further, regional transmission planning processes are yielding a mix of increasingly local projects even for infrastructure that is approved as part of regional transmission plans. *See*, e.g., Ibid., at 4. As discussed in **Section III.B**, this result is driven to a significant extent by the fact that processes used to identify regional solutions often do not base needs on the best available data and forecasting methodologies, and do not include all project benefits in their assessments of regional solutions.

are prudent."[174] Given this burden shifting, cases where costs are "disallowed and excluded from the revenue requirement . . . are rare."[175] As Dr. Paul Joskow puts it, "[f]or all intents and purposes the FERC [transmission] regulatory process is a model of cost pass-through regulation with little scrutiny of costs."[176] As noted above, some RTOs do include RTO review of local projects,[177] but this is not consistent across Planning Authorities.

Failing to proactively review the cost-effectiveness of transmission investments even where there are reasons to believe alternatives would be more appropriate has potentially tremendous costs. Utilities have an incentive to add capital assets to their rate base, so as with all regulated industries, the basic economic regulatory structure should provide for scrutiny of investments by any entity holding a license to serve as the public utility. The current approach also likely squanders valuable rights-of-way. End-of-life replacements, maintenance expenditures, and local projects by their nature utilize existing rights-of-way controlled by utilities. Upgrading and up-sizing this infrastructure in many cases will make better use of these rights-of-way, which should be fully leveraged given the challenges associated with siting transmission infrastructure. Finally, even if the investments turn out to be necessary and appropriate, the current process engenders mistrust by consumers. Many consumer and state interests have become skeptical of transmission costs being added to their bills, at a time when certain types of transmission expenditures are sorely needed.

The Commission can remedy this failure in two ways. First, it should directly require that all regional transmission planning processes better address the potential to improve upon end-of-life planning decisions by (i) requiring transmission owners to notify the regional planning entity of aging infrastructure needs far in advance of the end of an asset's life (e.g. 10 years), unless there are circumstances that prevent early notification, and (ii) requiring such projects to be approved via regional planning processes through which they may be assessed against alternatives identified by region-wide top down planning processes and assessed for benefits beyond the immediate need for repair or replacement. While some regions currently classify end-of-life projects as asset maintenance not subject to regional transmission planning processes,[178] as explained in Section VI.B.2

174 *Potomac-Appalachian Transmission Highline, LLC, PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,050, at P 100, January 19, 2017; *see also Iroquois Gas Transmission System, L.P.*, 87 FERC ¶ 61,295, 62,168, June 17, 1999 ("As a matter of procedural practice to ensure that rate cases are manageable, the Commission does not require regulated entities to 'demonstrate in their cases-in-chief that all expenditures were prudent unless the Commission's filing requirements, policy, or precedent otherwise require.' There is, in effect, a presumption of prudence which can be rebutted at hearing whenever another party 'creates serious doubt as to the prudence of an expenditure.'").

175 Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, at 13, March 2019.

176 *Ibid*.

177 *See* MISO, *Business Practices Manual Transmission Planning*, BPM-020-r21, at 22, January 1, 2020.

178 *See*, e.g., *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at P 85, August 11, 2020 (holding that regional planning requirements do not apply to "Asset Management Projects" in PJM, a category that includes end-of-life transmission infrastructure replacements).

below, the Commission has authority to reform the planning process to require more fulsome consideration of these needs via regional planning. The MISO approach noted above may be a good model for this component of the rule.

Second, the Commission should consider proactively evaluating the cost-effectiveness of local projects and end-of-life project replacements where there is reason to believe that the same needs could have been addressed more cost-effectively by a regional solution.[179] Reason to doubt the cost-effectiveness of an investment will exist where (a) scenario analysis conducted by a regional planning entity demonstrates that the need could be addressed more effectively by a regional solution; or (b) the regional planning process does not include a step that effectively examines the ability of regional solutions to more efficiently address the need.

In taking this step, the Commission should carefully calibrate the scope of projects subject to review. The Commission's current presumption of prudence for all projects is designed to ensure the administrability of rate cases,[180] and any revision to this review policy must be done according to a plan that anticipates the additional responsibilities such a change in approach would vest with the Commission. To ensure that review is aimed narrowly at the set of circumstances where the failure to interface between local and regional planning produces the most acute problems, and is carried out in the most efficient manner possible, the Commission should request input from stakeholders on how to design its criteria for review, as well as procedure for examining the prudence of such projects. For example, projects below a certain kilovolt threshold may be very unlikely to interact with regional needs, and thus should be automatically exempt from any shifting of the review burden.

Beyond incorporating such criteria at a high level into a new planning rule, the Commission could provide further guidance while retaining a degree of flexibility in implementation by issuing a policy statement explaining the scope of its new process for scrutinizing applicable local projects.[181]

179 Ari Peskoe has proposed a broader shifting of the burden of proving projects are prudent, suggesting that the Commission reverse the burden for any local project that is not incorporated into a planning process conducted by an independent entity. As Ari Peskoe discusses in his forthcoming paper, the Commission has ample authority to reverse the presumption of prudence, and could likely even directly require that local transmission planning be conducted by independent entities. *See* Ari Peskoe, Is the Utility Transmission Syndicate Forever?, forthcoming 2021.

180 *Ibid.*

181 *Ibid. (suggesting a policy statement guide FERC prudence review of transmission investments).*

2. The Commission should consider performance-based ratemaking techniques to incentivize more cost-effective transmission development

Beyond the threshold determination whether these expenditures are prudent, the Commission should assess whether and how rates may be adjusted in response to planning deficiencies. For example, there may be circumstances where a local upgrade becomes prudent to address a reliability concern, but the transmission owner's failure to appropriately examine alternatives means that the solution is not as efficient or cost-effective as it could or should have been. In such circumstances, it may be appropriate to reduce or eliminate the transmission owner's return on equity. Conversely, it may be appropriate to reward transmission owners that establish particularly effective mechanisms for identifying cost-effective regional solutions, through incentives such as shared savings mechanisms. The Commission is currently considering incentives including performance-based incentives in a rulemaking proceeding, RM20-10. Depending on how that rulemaking proceeds, there could be overlap with the recommendations in this paper.

As Dr. Paul Joskow explains, the "conventional incentive/performance based regulation mechanisms," that the Commission could theoretically apply are distinct from the "financial incentives for transmission investments meeting several specified goals."[182] The incentive mechanisms prescribed by Section 219 of the Federal Power Act are "not the kind of cost control and operating performance incentives that would normally be an important part of a performance-based incentive regulation tool kit. Rather, the incentive scheme is basically cost of service regulation with higher returns to take certain actions that advance FERC Policies."[183] But while Section 219 provides additional authority for the Commission to implement certain types of incentives, it does not constrain the Commission's ratemaking authority under Sections 205 and 206, which could be employed to apply more conventional performance-based regulation to ensure just and reasonable rates.

One performance-based option would be to adopt something like an 80/20 rule for regional/interregional projects. If a project goes over its budget, the transmission owner only recovers 20 percent of the overage. If it goes underbudget, the transmission owner recovers 80 percent of the variance, and customers get the rest.

Another option is the shared savings congestion reduction proposal by Americans for a Clean Energy Grid (ACEG), the Working for Advanced Transmission Technologies (WATT)

182 Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, at 13, March 2019.

183 *Ibid.*, at 14. *See also Economic Regulation and its Reform: What Have We Learned?* (Nancy Rose, ed.), "Incentive Regulation in Theory and Practice: Electric Distribution and Transmission Networks," Chapter 5, University of Chicago Press, 2014.

Coalition and other entities in the Commission's incentive proceeding.[184]

A third performance-based option is the Australian Energy Market Operator (AEMO) where for everyday operations and maintenance work, there is a scheme called Service Target Performance Incentive Scheme that gives utilities an incentive payment to reduce impact on the market.[185]

C. Re-establish a more collaborative approach to transmission ownership and allow RTOs more flexibility to regionally cost allocate infrastructure that has not been selected via competitive processes

Beyond the lack of efficiency between local and regional projects, another factor that in some circumstances has contributed to regional processes yielding fewer large multi-benefit projects than they otherwise could have is the perverse incentive unintentionally created by Order No. 1000's requirement that regional planning processes provide "a nonincumbent transmission developer" with "the same eligibility as an incumbent transmission developer to use a regional cost allocation method."[186]

Some regions, such as NYISO and CAISO, have successfully conducted competitive solicitations to meet regional needs, with significant stakeholder support. In other regions, however, Order No. 1000's elimination of rights of first refusal for regionally cost allocated projects has degraded the necessary planning collaboration to pursue regional projects in favor of local projects. MISO provides a stark example of the manner in which the Commission's well-intentioned push toward a more competitive framework may have had unintended consequences. The MVP portfolio approach was a collaborative effort among utilities negotiated prior to Order No. 1000. The region has since failed to assemble a comparable portfolio of large multi-benefit projects. Instead, responding to their incentives, incumbent investor owned utilities have primarily pursued local baseline reliability and other transmission projects that are subject to utility rights of first refusal.[187] In the most recent MISO Transmission Expansion Plan (MTEP), for example, nearly all projects were local and not subject to competition.[188] In former Commissioner Tony Clark's view "FERC's insistence that even one penny of regional cost allocation ended an incumbent transmis-

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184 *WATT Coalition Initial Comments*, Inquiry Regarding the Commission's Transmission Electric Incentives Policy, Docket No. PL19-3, June 26, 2019.

185 Australian Energy Regulator, *Service Target Performance Incentive Scheme*, December 2015.

186 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 332, July 21, 2011.

187 *MISO Transmission Owners v. FERC*, 819 F.3d 329 (7th Cir. 2016) (FERC permissibly exempted local baseline reliability projects from bar on rights of first refusal).

188 MISO, *MTEP19*, at 17, n.d.

sion owner's federal right of first refusal caused a series of cost allocation methodologies that previously had garnered widespread acceptance to fall apart."[189] In promulgating and affirming Order No. 1000 on rehearing, the Commission concluded that subjecting transmission projects proposed by incumbent utilities to competition was justified in order to provide for planning practices likely to yield just and reasonable rates, and to ensure those practices are not unduly discriminatory.[190] FERC concluded that "the inclusion of a federal right of first refusal, can have the effect of limiting the identification and evaluation of potential solutions to regional transmission needs," which "in turn can directly increase the cost of new transmission development that is recovered from jurisdictional customers through rates."[191] And it reasoned that "federal rights of first refusal create opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes."[192]

The evidence gathered since Order No. 1000's enactment, however, has demonstrated that these conclusions are dependent upon particular regional circumstances. Economic theory suggests that competition will deliver savings in structurally competitive sectors,[193] and comparisons of costs of competitive processes versus those of non-competitive processes have been put forward to demonstrate the benefits of competition.[194] But the transmission sector, unlike generation, is not structurally competitive. There are still large economies of scale and network externalities where all projects impact flows on the broad network, so it better fits the standard economic model of "natural monopoly," for which the standard public policy prescription is to allow monopoly entities to invest as long as a regulator is overseeing the quality and price of service. As stated fifty years ago in the classic work on the economics of regulation by Alfred Kahn "[a]s long as the tendency prevails for unit costs to decline with an increasing volume of business, because of economies of scale internal to the firm, it is more efficient, other things being equal, to have one supplier than several."[195] As a practical matter, the distortion of incumbent utili-

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189 Tony Clark, *Order No. 1000 at the Crossroads: Reflections on the Rule and Its Future*, at 10, April 2018.

190 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, at PP 357-363, May 17, 2012.

191 *Ibid*., at P 358.

192 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 286, July 21, 2011; *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, at PP 363, May 17, 2012 (affirming in relevant part).

193 *See*, e.g. J Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, March 2019; Burcin Unel, *A Path Forward for the Federal Energy Regulatory Commission Near-Term Steps to Address Climate Change*, at 13-14, September 2020.

194 *See* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 5, April 2019. Estimating the potential benefits of competition for transmission projects is difficult and different experts have come to conflicting conclusions. *See also* Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, March 2019; Concentric Energy Advisors *Building New Transmission Experience To-Date Does Not Support Expanding Solicitations*, June 2019.

195 Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, at 125/II, MIT Press, June 1988.

ty incentives that has been created by subjecting regional projects to competition while continuing to insulate local projects from competitive pressures has yielded and will likely continue to yield a suboptimal mix of new projects skewed toward local projects that is likely to yield unjust and unreasonable rates for customers. Brattle analysts observe that "[i]n some developers' views, subjecting regionally-planned projects to competition has discouraged transmission companies from suggesting potentially valuable regional projects, anticipating that the projects would need to go through competitive processes and thus could be delayed."[196] Further, as Judge Posner observed in MISO Transmission Owners v. FERC, "competition is [not] an unmixed blessing. It can result in costly duplication, and in politicking aimed at courting favor with [the regional planning entity] or FERC."[197]

Even if transmission competition were a theoretically optimal solution, it is not clear that voluntary RTOs are an administratively workable means of achieving it. Voluntary RTOs are not government regulators; they are more like associations of companies when it comes to transmission planning. They cannot be expected to choose among their members or effectively apply cost regulation to them. As Dr. Paul Joskow stated, "a competitive bidding program for new transmission links allows competing transmission developers effectively to propose alternative regulatory cost recovery formulas for determining annual revenue requirements… However, ISO's are not economic regulators in the traditional sense and have neither the expertise nor authority to adopt transmission ratemaking procedures."[198] Experience demonstrates that given RTOs' institutional structure — they are not cost regulators — a planning process that relies upon the RTO to mediate a competitive process for some projects and not others may often yield a suboptimal asset mix.

We are not arguing that competition for transmission cannot work or has not. It appears to have been successful in certain areas such as with ERCOT Competitive Renewable Energy Zones (CREZ) lines and in the U.K. where government agencies run the solicitation, and in NYISO and CAISO where utility participation in the ISO is effectively mandatory. It could also potentially work if the federal government oversaw a process for granting rights to projects from competing bidders. We are only observing that there are factors that in many cases have and should be expected to inhibit its effective use by voluntary RTOs in cases where incumbent transmission owners develop projects.

We also note the long history of success in the electric industry with joint ownership by utilities of regional network facilities. There are many forms of joint ownership in various

196 *See* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 21-22, April 2019.

197 *MISO Transmission Owners v. FERC*, 819 F.3d 329 (7th Cir. 2016).

198 *See* Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, at 2, March 2019.

regions. This collaborative approach has worked in many instances to pool the benefits and share the costs of regionally beneficial transmission.[199]

Regional circumstances may also dictate that incumbent utilities are not similarly situated with other developers, due to their unique ability to design a portfolio of local and regional transmission projects that together best serves customers. In many regions utilities are vertically integrated and subject to integrated resource planning processes at the state level that position incumbents uniquely to develop holistic solutions that will leverage generation, demand adjustments, and transmission solutions to serve future resource mixes and facilitate public policies. And siting concerns may have different effects in different regions, depend on the approach states take to these issues. In some cases, states will prioritize low-impact projects and siting constraints will dictate that only viable near-term opportunities for grid expansion is on scarce and valuable existing rights of way that utilities own. State input into the planning process may also identify occasions where, given the challenge of siting new projects that may be particularly acute in some regions, limiting competition may be a catalyst for new development because it limits the number of developers that may stir up "not in my backyard" or "NIMBY" opposition via project development activities.

Regardless, it is clear that Order No. 1000's removal of the right-of-first-refusal has had the unintended consequence of undermining regional transmission planning in some cases. Given this evidence, the Commission can reasonably conclude that a rule relaxing the broad requirement for a competitive process to be used to yield any project that gets regional cost allocation is appropriate and upholds the Commission's duties under Sections 205 and 206 of the Federal Power Act.

This approach, coupled with closer and more robust evaluation of whether regional projects can more efficiently serve local needs, as described in Section V.B above, will allow regional planning entities flexibility to find regionally appropriate solutions that will rebalance transmission portfolios in favor of a project mix that will best serve customers. In MISO, comprised almost exclusively of vertically integrated utilities, a compliance approach that centers on reinstituting a right of first refusal may be warranted. At the same time, in ISO-NE, which has experienced a similar project skew with not "a single competitive transmission project bid, selected or completed" "more than eight years after the Commission issued Order 1000,"[200] it is possible that a different approach may be war-

199 APPA, *Joint Ownership of Transmission*, February 2009.

200 *Comments of William Tong, Attorney General for the State of Connecticut, Maura Healey, Massachusetts Attorney General, Connecticut Department of Energy and Environmental Protection, Connecticut Office of Consumer Counsel and Maine Office for the Public Advocate*, Docket No. EL19-90, at 9, January 24, 2020.

ranted. Rather than reinstituting a right of first refusal, the region could prevent a skew towards local projects by better incorporating local project needs and end-of-asset-life planning into the regional process, and relying upon the Commission applying greater scrutiny to local projects for which regional planning suggests a better alternative is available. These are hypotheticals. We do not necessarily predict that the evidence will play out in this manner in these regions, but we raise these examples simply to illustrate the point that by taking a region-by-region or even context specific approach to rights of first refusal, the Commission may achieve better results across all regions.

D. The Commission should consider requiring regional planning entities to grant states a governance role in regional transmission planning

States play a central role in transmission planning that is only becoming more critical. States are the arbiters of the transmission siting process, and have a role in overseeing utilities' transmission and distribution plans as retail regulators. State involvement was critical to the successful regional transmission plans that have occurred, including MISO MVPs and SPP Priority Projects. Further, as discussed above, state public policies are playing an increasingly large role in shaping the future demand and supply mix.

Beyond standard regulatory processes, state legislation is sometimes specifically directed at transmission planning. For example, New York's Accelerated Renewable Energy Growth and Community Benefit Act calls for the New York Department of Public Service, in consultation with NYISO, the state's utilities, and other state agencies, to carry out a comprehensive power grid study at regular intervals that examines both local transmission and distribution and bulk transmission system improvements needed to reach the state's ambitious climate goals enshrined in the Climate Leadership and Community Protection Act.[201] The Act also grants the New York Power Authority, acting by itself or in collaboration with other parties, special rights to construct transmission projects found to be needed to be "completed expeditiously to meet the Climate Leadership and Community Protection Act (CLCPA) targets."[202] Other states, such as New Mexico, have transmission authorities to help plan and finance transmission that serves state energy policy goals.[203] In the wake of Order No. 1000, several states, including Minnesota, North Dakota, South Dakota, Nebraska, and Oklahoma, have enacted their own laws instituting a right

201 *See New York Accelerated Renewable Energy Growth and Community Benefit Act*, Chapter XVIII, Title 19 of NYCRR Part 900, §900-2.18 (State power grid study and program to achieve CLCPA targets).

202 *Ibid.*

203 *See https://nmreta.com/.*

of first refusal for incumbent utilities at the state level.[204] The dismissal of a challenge to Minnesota's right of first refusal law was recently affirmed by the U.S. Court of Appeals for the Eighth Circuit.[205]

Given the central importance of states to transmission planning, the Commission should consider initiating governance changes to regional planning entities so as to give states a more significant role in regional transmission planning. Some regions already give states a special role on transmission cost allocation issues.[206] And special state roles in resource adequacy are common in RTO tariffs and governing documents, another area where states have a unique statutory role.[207] For example, SPP's bylaws provide that the Regional State Committee will "determine the approach for resource adequacy across the entire region," and transmission cost allocation policy for the region.[208] The Commission should gather input from stakeholders regarding whether it would be appropriate to require governance changes of regional planning entities to incorporate a state role, and if so, what changes should be required or encouraged. Recognizing the differences in governance between RTO and non-RTO regions, the Commission should seek input on whether and how this should vary according to a region's characteristics on this dimension.

In single state transmission planning regions, the benefits of integrating states into the governance of regional transmission planning processes could be particularly acute. But larger regions will likely also see significant benefits by giving regional state committees a special governance role.

Beyond considering requiring regional planning entities to grant states a governance role in transmission planning decisions, the Commission could also facilitate better integration between the regional planning process and state proceedings by using Section 209 of the Federal Power Act to convene joint boards. Such a board could be used, for example, if one or more states demonstrate interest in aligning their transmission siting process with the regional planning process of the relevant regional planning entity(ies).

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204 *See LSP Transmission Holdings, LLC v. Sieben*, 954 F.3d 1018, 1024 n. 3 (8th Cir. 2020), (citing N.D. Cent. Code § 49-09-02.2, S.D. Codified Laws § 49-32-20, Neb. Rev. Stat.§ 70-1028, 17 Okla. Stat. § 292).

205 *Ibid*., at 1031.

206 *See* SPP, *Governing Documents Tariff, Bylaws*, First Revised Volume No. 4, at 67, effective date: August 5, 2010, (giving the Regional State Committee authority over certain transmission cost allocation issues).

207 For a discussion of resource adequacy governance provisions in multi-state RTOs, *see* Jennifer Chen and Gabrielle Murnan, *State Participation in Resource Adequacy Decisions in Multistate Regional Transmission Organizations*, March 2019.

208 SPP, *Governing Documents Tariff, Bylaws*, First Revised Volume No. 4, at 67, effective date: August 5, 2010; *Southwest Power Pool*, 106 FERC ¶ 61,110, at P 220, February 10, 2004 ("The RSC should . . . determine the approach for resource adequacy across the entire region."); *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,010, at P 93, October 1, 2004, ("We reject arguments that the RSC is infringing on SPP's own section 205 filing rights.").

E. Produce plans on a regular schedule

To ensure effective planning that is updated to evolving circumstances, the Commission should require regular updates, such as every two years.

F. Produce plans in operations time frame

A FERC planning rule should provide for planning in different time frames. Congestion on the system is widespread and costs consumers roughly $6.1 billion per year.[209] Yet if one only looks at the system a year or two ahead of time, much of that congestion does not exist. That is because congestion is often a function of planned transmission line outages that are not known in that time frame. Transmission planning should include an operational time frame component. Looking out two or three months ahead when planned outages are known allows fast deployment of Grid-Enhancing Technologies to reduce or resolve that congestion.

209 Jesse Schneider, *Transmission Congestion Costs in the U.S. RTOs*, August 14, 2019 (updated November 12, 2020).

VI. The Commission has authority to carry out these reforms

Broadly speaking, to issue a new planning rule under Section 206 of the Federal Power Act, the Commission must find based on substantial evidence that existing planning practices are not just and reasonable or are unduly discriminatory. Evidence of challenges that have persisted despite the progress made under Orders No. 890 and 1000 clears this bar with room to spare. As discussed in Appendix A, numerous studies demonstrate that large, high-voltage transmission infrastructure would yield significant net benefits. Yet regional planning processes are largely not approving such infrastructure, instead yielding locally focused projects that in many cases are likely not as cost-effective as regional or interregional solutions could be. This has overburdened interconnection processes, which are becoming clogged and unworkable. These factors all demonstrate the need for broad planning reforms.

At a more granular level, the Commission has ample authority to adopt the specific solutions we have suggested in this report, as discussed further below.

A. Planning

1. *The Commission can require regions to plan based on the best available data and forecasting methodologies*

We recommend that the Commission require regions to plan based on reasonable future scenarios that use the best available data and forecasting methodologies. Such planning, which requires the incorporation of not only factors such as resource cost curves, but also public policies as well as corporate and utility procurement targets, falls under FERC's standard power to require planning to be conducted using reasonably available information, just as FERC requires RTOs establish capacity requirements based on their projections of load that is influenced by state energy efficiency policies and other factors. The Commission is permitted to "recognize[] that state and federal policies might affect the transmission market" and plan accordingly.[210]

210 *South Carolina Public Service Authority v. FERC*, 762 F.3d at 89 (D.C. Cir. 2014).

Section 217(b)(4) of the Federal Power Act also supports a requirement to plan based on the best available data and forecasting methodologies, and to include public policies and utility and corporate renewable procurement goals within planning scenarios. It requires the Commission to exercise its authority "in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of load-serving entities."[211] Load serving entities' service obligations will be more accurately predicted by the best available forecasting methodologies, and will naturally depend upon both public policies and the resource preferences of their customers.[212]

2. The Commission can require regional planning entities to approve transmission plans that maximize net benefits

The Commission can also require regional planning entities to approve transmission plans that maximize net benefits using the same general authority it relied upon in promulgating Order No. 1000. Like Order No. 1000, such a requirement focuses on "process" and is "not intended to dictate substantive outcomes."[213] While establishing minimum standards for benefit-cost analysis is a more detailed requirement than requirements such as Order No. 1000's directive that any threshold regional planning entities apply for benefit-cost analysis must be no lower than 1.25, it likewise does not dictate that public utility transmission providers build any particular infrastructure and instead simply mandates that they follow a series of prescribed steps designed to yield just and reasonable rates. As with Order No. 1000, "[t]he substance of a regional transmission plan and any subsequent formation of agreements to construct or operate regional transmission facilities" would "remain within the discretion of the decision-makers in each planning region."[214]

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211 *16 U.S.C. 824q(b)(4)*.

212 As the Commission explained in Order No. 1000-A, "many, if not all, of the Public Policy Requirements will likely impose legal obligations on load-serving entities." *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, at P 175, May 17, 2012.

213 *South Carolina Public Service Authority v. FERC*, 762 F.3d at 58 (D.C. Cir. 2014), (quoting Order No. 1000-A, at P 188, 77 Fed. Reg. at 32,215).

214 *Ibid.*

B. Governance, oversight, and formation of new planning entities

1. The Commission can require regions to form joint inter-regional planning boards that have full authority to propose FPA section 205 filings that select projects and allocate their costs, and form a new planning entity to assess national transmission opportunities

In considering the establishment of joint inter-regional planning boards that hold full authority to select and dictate cost allocation methodologies for projects included within an inter-regional plan, the Commission could rely on the same authority it used in Order No. 1000 to require regional planning to be conducted even in non-RTO regions.

As the D.C. Circuit explained in upholding Order No. 888 and Order No. 1000, Section 202(a) of the Federal Power Act's reference to voluntary coordination and Section 202(b) and 211's grant of authority to order interconnection and wheeling do not limit the ability of the Commission to compel rules for planning new facilities that remedy unjust, unreasonable, and discriminatory behavior under Section 206.[215] Here, as was the case in Order No. 1000, the evidence demonstrates that existing transmission planning practices are unjust, unreasonable, and unduly discriminatory with respect to interregional planning because they have not resulted in the approval of a single inter-regional project, despite a large amount of evidence suggesting that such projects would yield net benefits.

The Commission may explore different potential organizational structures for such interregional planning boards. One option may be to require the formation of new, independent entities. While such entities would not themselves be "public utilities" under the Federal Power Act, the Commission could nevertheless require transmission owners in the relevant regions to file agreements governing each interregional board with the Commission. As the Commission explained in its policy statement governing Regional Transmission Groups (similar entities that did not themselves operate transmission but governed transmission planning and operations by member entities), "under section 205(c) of the Federal Power Act (FPA), public utilities must file with the Commission the classifications, practices, and regulations affecting rates and charges for any transmission or sale subject to the Commission's jurisdiction, together with all contracts which in any manner affect or relate to such rates, charges, classifications and services."[216] Thus,

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215 *See Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 686 (D.C. Cir. 2000) ("Otter Tail does not constrain FERC from mandating open access where it finds circumstances of undue discrimination to exist."); *South Carolina Public Service Authority v. FERC*, 762 F.3d at 61 (2014), ("To the extent the court in Central Iowa interpreted Section 202(a) to mean that 'Congress intended coordination and interconnection arrangements be left to the 'voluntary' action of the utilities,' there is nothing to suggest that the court purported to interpret the meaning of 'coordination' in regard to the planning of future facilities.").

216 *Policy Statement Regarding Regional Transmission Groups*, 58 Fed. Reg. 41,626, August 5, 1993.

an agreement governing such an interregional planning board, like a Regional Transmission Group Agreement "that in any manner affects or relates to jurisdictional transmission rates or services," would need to "be approved or accepted by [the] Commission as just, reasonable, and not unduly discriminatory or preferential under [section 205 of] the FPA."[217]

Another option may be to refrain from establishing new, independent organizations and instead dictate that relevant RTO agreements and utility tariffs provide for the participation in such a board and designation to such board full, binding authority to select and cost allocate projects in a manner that cannot be subsequently second guessed by the relevant individual RTO boards or utilities.

2. The Commission can enhance the transparency of transmission planning

Currently, the planning regions possess and report disparate information[218] on transmission needs and investments. Some regions do not publish cost information for approved projects, which limits the ability of stakeholders to assess such projects.[219] Further, there is no centralized place that tracks the costs of transmission projects "planned by the local transmission owners that are not subject to full ISO/RTO regional planning review."[220]

Building on Order No. 890's transparency requirements, the Commission could require more specific minimum data transparency standards as part of a new rule, drawing on the examples set by leading regions such as MISO and SPP, which "currently maintain . . . transparent cost recording and tracking processes for projects approved through their regional planning processes."[221] As Brattle Group analysts have recommended, the Commission should require that regional planning entities at minimum "have a detailed project tracking mechanism that consistently document[s] project cost estimates at various stages of the project, particularly when the project needs are first identified and at the completion of the projects."[222]

217 *Ibid.*

218 Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 24, April 2019.

219 *Ibid.*, at 23-26 (describing data reporting practices, noting that their "analysis was not able to cover NYISO, which does not publish cost information on approved projects").

220 *Ibid.*, at 26.

221 *Ibid.*

222 *Ibid.*, at 24.

3. *The Commission can require regional transmission plans to incorporate end-of-life project planning*

The Commission could mandate end-of-life project planning be considered as part of the regional planning process by reasoning that such planning must be conducted in order to design new transmission facilities where appropriate. Regulating this planning process can be articulated as a requirement to plan *new* projects, without requiring coordination of existing facilities.

Opponents of Order No. 1000 argued that the Commission exceeded its authority in mandating regional transmission planning, as opposed to simply regulating *voluntary* planning arrangements.[223] Section 202(a) of the Federal Power Act "empower[s] and direct[s]" the Commission "to divide the country into regional districts for the voluntary interconnection and coordination of facilities."[224] But in upholding Order No. 1000, the Court of Appeals for the District of Columbia Circuit agreed with the Commission that Section 202(a)'s reference to voluntary coordination does not preclude mandatory planning activities. Rather, the voluntary coordination referred to in Section 202(a) applies only to the operation of existing facilities, not to the planning of new facilities, which "'occurs before [facilities] can be interconnected.'"[225]

We recommend that the Commission explicitly include end-of-life planning decisions within the scope of its new planning rule. While it is true that end-of-life infrastructure replacements are currently classified as asset maintenance in some regions,[226] the Federal Power Act provides the Commission with discretion to reclassify such projects as new construction. The Federal Power Act does not specify what constitutes a "facility" with regard to section 202(a)'s language governing "voluntary interconnection and coordination of facilities"; an interpretation by the Commission that rebuilding all or a significant part of an existing facility constitutes the creation of a new facility rather than maintenance of an existing one is reasonable and not arbitrary and capricious,[227] and would constitute the same type of interpretation that was upheld in *South Carolina Public Service Authority v. FERC* as permissibly distinguishing between planning new facilities and regulating the coordination of existing ones.[228] The Commission, without requiring a transmission owner to engage in any involuntary coordination of an existing facility while it is being

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223 *See South Carolina Public Service Authority v. FERC*, 762 F.3d, 41, 55-64 (D.C. Cir. 2014).

224 *16 U.S.C. § 824a(a)* (emphasis added).

225 *South Carolina Public Service Authority v. FERC*, 762 F.3d at 59 (D.C. Cir. 2014). (quoting Order No. 1000, at P 124, 77 Fed. Reg. at 32,206).

226 *See,* e.g., *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at P 85, August 11, 2020, (holding that regional planning requirements do not apply to "Asset Management Projects" in PJM, a category that includes end-of-life transmission infrastructure replacements).

227 *See Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837 (1984) (holding that where a statute is "silent or ambiguous on [a] specific issue," courts must defer to an agency's reasonable interpretation).

228 *See South Carolina Public Service Authority v. FERC*, 762 F.3d at 59.

planned, can nevertheless establish rules with regard to whether a new facility should be built in its place that more efficiently meets regional needs.

The Commission can provide guidance dictating that when expenditures exceed a certain threshold, they no longer constitute 'maintenance' activities that are excluded from regional transmission planning.[229] The Commission can reason that rules that classify "asset management" activities as maintenance, even where those activities involve replacement of all or most of a given existing facility,[230] create an inappropriate incentive for utilities to reconstruct existing lines even where other alternatives are more efficient, and is not compelled by the text of the Federal Power Act.

To the extent that the Commission's directive in this area conflicts with existing RTO operating agreements concerning which facilities are subject to regional planning, the Commission can argue that the *Mobile-Sierra* doctrine does not apply, just as it did not apply with regard to the Commission's mandate that Rights-of-First-Refusal be removed from tariffs governing regional planning processes.[231] In upholding the Commission's Right of First Refusal (ROFR) removal mandate, the D.C. Circuit reasoned that *Mobile-Sierra* did not apply because the contractual terms altered by the Commission's directive were "arrived at by horizontal competitors with a common interest to exclude any future competition."[232] The same is true here. Transmission Owners' decision not to give PJM control over end-of-life planning decisions was one made by horizontal competitors to exclude such projects from future competition, and is not reflective of arm's length bargaining that could be expected to arrive at a competitive result.

4. The Commission can apply greater oversight to local transmission plans

The Commission has authority to evaluate local transmission projects where appropriate to ensure the same needs cannot be more cost-effectively met via regional and interre-

229 In many cases, this would require broadening the scope of planning tariffs and agreements. For example, FERC recently held that PJM's Consolidated Transmission Owner's Agreement (CTOA) requires a project to "expand" or "enhance" the PJM grid for planning to be transferred to PJM. *See* *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at P 83, August 11, 2020. In adopting new criteria to distinguish infrastructure maintenance from grid upgrades, the Commission should gather input from stakeholders regarding how to define the threshold dividing these activities (e.g. whether as an absolute dollar amount or as a percentage of an existing facility, how to define the scope of a facility for purposes of this rule, etc.).

230 *See*, e.g., *Ibid.*, at P 85 (finding that PJM's proposal to designate replacement projects as "asset management" projects exempt from Order No. 890's requirements is just and reasonable). *See also* 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.

231 *See* *Oklahoma Gas and Electric Co. v. FERC*, 827 F.3d 75 (D.C. Cir. 2016).

232 *Ibid.*, at 80 (D.C. Cir. 2016).

gional infrastructure.[233] Evaluating the cost-effectiveness of such projects would be more consistent with Section 205 of the Federal Power Act, which places the "burden of proof" on the filing party.[234]

To prevent such a change in the burden of proof for some projects from overburdening the Commission's capacity to administer rate cases, the Commission could issue policy guidance regarding its scope and process for review.

5. The Commission can take a case-by-case approach to approving regional planning tariffs that reinstitute a right of first refusal

While the Commission was justified in mandating the removal of rights of first refusal from regional transmission planning tariffs, as discussed in Section V.D, evidence in implementing Order No. 1000 warrants a change in position by the Commission.

In determining that in some circumstances a new tariff proposal that contains a right of first refusal may yield just and reasonable rates, the Commission can point to the manner in which a mismatch in rights of first refusal at the regional and local level has led to a skewed, non-optimal project mix. At the same time, the Commission could approve a regional transmission plan that continues to omit a right of first refusal if the evidence dictates that inclusion of end-of-life project decisions within such a plan, coupled with a process for evaluating whether a regional project more efficiently serves a local need, creates incentives that will prevent the project skew we have seen in the past.

As explained in Section V.D, the Commission can also point to the experience in implementing Order No. 1000 as demonstrating that in certain circumstances, different treatment between incumbent transmission owners and non-incumbents is justified and not "undue discrimination," recognizing the role incumbents play in operating the local system, and in some regions, participating in integrated resource planning processes at the state level.

233 Existing Commission precedent applies a presumption of prudence to local transmission plans. *See Potomac-Appalachian Transmission Highline, LLC PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,050, at P 100, January 19, 2017; *see also Iroquois Gas Transmission System, L.P.*, 87 FERC ¶ 61,295, 62,168, June 17, 1999, ("As a matter of procedural practice to ensure that rate cases are manageable, the Commission does not require regulated entities to 'demonstrate in their cases-in-chief that all expenditures were prudent unless the Commission's filing requirements, policy, or precedent otherwise require.' There is, in effect, a presumption of prudence which can be rebutted at hearing whenever another party 'creates serious doubt as to the prudence of an expenditure.'"). Nevertheless, the Commission could appropriately reason that such a presumption is not appropriate where evidence suggests that a regional transmission solution may more efficiently meet the same need.

234 *16 U.S.C. § 824d(e)*; *see* Ari Peskoe, Is the Utility Transmission Syndicate Forever?, forthcoming 2021.

Appendix A

EVIDENCE OF THE NEED FOR LARGE REGIONAL AND INTERREGIONAL TRANSMISSION

Numerous studies of the future resource mix find that large amounts of power must be able to move back and forth across regions, and large regional and interregional transmission is needed for this to happen. This evidence includes:

- A study by leading grid experts at the National Oceanic and Atmospheric Administration (NOAA), found that moving away from a regionally divided network to a national network of HVDC transmission can save consumers up to $47 billion annually while integrating 523 GWs of wind and 371 GWs of solar onto the grid.[235]
- The NREL *Interconnections Seam Study* shows that significant transmission expansion and the creation of a national network will be essential in incorporating high levels of renewable resources, all the while returning more than $2.50 for every dollar invested.[236] The study found a need for 40-60 million MW-miles of alternating current (AC) and up to 63 million MW-miles of direct current (DC) transmission for one scenario. The U.S. has approximately 150 million MW-miles in operation today.
- A study by ScottMadden Management Consultants on behalf of WIRES concluded, "as more states, utilities, and other companies are mandating or committing to clean energy targets and agendas, it will not be possible to meet those goals without additional transmission to connect desired resources to load. Similarly, the current transmission system will need further expansion and hardening beyond the traditional focus on meeting reliability needs if the system is to be adequately designed and constructed to withstand and timely recover from disruptive or low probability, high-impact events affecting the resilience of the bulk power system."[237]
- Dr. Paul Joskow of MIT has reviewed transmission planning needs and concluded that "[s]ubstantial investment in new transmission capacity will be needed to allow wind and solar generators to develop projects where the most attractive natural

235 Alexander E. MacDonald et al., *Future Cost-Competitive Electricity Systems and Their Impact on U.S. CO2 Emissions*, Nature Climate Change 6, at 526-531, January 25, 2016.

236 Aaron Bloom, *Interconnections Seam Study*, August 2018.

237 Scott Madden, *Informing the Transmission Discussion: A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States*, January 2020.

wind and solar resources are located. Barriers to expanding the needed inter-regional and internetwork transmission capacity are being addressed either too slowly or not at all."[238]

- The Commission itself recently reviewed transmission needs and barriers and "found that high voltage transmission, as individual lines or as an overlay, can improve reliability by allowing utilities to share generating resources, enhance the stability of the existing transmission system, aid with restoration and recovery after an event, and improve frequency response and ancillary services throughout the existing system."[239]
- A study of the Eastern Interconnection for the state of Minnesota found that scenarios with interstate transmission expansion can introduce annual savings to Minnesota consumers of up to $2.8 billion, with an annual savings for Minnesotan households of up to $1,165 per year.[240]
- Analysts at The Brattle Group estimate that providing access to areas with lower cost generation to meet Renewable Portfolio Standards (RPS) and clean energy needs through 2030 could create $30-70 billion in benefits for customers, and multiple studies have identified potential benefits of over $100 billion.[241]
- The Princeton University Net Zero America study of a low carbon economy found "[h]igh voltage transmission capacity expands ~60% by 2030 and triples through 2050 to connect wind and solar facilities to demand; total capital invested in transmission is $360 billion through 2030 and $2.4 trillion by 2050."[242]
- A study by MIT scientists found that inter-state coordination and transmission expansion reduces the cost of zero-carbon electricity by up to 46% compared to a state-by-state approach.[243] To achieve these cost reductions the study found a need for approximately doubling transmission capacity, and "[e]ven in the ''5x transmission cost'' case there are substantial transmission additions."[244]

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238 Paul Joskow, *Transmission Capacity Expansion is Needed to Decarbonize the Electricity Sector Efficiently*, Joule 4, at 1-3, January 15, 2020.

239 FERC, *Report on Barriers and Opportunities for High Voltage Transmission*, at 39, June 2020.

240 Vibrant Clean Energy, *Minnesota's Smarter Grid*, July 31, 2018.

241 J. Michael Hagerty, Johannes Pfeifenberger, and Judy Chang, *Transmission Planning Strategies to Accommodate Renewables*, at 17, September 11, 2017.

242 Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, at 77, December 15, 2020.

243 Patrick R. Brown and Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, Joule, December 11, 2020.

244 *Ibid., at 12.*

- A recent study to compare the "flexibility cost-benefits of geographic aggregation, renewable overgeneration, storage, and flexible electric vehicle charging," as "pathways to a fully renewable electricity system" found that "[g]eographic aggregation provides the largest flexibility benefit with ~5–50% cost savings.[245] The study found that "With a major expansion of long-distance transmission interconnection to smooth renewable energy variation across the continent, curtailment falls to negligible levels" at a 60% renewable penetration, from 5% in the case without transmission. In the 80% renewable case, transmission reduced curtailment from 12% to 5%."[246]

- The Brattle Group analysts find that "$30–90 billion dollars of incremental transmission investments will be necessary in the U.S. by 2030 to meet the changing needs of the system due to electrification, with an additional $200–600 billion needed from 2030 to 2050."[247]

- Analysis conducted for MISO found that significant transmission expansion was economical under all future scenarios, with the largest transmission expansion needed in Minnesota, the Dakotas, and Iowa. In the carbon reduction case, transmission provided $3.8 billion in annual savings, reducing total power system costs by 5.3%.[248] MISO's Renewable Integration Impact Assessment conducted a diverse set of power system studies examining up to 50% Variable Energy Resources (VER) (570GW VER) in the eastern interconnection. Within the MISO footprint, this included the following transmission expansion: 590 circuit-miles of 345kV and below, 820 circuit-miles of 500kV, 2040 circuit-miles of 765kV and 640 circuit-miles of HVDC.[249]

- Brattle group analysts, on behalf of WIRES, demonstrate that transmission expansion creates trading opportunities across existing regional and interregional constraints. The report finds, using existing wholesale power price differences between SPP and the Northwestern U.S., that "adding 1,000 MW of transmission capability would create approximately $3 billion in economic benefits on a present value basis."[250]

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245 Bethany A. Frew et al., *Flexibility Mechanisms and Pathways to a Highly Renewable U.S. Electricity Future*, Energy, Volume 101, at 65-78, April 15, 2016.

246 *Ibid*.

247 Dr. Jürgen Weiss, J. Michael Hagerty, and María Castañer, *The Coming Electrification of the North American Economy*, at ii, March 2019.

248 Vibrant Clean Energy, *MISO High Penetration Renewable Energy Study for 2050*, at 23-24, January 2016.

249 Wind Solar Alliance, *Renewable Integration Impact Assessment Finding Integration Inflection Points of Increasing Renewable Energy*, January 21, 2020.

250 Johannes Pfeifenberger and Judy Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon Constrained Future*, at 16, June 2016.

- In its HVDC Network Concept study, MISO estimates that expanding east-to-west and north-to-south transmission interties can generate investment cost savings of approximately $38 billion through load diversity benefits that would reduce nation-wide generation capacity needs by 36,000 MW.[251]

- A study prepared for the Eastern Interconnection States Planning Council, National Association of Regulatory Utility Commissioners, and the Department of Energy estimates that $50–110 billion of interregional transmission will be needed over the next 20 years to cost-effectively support new generation investment. A co-optimized, anticipatory transmission planning process is estimated to reduce total generation costs by $150 billion, compared to a traditional transmission planning approach, and would generate approximately $90 billion in overall system-wide savings.[252]

- SPP found that a portfolio of transmission projects constructed in the region between 2012 and 2014 at a cost of $3.4 billion is estimated to generate upwards of $12 billion in net benefits over the next 40 years. The net present value is expected to total over $16.6 billion over the 40-year period, resulting in a benefit-to-cost ratio of 3.5.[253]

- MISO estimates that its 17 Multi-Value Projects (MVPs), approved in 2011, will generate between $7.3 to $39 billion in net benefits over the next 20 to 40 years, which will result in a total cost-benefit ratio of between 1.8 to 3.1. Typical residential households could realize an estimated $4.23 to $5.13 in monthly benefits over the 40-year period.[254]

- A study conducted by the Eastern Interconnection Planning Collaborative on the need for interregional transmission projects to meet national environmental goals found that an efficient interregional transmission planning approach to meet a 25% nation-wide RPS standard would reduce generation costs by $163–197 billion compared to traditional planning approaches.[255] Phase 2 of the study found that the transmission investment necessary to support the generation and the environmental compliance scenarios associated with these savings ranges from $67 to $98

251 MISO, *HVDC Network Concept*, at 3, January 7, 2014.

252 Andrew Liu et al., *Co-optimization of Transmission and Other Supply Resources*, September 2013.

253 SPP, *The Value of Transmission*, at 5, January 26, 2016.

254 MISO, *MTEP19*, at 6-7, n.d.

255 Eastern Interconnection Planning Collaborative, *Phase 1 Report: Formation of Stakeholder Process, Regional Plan Integration and Macroeconomic Analysis*, December 2011.

billion.[256] These results indicate that the combination of interregional environmental policy compliance and interregional transmission may offer net savings of up to $100 billion.

- A study comparing pro-active planning to reactive planning found significant benefits to pro-active planning because it is able to co-optimize generation and transmission. “Transmission planning has traditionally followed a “generation first” or “reactive” logic, in which network reinforcements are planned to accommodate assumed generation build-outs. The emergence of renewables has revealed deficiencies in this approach, in that it ignores the interdependence of transmission and generation investments. For instance, grid investments can provide access to higher quality renewables and thus affect plant siting. Disregarding this complementarity increases costs. In theory, this can be corrected by “proactive” transmission planning, which anticipates how generation investment responds by co-optimizing transmission and generation investments. We evaluate the potential usefulness of co-optimization by applying a mixed-integer linear programming formulation to a 24-bus stakeholder-developed representation of the U.S. Eastern Interconnection. We estimate cost savings from co-optimization compared to both reactive planning and an approach that iterates between generation and transmission investment optimization. These savings turn out to be comparable in magnitude to the amount of incremental transmission investment.”[257]

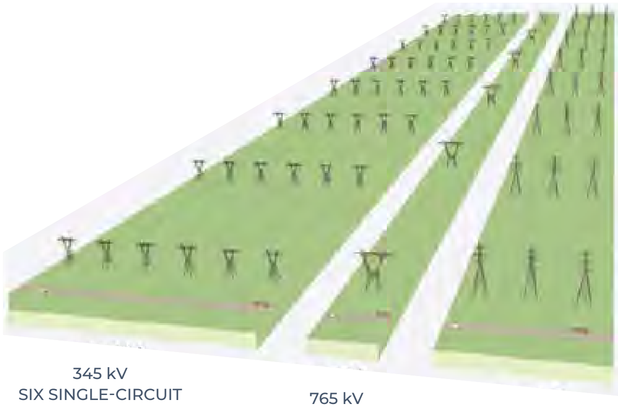
- There are extremely large economies of scale in transmission, such that building at the appropriate scale achieves lower costs for each Megawatt-hour delivered. The chart below shows the much lower cost for larger conductor sizes.[258]

256 Eastern Interconnection Planning Collaborative, *Phase 2 Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios and Gas-Electric System Interface Study*, June 2, 2015.

257 Evangelia Spyrou, Jonathan L. Ho, Benjamin F. Hobbs, Randell M. Johnson, and James D. McCalley, *What Are the Benefits of Co-Optimizing Transmission and Generation Investment? Eastern Interconnection Case Study*. IEEE Transactions on Power Systems 32 (6): 4265–77, January 27, 2017.

258 *Fabricators & Manufacturers Association, International*.

FIGURE 15 Lower Transmission Cost per MW-Mile for Larger Conductors



345 kV
SIX SINGLE-CIRCUIT TOWERS
(900-FT RIGHT-OF-WAY)

765 kV
ONE SINGLE-CIRCUIT TOWER
(200-FT RIGHT-OF-WAY)

345 kV
THREE DOUBLE-CIRCUIT TOWER
(450-FT RIGHT-OF-WAY)

TRANSMISSION VOLTAGE (KV)	COST PER MILE ($/MILE)	CAPACITY (MW)	COST PER UNIT OF CAPACITY ($/MW-MILE)
230	$2.077 million	500	$5,460
345	$2.539 million	967	$2,850
500	$4.328 million	2,040	$1,450
765	$6.578 million	5,000	$1,320

Customer and reliability benefits from an increase in transmission construction have also been noted in studies focused on networks outside of the U.S. that have the same fundamental physics and economics at work.

- The "European e-Highway 2050" study found that interregional transmission investments allow for the integration of lower-cost, region-wide renewable resources, which reduce the cost of achieving a low-carbon electricity sector. Additionally, in high-renewable generation scenarios, interregional transmission investments are found to be highly cost effective with a payback period of just one year.[259]

- A study conducted by McKinsey & Company analysts found that, in Europe, the most cost-effective way to reach 40% to 45% renewable generation targets in 2050 requires doubling existing region-wide transmission capabilities by 2020 and quadrupling transmission capabilities by 2050. Germany, in particular, would need to significantly expand its interregional transmission capabilities to facilitate Europe-wide resource planning coordination.[260]

- Achieving Europe's overall renewable energy policy objectives, according to a report prepared for the Directorate General for Energy of the European Commission, finds

259 E-Highway 2050, Modular Development Plan of the Pan-European Transmission System 2050, *D2.3 System Simulations Analysis and Overlay-Grid Development*, April 16, 2015.

260 McKinsey & Company, *Transformation of Europe's power system until 2050Including specific considerations for Germany*, October 2010.

the most cost-effective path to achieving Europe's renewable energy policy objectives involves a substantial expansion of transmission networks, which composes 15% to 20% of total investment needs in all scenarios. A delay or lack of regional and interregional transmission was found to increase overall system-wide costs as well as increase levels of price volatility within regional markets.[261]

261 DNV GL - Energy, *Integration of Renewable Energy in Europe*, June 12, 2014.

Appendix B

HIGH LEVEL OVERVIEW AND ASSESSMENT OF CURRENT PLANNING APPROACHES

In most cases today, regional planning is limited to near term knowns and protecting firm service using scenarios which do not adequately incorporate likely future changes. Below, we summarize existing processes and their infirmities.

Order Nos. 890 and 1000 require a regional planning process in all areas of the country, extending transmission planning regions beyond ISO and RTOs. In almost all non-RTO areas, the participating utilities' individual transmission plans are consolidated to create a baseline regional reliability plan which is used to evaluate other proposals for both regional transmission needs and solutions. In these transmission planning regions, analysis of opportunities to expand beyond the baseline regional reliability plan are seldom robust, and as a result few projects have resulted from the regional planning process in non-RTO areas.

RTOs tend to have more robust regional planning processes than non-RTO regional planning entities. These RTO planning processes consist of at least two main steps: (1) a regional reliability assessment that identifies projects to meet reliability needs; and (2) a process designed to identify projects that will enhance the regional economic efficiency of the transmission system. They also carry out separate "tariff services" processes to develop transmission pursuant to customer load additions, transmission service requests, or generator interconnection requests. Infrastructure built pursuant to these tariff services processes is incorporated into regional transmission plans, but not driven by them. In addition, tariff service processes result in minimal system upgrades to provide the requested service, with little or no consideration of optimal long-term plans. Regions vary in the degree to which local projects, as well as upgrades and maintenance of existing infrastructure, are included in the regional reliability planning process or instead pursued according to separate local planning processes that later feed into the regional needs assessment. They also vary in the extent to which they have a separate process designed to identify projects to serve public policy goals, or projects driven by both economics and policy.

A. Reliability planning

Utilities have always focused on providing reliable service to customers as the top priority. Reliability planning processes, as their name suggests, tend to focus solely on meeting reliability standards and identifying projects based on their ability to address projected violations of reliability standards.[262] North American Electric Reliability Corporation (NERC) reliability criteria have evolved to establish system performance requirements to address thermal, voltage and stability needs of a secure bulk power system. Regional plans incorporate not only NERC criteria, but also regional and local criteria. Criteria have traditionally focused on deterministic needs of the bulk power system to evaluate system performance during system peak conditions, light load, and other planning scenarios.

Reliability planning processes begin with a baseline reliability assessment that identifies the ability of local and regional transmission infrastructure to meet reliability criteria. For example, MISO's baseline reliability study examines all infrastructure rated 100 kV and above, carrying out "power-flow models reflective of two-year out, five-year out, and ten-year out system conditions in accordance with NERC Transmision Planning (TPL) standards,"[263] as well as a variety of other studies such as a load deliverability analysis to assess system performance across relatively-near term conditions.[264]

RTOs then assess reliability according to a range of future scenarios that project system resource mix and demand across a longer time horizon. For example, MISO annually develops "Futures" to project various potential system resource mix and demand scenarios, which are used as an input into the reliability planning process.[265] The process for developing such future scenarios varies widely by region. Some regions, such as MISO and SPP, incorporate state renewable portfolio standards into their future grid mix scenarios.[266] Others, such as PJM, do not.[267] Efforts are underway in many regions to complement deterministic assessments with probabilistic techniques, which are paramount to manage the allocation of limited capital to the best system improvements given the variable na-

262 *See*, e.g., PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 2.1.2, October 1, 2020.

263 MISO, *Business Practices Manual Transmission Planning*, § 4.3.3, effective date: May 1, 2020.

264 *Ibid.*, § 4.5.1.

265 *Ibid.*, at § 4.4.2.5 ("It is necessary that the transmission plan is developed to be effective under the range of Futures studied. Therefore, the proposed transmission plan will be tested under each of the agreed upon Future for economic results (e.g. benefit-to-cost ratios, etc.), reliability performance (e.g., NERC standards, etc.), and public policy performance (e.g. compliance with RPS mandates, etc.).

266 *See*, e.g., Ibid., at § 4.3.3.2 ("[S]ufficient renewable generation will be modeled to meet renewable portfolio standard mandates effective during the applicable planning horizon."); SPP, *Integrated Transmission Planning Manual*, § 2.2.1.3, July 20, 2017, (requiring renewable resource targets set by state renewable portfolio standard requirements to "be met in each of the study years").

267 *See* PJM, *Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.*, Schedule 6, § 1.5.7, effective date September 17, 2010.

ture of new renewable resources and loads, plus uncertainties regarding key variables. [268]

B. Local projects and maintenance activities

Transmission owners have an obligation to serve and must maintain assets, including those that have been placed under the operational control and authority of an RTO. Regions vary in how they conduct planning of local assets and maintenance activities based on the degree of control that has been given to the RTO. The Commission held in 2018 that Order No. 890 does not require Transmission owners "to allow the RTO to do to all planning for local or Supplemental Projects."[269] In many regions, such as PJM, transmission owners carry out separate local planning processes, which address a wide range of transmission needs, including upgrades and maintenance of existing infrastructure.[270] These local processes act as an input to regional plans, but are not subject to approval by the regional planning entity and there is often minimal coordination between the local and regional planning process to facilitate modification of local projects in response to the development of regional solutions. Other regions, such as SPP, have a very close degree of coordination between local and regional planning. With the exception of Southwestern Public Service Company, all transmission owners in SPP carry out their transmission planning via a process that is fully integrated (i.e. not separate from) SPP's regional planning process, with SPP collecting local planning criteria from each transmission owner in accordance with its tariff.[271]

Local planning processes may address not only local planning criteria but also project upgrades and replacements. Most RTOs have long-standing processes which exempt end of life projects from the full rigors of the regional planning process and allow incumbent TOs to rebuild, replace or upgrade select assets as they approach the end of their useful life.[272] Non-RTO regions have processes which are more opaque or non-existent, leaving end-of-life project planning entirely to local planning processes that are not subject to the transparency requirements of the regional planning process. In such local planning processes, the opportunity to leverage project upgrades to meet needs beyond the immediate reliability issue may or may not be considered, but are not assessed in the con-

268 *See,* e.g., ISO New-England, *Transmission Planning Assumptions*, September 6, 2017; PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 2.7.2, October 1, 2020; and MISO, *Planning Models Used by MISO*, April 24, 2018.

269 *Monongahela Power Company et al.*, Order on Rehearing and Compliance, 164 FERC ¶ 61,217, at P 13, September 26, 2018.

270 *See* PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 1.1, October 1, 2020 (providing an overview of the PJM transmission planning process).

271 SPP, *Integrated Transmission Planning Manual*, § 4.2.6, July 20, 2017.

272 *See* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 20, April 2019. (noting that all RTOs examined exempt certain upgrade projects from competitive solicitation processes).

text of larger regional needs. Local projects must be coordinated with regional planning entities in advance of being placed in-service per NERC standards, but process simply checks for operational issues, not economic efficiency.

Local projects exempt from regional cost allocation can address a wide range of needs. PJM's supplemental project planning process, for example, may identify any "need associated with a transmission expansion or enhancement not required to comply with the PJM reliability, operational performance, FERC Form No. 715 or economic criteria.[273] MISO's "Other" projects, which comprised the majority of projects included in MTEP19, are driven by a variety of needs including reliability, age and condition, load growth, and other planning needs.[274]

Overall, the dividing line between what constitutes a "local" versus a regional project is murky, and varies significantly by region, as does the extent of interfacing between the local and regional planning processes. Generally speaking, four related factors contribute to whether a project is local or regional: (i) the project's voltage – with low voltage projects being local and higher voltage being more regional in nature; (ii) whether the project is built to address a local transmission owner's reliability criteria, regional or NERC criteria, or to provide economic or public policy benefits; (iii) whether the project involves maintenance or replacement of a transmission owner's system; and (iv) whether the project creates regional benefits.[275] Further, as discussed above, whether a project is "local" or "regional" has different consequences across different regions, as some regions will include local projects within a regional plan but not allocate costs regionally, whereas other regions will simply exclude such projects from regional plans entirely.

C. Economic, public policy, and multi-value planning processes

Regional planning entities are required to study potential transmission expansion projects to reduce congestion and improve grid efficiencies.[276] To do so, RTOs engage in an economic planning process. Economic planning is based on futures which reflect baseline assumptions for key variables like load growth, natural gas prices, resource additions that include projects which are expected to be approved and installed.

273 PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 1.4.1.5, October 1, 2020.

274 MISO, *MTEP19*, at 16, n.d. (showing that 43% of "Other" projects were driven by reliability, 27% by age and condition, 26% by load growth, and 4% by other needs).

275 The D.C. Circuit recently held that if a project creates regional benefits, its costs cannot be allocated solely to the local zone, even where the project is driven solely by local reliability planning criteria. *See Old Dominion Electric Cooperative v. FERC*, 898 F.3d 1254, 1260-64 (D.C. Cir. 2018).

276 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 147, July 21, 2011.

RTOs vary in how they establish the future scenarios, as well as in the planning horizon assessed. Some regions, such as MISO, use the same future scenarios to inform both reliability and economic planning processes,[277] whereas others like PJM vary the assumptions used at the economic planning stage.[278] Generally speaking, the generation and demand profiles used by regions for purposes of economic planning processes reflect known retirements and interconnections rather than reasonable projections of future retirement and interconnection scenarios, with a few limited exceptions.[279] For example, PJM's planning processes include new generation sensitivities in its transmission modeling process only "[w]hen the PJM load in the RTEP model exceeds the sum of the available in-service generation plus generation with an executed [Interconnection Service Agreement]," and they do so by simply "including queued generation that has received an Impact Study" rather than conducting more sophisticated analysis.[280]

While economic planning processes are primarily designed to reduce congestion rather than solve reliability challenges, reliability and economics are interrelated. In many cases, today's economic upgrade addresses tomorrow's reliability need. Economic projects can displace reliability solutions, as long as they pass the same parameters that are being considered for the reliability portfolio. Some planning regions have taken the positive step of using market efficiency planning processes to determine if proposed reliability-based enhancements could have economic benefits if accelerated, or yield greater benefits if modified.[281] But no economic planning process accounts for the full range of reliability benefits that can be provided by economically planned projects.

Beyond this core economic planning process, many regions also have a particularized process to identify projects driven by public policies, or projects driven by a range of factors, including reliability, economic efficiency, and public policies. Needs are assessed according to a range of different metrics, which in many regions depend on the project pathway chosen. Project pathways may be dependent on relatively arbitrary buckets or artificially restrict the potential benefits of solutions to be provided to address transmission needs. For example, MISO has separate processes for Market Efficiency Projects and Multi-Value Projects, despite the fact that in theory Market Efficiency Projects are identified according to a process that incorporates both public policy and reliability needs. Market Efficiency Projects must meet a specified set of cost savings metrics with a BCA ratio

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277 MISO, *Business Practices Manual Transmission Planning*, § 4.4.2.5, effective date: May 1, 2020, (explaining that economic transmission planning solutions are examined according to performance in the "Futures" selected).

278 *See* PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, § 1.3.2, October 1, 2020.

279 MISO's "Futures" process includes a more robust scenario assessment.

280 PJM, *PJM Manual 14B: PJM Region Transmission Planning Process*, Attachment B.4 Scenario Planning Procedure, October 1, 2020.

281 *See*, e.g., PJM, *Regional Transmission Expansion Plan*, at 61, February 29, 2020.

of at least 1.25,[282] whereas Multi-Value Projects must meet one of three criteria that involve (1) reliably and economically delivering energy in support of a state policy mandate; (2) providing multiple types of economic value across multiple pricing zones for a BCA of 1.0 or higher; or (3) address a projected violation of a reliability standard and have a total project BCA of 1.0 or higher.[283] The MISO planning rules are not clear when one project pathway will be pursued to identify solutions versus another, or how exactly identifying transmission needs differs under each process. Neither MISO nor other Planning Authorities have begun Multi-Value processes in the last ten years. This structure of including several different project pathways with a lack of clarity around when each pathway is used is common among RTOs.

D. Inter-regional planning

Order No. 1000 expanded the planning requirements of Order No. 890 to require regional planning entities to establish procedures with each of its neighboring regional planning entities within existing interconnections for the purposes of coordinating and sharing regional plans to identify potential transmission solutions that are more efficient and effective than separate regional solutions to each region's needs.[284] Order No. 1000 specifies that this coordination process must include "a formal procedure to identify and jointly evaluate interregional transmission facilities."[285] It also 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."[286]

While Joint Operating Agreements have been in place for years, the focus has been for model and data exchanges to support operations, not efficient planning. A key challenge in implementing Order No. 1000 has been that the agreements between regional planning entities have a multi-stage process on interregional project approvals that requires any proposed solution to not only emerge from the coordinated interregional process, but also separately secure approvals from each RTO individually. For example, MISO and SPP have a joint planning committee responsible for carrying out a process that may arrive at identified solutions, at which point "each RTO considers the recommended interregional

282 *See* MISO, *Business Practices Manual Transmission Planning*, § 7.4.2, effective date: May 1, 2020.

283 MISO, *Tariff - Attachment FF*, §§ II.C.1, II.C.2, and II.C.3, effective date: August 11, 2020.

284 *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at PP 374-481, July 21, 2011.

285 *Ibid.*, at P 435.

286 *Midcontinent Independent System Operator, Inc., Southwest Power Pool, Inc.*, 168 FERC ¶ 61,018, at P 5, July 16, 2019.

transmission solutions in its respective regional transmission planning process."[287] For a project to be approved it must first "be vetted through both RTO regional processes and approved by each RTO's Board of Directors."[288] Recent reforms have collapsed one stage between these RTOs it is still unlikely for the separate processes to find the same project result from their analyses.

E. Project selection for reliability, economic, public policy, multi-value, and inter-regional projects

Order No. 1000 eliminated the Right of First Refusal for utilities to build regionally and inter-regionally cost-allocated projects. In implementing this directive, the goal of planning entities, at least in theory, is to identify and select the best performing portfolio of projects according to the regional metrics, and approve those projects for regional cost allocation. All regions approach this task by first conducting the reliability and economic needs assessments described above. Some regions follow this by defining with particularity the types of infrastructure that can meet these needs, then using a competitive solicitation process to select projects.[289] Other regions use a "sponsorship model," where transmission providers are invited to propose projects that meet the needs.[290]

In practice, however, competitive solicitation is seldom used. The Commission has approved exclusions for reliability projects if those projects are needed in a short time frame, reasoning that the 6-18 months required to conduct a solicitation makes competition an inappropriate mechanism to select projects to meet those needs.[291] Regions also exclude projects from competition based on voltage level and/or total cost, with lower voltage or smaller sized local projects not subject to competition.[292] The voltage and size thresholds vary widely by region.[293] For example, MISO requires economic efficiency projects selected by competition to have a minimum voltage level of 230kV and $5 million in total costs,[294] while ISO-NE only applies a voltage threshold of less than 100 kV.[295]

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287 *Ibid.*, at P 2.

288 *Ibid.*, at P 3.

289 Joseph H. Eto and Giulia Gallo, *Regional Transmission Planning: A Review of Practices Following FERC Order Nos. 890 and 1000*, at 5-6, November 2017.

290 *Ibid.*, at 5.

291 See Johannes P. Pfeifenberger et al., Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value, at 20, April 2019.

292 *Ibid.*

293 *Ibid.*

294 MISO, *Tariff - Attachment FF*, § II.B, effective date: August 11, 2020.

295 *See* Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 20, April 2019.

These exclusions, along with state Right of First Refusal laws, contributed to the outcome of only 3% of total RTO-region transmission investments being competitively selected between 2013 and 2017, according to the Brattle Group analysis.[296] As Order No. 1000 requires regional cost allocation for regionally beneficial projects that are planned with a long lead time, the lack of competitively selected projects shows that very few projects are being planned with regional needs in mind.

Rather, the dominant trend has been of regional plans composed almost entirely of projects that (i) address local needs and are not designed to provide greater regional economic efficiency or address public policy needs, and (ii) projects built to replace existing infrastructure, executed with short lead time in advance of the reliability need being addressed and accordingly, often without assessing potential synergies with broader regional needs and leveraging the opportunity to build larger or differently designed infrastructure utilizing the right-of-way to more cost-effectively address more regional needs.

MISO's MVP Portfolio included within MTEP11, and SPP's Priority Projects portfolio, approved in 2010, are the two main exceptions to this trend, but both occurred prior to the passage of Order No. 1000.[297] Accordingly, Order No. 1000's requirement for competitive selection did not apply and those broad portfolios consisted of solutions identified by regional planners and implemented by incumbent utilities.

296 *Ibid*., at 18.

297 SPP's 2010 Priority Projects portfolio was spurred by the Synergistic Planning Project Team (SPPT) report which outlined a new transmission planning process as well as a new cost allocation methodology, both of which were ultimately approved. SPP, *SPP Priority Projects Phase II Report*, February 2010. The portfolio consisted of 6 projects including three double-circuit, high capacity 345kV backbone projects in western SPP be approved to address benefit projected Generation Interconnection and Aggregate Transmission Service Study processes, address known and anticipated congestion patterns and also to better integrate the west and east portions of the SPP transmission system. Construction of these projects was projected to result in large local economic benefits.

MISO provides a paradigmatic example of the near exclusive reliance on locally planned projects and projects exclusively focused on reliability since Order No. 1000 was implemented:

TABLE 2 MISO MTEP Investment by Project Type[298]

YEAR	BASELINE RELIABILITY PROJECTS (BRP) ($ MILLION)	MARKET EFFICIENCY PROJECTS (MEP) ($ MILLION)	MULTI-VALUE PROJECTS (MVP) ($ MILLION)	OTHER (LOCAL) ($ MILLION)
2010	94	-	510	575
2011	424	-	5,100	681
2012	468	15	-	744
2013	372	-	-	1,100
2014	270	-	-	1,500
2015	1,200	67	-	1,380
2016	691	108	-	1,750
2017	957	130	-	1,400
2018	709	-	-	2,300
2019	836	-	-	2,800

Likewise, in PJM, about two thirds of projects were Supplemental Projects planned outside the regional process, 75 percent of which were driven by end-of-life planning decisions.[299]

F. Overall assessment of the current approach

The lack of regionally planned projects should not be taken as evidence that such planning would not yield benefits. Experience with MISO's MVP portfolio and SPP's priority projects portfolio has shown that, where proactive planning has been utilized, the resulting projects have been highly beneficial with total benefits approximately three times

298 Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, *Section 206 Complaint and Request for Fast Track Processing*, at 31-32, January 21, 2020.

299 Paul L. Joskow, *Competition for Electric Transmission projects in the U.S.: FERC Order 1000*, March 2019; and Mohammad Reza Hesamzadeh, Juan Rosellon, and Ingo Vogelsang, *Transmission Network Investment in Liberalized Power Markets*, Springer 2020. *See also* PJM Interconnection, L.L.C., *Affidavit of Johannes P. Pfeifenberger and John Michael Hagerty on Behalf of LS Power*, Docket No. ER20-2308, at 7, July 23, 2020.

larger than costs.[300]

And as discussed in Appendix A, studies from National Labs and other sources suggest that benefits of more regionally planned projects would greatly exceed costs, and the backlog of projects in the interconnection queue suggest that more transmission planned to resource rich regions would eliminate costly delays and provide customers with access to lower cost supply.

Rather than reflecting their lack of net benefits, the lack of proactively planned projects is the result of shortcomings in regional planning processes, cost allocation, governance and oversight. Regional planning processes suffer from four primary deficiencies. First, many regional plans identify transmission needs through a siloed process that considers reliability, economic, and public policy benefits separately, rather than looking at all needs holistically. Second, in identifying transmission needs, regional planning entities generally rely upon modeling that does not accurately forecast future supply mixes or electricity demand. Third, regional processes used for identifying solutions to transmission needs do not include the full range of technologies available to serve needs. Fourth, benefit-cost analyses applied to regional transmission projects generally do not accurately reflect the full range of project benefits or select the option that maximizes aggregate net benefits to consumers.

By remedying these deficiencies, together with overcoming shortcomings in cost allocation, governance, and oversight processes discussed in Sections IV and V, the Commission can create a process through which regional planning processes more cost-effectively meet future needs and result in just and reasonable rates.

300 MISO now projects to create average monthly benefits between $4.23 and $5.13 for the average residential customers over the next 40-year period, as compared to only $1.50 per month in average costs. MISO, *MTEP19*, at 7, n.d. SPP found $3.4 billion in transmission upgrades it installed between 2012 and 2014 created over $16 billion in gross savings – 3.5 times greater than the cost of the transmission upgrades. SPP, *The Value of Transmission*, January 26, 2016.

EXHIBIT 2

January 2021

Americans for a Clean Energy Grid

DISCONNECTED: THE NEED FOR A NEW GENERATOR INTERCONNECTION POLICY

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About Americans for a Clean Energy Grid

Americans for a Clean Energy Grid (ACEG) is the only non-profit broad-based public interest advocacy coalition focused on the need to expand, integrate, and modernize the North American high voltage grid.

Expanded high voltage transmission will make America's electric grid more affordable, reliable, and sustainable and allow America to tap all economic energy resources, overcome system management challenges, and create thousands of well-compensated jobs. But an insular, outdated and often short-sighted regional transmission planning and permitting system stands in the way of achieving those goals.

ACEG brings together the diverse support for an expanded and modernized grid from business, labor, consumer and environmental groups, and other transmission supporters to educate policymakers and key opinion leaders to support policy which recognizes the benefits of a robust transmission grid.

About the Macro Grid Initiative

The Macro Grid Initiative is a joint effort of the American Council on Renewable Energy and Americans for a Clean Energy Grid to promote investment in a 21st century transmission infrastructure that enhances reliability, improves efficiency and delivers more low-cost clean energy. The Initiative works closely with the American Wind Energy Association, the Solar Energy Industries Association, the Advanced Power Alliance and the Clean Grid Alliance to advance our shared goals.

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I. Executive Summary

America's system for planning and paying for the nation's transmission grid is causing a massive backlog and delay in the construction of new power projects. While locally produced electric power is gaining in popularity, most of the lowest cost new power production comes from projects which are located in rural areas and, thus, depend on new electricity lines to deliver power to the urban and suburban areas which use most of the nation's power. Project developers must apply for interconnection to the transmission network, and until the network capacity is expanded to accommodate the resources, the projects must wait in an "interconnection queue." At the end of 2019, 734 gigawatts of proposed generation were waiting in interconnection queues nationwide.[1]

This massive backlog has multiple negative impacts on the nation. First, it needlessly increases electricity costs for America's homes and businesses in two ways: (1) it slows or prevents the adoption of new power sources which are cheaper than existing power generation; and (2) it also significantly increases the costs of each new power source. Americans for a Clean Energy Grid's (ACEG) recent study demonstrates that a comprehensive approach to building transmission to connect remote power resources to electricity load centers in the Eastern half of the U.S. can cut consumers electric bills by $100 billion and decrease the average electric bill rate by more than one-third, from over 9 cents/kWh today to around 6 cents/kWh by 2050,

[1] Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. *See* also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

Key Findings

- The current system for planning and paying for expansion of the transmission grid is so unworkable and inefficient it is creating a huge backlog of unbuilt energy projects. At the end of 2019, 734 gigawatts of proposed generation were waiting in interconnection queues nationwide.
- This backlog is needlessly increasing electricity costs for consumers by delaying the construction of new projects which are cheaper than existing electricity production.
- Because most of these projects are located in remote rural areas, this backlog is harming rural economic development and job creation.
- Almost 90 percent of the backlog is for wind, solar, and storage projects. The backlog may delay or prevent achievement of commitments that states, utilities, and Fortune 500 companies have made to scale up their renewable energy use or reduce their pollution.
- The risk from the uncertainty of the interconnection process significantly increases the cost of capital for generation developers, which increases the cost of energy for customers.
- Although Regional Transmission Orginizations (RTOs) and the Federal Energy Regulatory Commission (FERC) have undertaken worthwhile attempts to alleviate interconnection backlogs, the interconnection queues remain costly, lengthy, and unpredictable.
- The current "participant funding "policy that places nearly all costs of shared large network upgrades on the interconnection customer violates FERC's "beneficiary pays" principle and is therefore no longer a "just and reasonable" policy and violates the Federal Power Act.

Key Recommendations

» FERC should discontinue the policy of participant funding for new generation. Shared network upgrades resulting from generation interconnection requests provide economic and reliability benefits to loads and reduce congestion to improve grid efficiencies and operational flexibility, and therefore should not be fully assigned to interconnection generators.

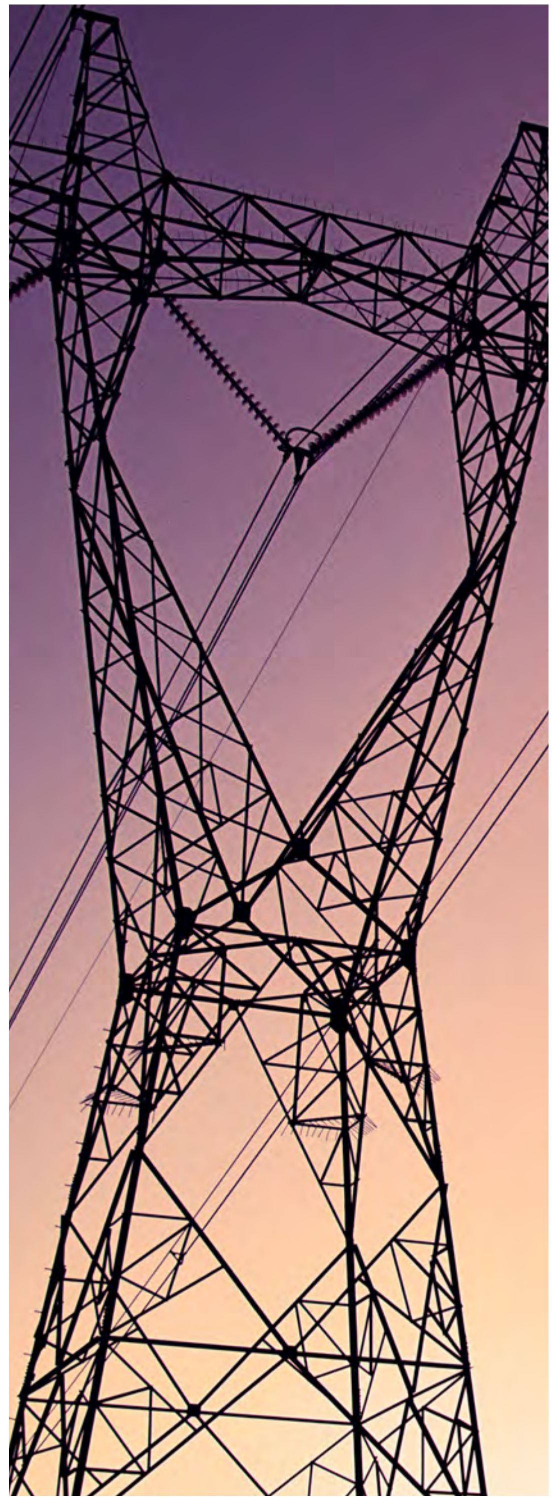
» FERC and planning authorities should expand and improve regional and inter-regional transmission planning processes to be pro-active, incorporating future generation additions and retirements and the multiple benefits, and spread costs to all beneficiaries.

saving a typical household more than $300 per year.[2]

Second, because the lowest cost proposed power projects are often located in rural areas, this backlog is blocking rural economic development and job creation. In addition, rural power projects expand the tax base of local communities and typically generate lease payments or other revenue for farmers and other landowners. New transmission in the Eastern half of the U.S. alone will unleash up to $7.8 trillion in investment in rural America and create more than 6 million net new domestic jobs.[3]

Third, almost 90 percent of the backlog is for wind and solar projects, thus blocking the resources which dominate new electricity production, reflecting the changing resource mix in the power sector and America's abundance of high-quality renewable resource areas where the sun shines bright and the wind blows strong.[4] The U.S. Energy Information Administration (EIA) projects wind and solar will account for 75 percent of new electricity generation in 2020.[5] Many states, utilities, Fortune 500 companies and other institutions have adopted large commitments or requirements to scale up their renewable energy use or reduce their carbon pollution and this backlog may delay or impede achievement of these commitments or requirements. In addition, delays in developing these projects unnecessarily exposes Americans, especially those in environmental justice communities, to the harmful impacts of smog, and nitrogen oxide, sulfur dioxide, fine particulate and carbon dioxide pollution.

Policies governing the interconnection of generators to the grid network stand in the way of accessing these remote resources. Interconnection policies and procedures governing transmission engineering studies, queuing, and allocating transmission upgrade costs are set by the Federal Energy Regulatory Commission (FERC) and implemented in



2 Christopher T.M. Clack et al., *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.*, October 2020.

3 *Id.*

4 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. *See* also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

5 U.S. Energy Information Administration, *New Electric Generating Capacity in 2020 Will Come Primarily From Wind and Solar*, January 14, 2020.

detail by all of the hundreds of transmission providers around the country including the Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).[6]

Although FERC and the RTOs have undertaken worthwhile reforms to alleviate interconnection backlogs, the interconnection queues are costly, lengthy, and unpredictable. Power project developers are uncertain if their project will be approved and this risk significantly increases the cost of capital for generation developers, which increases the cost of energy for customers.

The current process also places nearly all costs of network upgrades on the energy project developer, even though many others will benefit from the construction of the project. Until a few years ago, these interconnection charges for new renewable resources would comprise under 10 percent of the total project cost for most projects. In recent years - due to the lack of sufficient large-scale transmission build - these costs have dramatically risen and interconnection charges now can comprise as much as 50 to 100 percent of the generation project costs. The system has reached a breaking point recently as spare transmission has been used up. Presently in most regions, new network capacity is needed for almost all of the projects in the queues.

Participant funding for new grid connections is no longer a "just and reasonable" policy and violates FERC's "beneficiary pays" principle and the Federal Power Act. Relying on the interconnection process to identify needed transmission leads to a piecemeal approach and inefficiently small upgrades, raising costs to consumers. The incremental reforms at the RTO-level over the past decade have only served to treat symptoms of this fundamental issue – the lack of alignment between regional planning processes and the interconnection process.

There is a better way. RTOs could conduct comprehensive transmission planning which would identify the transmission lines to connect many new energy projects to the grid and deliver the greatest benefits for consumers. It is time for FERC and RTOs to undertake a fundamental re-thinking of interconnection and transmission planning policy based on different circumstances than those that existed when these policies were developed. Full participant funding should no longer be allowed in RTO or non-RTO areas.

More broadly, FERC and RTOs should pursue planning reforms. Consumers would benefit from more efficient transmission at a scale that brings down the total delivered cost, rather than continuing the current cycle of incremental transmission built in the project-by-project or generator-only cost assignment regime. That shift will not happen in the current interconnection process. Instead, FERC should fundamentally reform the regional and inter-regional transmission planning process to require broader pro-active and multi-purpose transmission planning.

This paper is structured as follows:

- Section II explains the origin of current interconnection policy;
- Section III describes implications of a different set of resources than those for which the policies were designed;
- Section IV provides evidence that the current policy no longer works for the current mix;
- Section V describes incremental solutions to those problems;
- Section VI argues that the real solution must involve broader transmission planning reform; and
- Section VII concludes.

[6] Throughout this paper, we refer to RTOs and ISOs together simply as "RTOs."

II. Interconnection Queue Policy Inherited from a Bygone Era

Generator interconnection policy was established two decades ago when almost all new interconnecting generators were natural gas-fired. Gas generators can interconnect with transmission systems in a relatively wide variety of locations, allowing them to avoid transmission constraints. As a result, transmission planning is less important with gas generation, as locational wholesale market prices and network upgrade costs assigned to interconnecting generators are able to direct gas generation investment to economically efficient locations.

Our current interconnection policies are an increasingly obsolete vestige of that era. FERC Order No. 2003, issued in the year 2003, standardized Large Generator Interconnection Procedures (LGIPs) and Large Generator Interconnection Agreements (LGIAs). As part of the Order, FERC determined that RTOs may propose that interconnecting generators be solely responsible for paying for Generation Interconnection (GI) network upgrades—a cost allocation policy referred to as "participant funding."[7] The Commission reasoned that "…under the right circumstances, a well-designed and independently administered participant funding policy for Network Upgrades offers the potential to provide more efficient price signals and a more equitable allocation of costs than [a] crediting approach."[8] The policy also included a serial approach to interconnection, wherein each generator was reviewed independently for its own impacts on the network in the order they enter the interconnection queue. The Commission's participant funding policy applied only to RTOs and not to utilities non-RTO areas.

That policy of a generator-by-generator transmission planning process and individual assignment of network upgrade costs worked reasonably well for the gas generation additions of the early 2000s. A whopping 191,745 megawatts (MW) of natural gas capacity was added between 2000 and 2005,

7 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 28, July 24, 2003. *Transmission Planning and Cost Allocation by Transmission Owing and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 715, July 21, 2011 (defining "participant funding").

8 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 695, July 24, 2003.

compared to 23,434 MW for the entire decade from 2010-2019.[9] After that gas generation boom, the resource mix of new interconnecting generators changed as interest in renewable energy grew among states and customers and the costs of utility-scale wind and solar projects continued to decline. Utility-scale wind and solar projects have dominated generating capacity additions over the last decade, with around 100,000 MW added, and they are expected to account for an even larger share of capacity additions going forward.

The transmission policy embodied in FERC Order 2003 that provided efficient incentives for the siting of gas generation has proven inefficient and unworkable for today's resource mix. Wind, and to a lesser extent solar generation, is heavily location-constrained, unlike gas generation. Wind turbines located near the best wind resources are several times more productive than wind turbines at a typical site selected at random, while the best solar resource sites are about twice as productive as less optimal sites, corresponding to a proportional impact on the cost of energy from renewable energy resources. Wind and solar are also scalable and benefit from economies of scale, so most projects are large and built in remote areas where large amounts of land are available at low cost.[10] As a result, these renewable projects often require larger transmission upgrades to serve load.

As wind capacity grew in the late 2000s, interconnection queues became overloaded in certain areas. When transmission capacity extending to good wind resource areas reached capacity, large network upgrade costs would be assigned to the next wind projects entering the queue. When these wind project owners saw the hefty price tag and the difference between what they were paying compared to their competitors that might have been just ahead of them or behind them in the queue, they would often drop out of the queue. Often one project would be assigned a high cost to upgrade the network, but then subsequent projects could utilize the capacity that project created, such that the subsequent project would be assigned a lower cost. When one project drops out, costs are typically shifted onto others, causing a domino effect of cancellations. Project developers, knowing there was a chance of getting lucky with a lower network upgrade cost assignment, had an incentive to enter multiple project proposals and multiple locations. Thus, many projects would enter queues, and many projects would cancel, leading to a cycle of continuous churn. RTOs are required to study all projects, leading to lengthy workloads and inevitable delays.

Over the years FERC and RTOs have noticed the problem and attempted to fix it with process changes. In 2008, FERC held a technical conference to discuss interconnection queue-related issues that arose after Order No. 2003, and issued an Order directing RTOs to develop solutions to address queue delays and backlogs.[11] RTOs held numerous interconnection queue reform stakeholder processes, many resulting in FERC filings and tariff changes. Some of these incremental reforms, as described in more detail below, helped to reduce the churn and the quantities of projects backlogged in the queue. MISO stakeholder fora such as the Interconnection Process Task Force and the Planning Advisory Committee, for example, developed a series of queue reforms between 2008 and 2012 to address queue delays and project cancellations.[12] In 2016, MISO proposed tariff revisions to minimize restudies and introduced new milestones to improve project readiness, among other revisions to improve process efficiency.[13] MISO later built upon these reforms in 2018 to reduce cancellations and logjams by eliminating fully refundable milestone payments and requiring site control demonstration.[14]

SPP, like MISO, experienced high renewable energy interconnection interest in the late 2000s and reformed its interconnection process to transition to an approach that discouraged speculative projects

9 Headwaters Economics, *U.S. Generation Capacity, 1950-2030*, Updated April 2020.

10 American Wind Energy Association, *Grid Vision: The Electric Highway to a 21st Century Economy*, at 30-42, May 2019.

11 *Interconnection Queuing Practices*, 122 FERC ¶ 61,252, March 20, 2008.

12 MISO, *Filing of Revisions to the Open Access Transmission, Energy and Operating Reserve Markets Tariff to Reform MISO's Generator Interconnection Procedures*, at 5-6, December 31, 2015.

13 *Id.* at 3-4.

14 Jasmin Melvin, *FERC Clears MISO Interconnection Reforms Targeting Recent Influx in Speculative Projects*, December 4, 2019.

from proceeding through the queue. These reforms included a "first-ready, first served" policy and a greater use of cluster interconnection studies, among other measures.[15] In 2013, SPP further increased milestone requirements and required generators to post a financial milestone upon execution of a Generator Interconnection Agreement (GIA),[16] and in 2019 further refined its interconnection process to include a three-stage study process with financial deposits required at each stage.[17]

As renewable energy expanded into the Mid-Atlantic states in the 2010s, PJM began facing the same challenges. In 2012, FERC accepted PJM tariff modifications selected by the PJM Interconnection Process Senior Task Force, which among other changes, extended the length of the queue cluster to avoid queue study overlap and associated restudies.[18] The reforms also included an alternate queue for the hundreds of projects under 20 MW that were observed to drop out at higher rates and trigger constant restudies.

California proceeded down a similar policy evolution as MISO, SPP, and PJM. After transitioning to a cluster approach in 2008 and creating requirements to demonstrate project viability,[19] CAISO filed tariff revisions in 2010 to combine its small and large generator interconnection procedures in an attempt to streamline the processes.[20] Citing an increase in renewable generator interconnection requests due to renewable portfolio standards and related dropouts, CAISO later filed additional revisions in 2012 to integrate the transmission planning process and generation interconnection procedures.[21] In 2013, CAISO launched its first Interconnection Process Enhancement initiative, a stakeholder process to improve interconnection procedures.[22]

Despite these various incremental reforms at the RTO level, however, the fundamental problem driving the queue backlog, a reliance on participant funding and individual generators to build a large share of needed transmission upgrades, remains in place. The share of location-constrained relative to location-flexible generation continued rising through the 2010s, and increasingly affected solar generation as well as wind. Multiple RTOs continue to tinker with reforms to generator interconnection queue processes.[23]

FERC also acted again in 2016 by holding another technical conference[24] on generator interconnection issues partially in response to a 2015 request of formal rulemaking from the American Wind Energy Association to revise FERC's proforma LGIP and LGIAs.[25] The Commission later issued Order No. 845 in 2018,[26] which addressed queue interconnection procedure issues by revising FERC's pro forma LGIP and LGIA's to implement ten specific reforms. The Order was followed up by Order No. 845-A in 2019,[27] which left Order No. 845's major reforms intact, but amended the LGIP and LGIA in an attempt to further improve interconnection processes.

15 *Southwest Power Pool, Inc.*, 167 FERC ¶ 61,275, at P 4, June 28, 2019.

16 *Id.* at P 5.

17 *Id.* at P 11-13.

18 *PJM Interconnection L.L.C. Filing Via eTariff*, at 5, February 29, 2012.

19 K. Porter, S. Fink, C. Mudd, and J. DeCesaro, *Generation Interconnection Policies and Wind Power: A Discussion of Issues, Problems, and Potential Solutions*, at 28, January 2009.

20 *California Independent System Operator Corporation*, 140 FERC ¶ 61,070, at P 3, July 24, 2012.

21 *Id.*

22 *Reform of Generator Interconnection Procedures and Agreements*, Docket No. RM17-8, at 4, April 13, 2017.

23 MISO, for example, recently created the Coordinated Planning Process Task Team in November of 2019 to examine how MISO can better coordinate the separate studies underlying the generator interconnection process and the MISO transmission expansion plan. See Amanda Durish Cook, *MISO Floats Ideas on MTEP, Interconnection Coupling*, May 17, 2020. PJM is in the midst of holding interconnection process workshops to explore potential queue reforms that would allow for more renewable and storage resources to interconnect. See PJM, *Update: Interconnection Process Workshop Dates Announced*, October 6, 2020.

24 *Transcript of FERC Technical Conference on Generator Interconnection Agreements and Procedures and the American Wind Energy Association*, Docket No. RM16-12, May 13, 2016.

25 *Petition for Rulemaking of the American Wind Energy Association to Revise Generator Interconnection Rules and Procedures*, Docket No RM15-21-000, June 19, 2015.

26 *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043, April 19, 2018.

27 *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845-A, 166 FERC ¶ 61,137, February 21, 2019.

III. Implications of a Different Resource Mix

Interconnection policy must work for the resource being interconnected, and the resource mix is clearly changing.[28] Regardless of climate or clean energy policies, renewable energy growth is nearly certain because the costs of renewables have fallen so much to make them competitive with any other resource. Wind and solar energy costs have fallen 70 and 89 percent, respectively, in the last ten years, from 2009 through 2019.[29] As a result of falling costs, consumer preferences, and public policies, wind and solar resources now make up the majority of resources in interconnection queues across the country.[30] 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.[31] In 2019 alone, 168 GW of solar and 64 GW of wind projects entered interconnection queues, as shown in figure 1. The U.S. EIA forecasts that wind and solar will make up over 75 percent of new capacity additions in 2020.[32]

When an increasing amount of location-constrained generation applies for interconnection in the same area, the grid begins to require not only "driveway" type transmission facilities, but also bigger roads and highways. Much like a new community of homes requires a webwork of larger roads to connect to neighboring towns, a more regional network is needed for the U.S. power system. What we are observing is that interconnection studies for individual generators (or groups of generators) are increasingly identifying costly regional upgrades. This is a predictable dynamic.

The future resource mix is made up increasingly of wind and solar energy, which are location-constrained, so it is quite predictable that larger regional network upgrades will be identified in the interconnection processes. Unfortunately, large system upgrades are not efficiently planned or paid for by the interconnection process, which relies on generator-by-generator assessments and participant

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28 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. See also underlying data in the *2020 Wind Energy Technology Data* Update accompanying the slide deck.

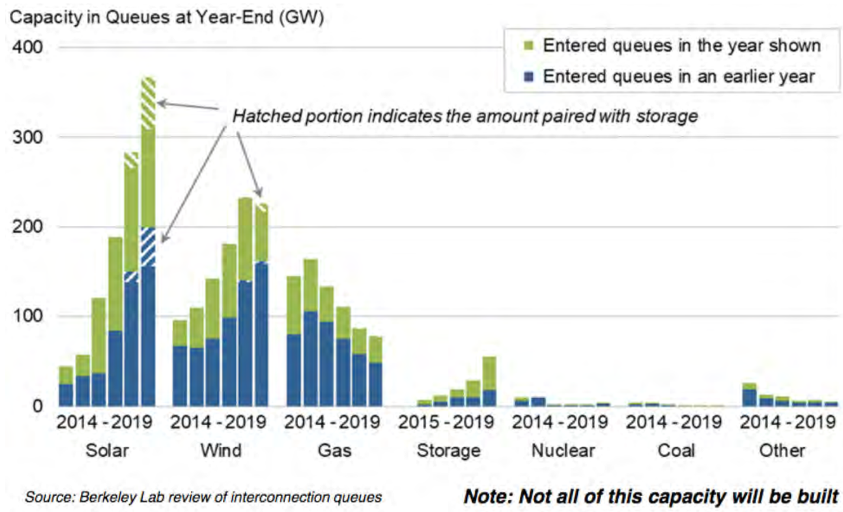
29 Lazard, Lazard's *Levelized Cost of Energy Analysis - Version 13.0*, a 8, November 2019.

30 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

31 *Id.*

32 U.S. Energy Information Administration, *New Electric Generating Capacity in 2020 Will Come Primarily From Wind and Solar*, January 14, 2020.

Figure 1: Capacity in Queues at Year-End by Resource Type



funding for network upgrades. Interconnection costs are governed by Order No. 2003, which established the "at or beyond rule," pursuant to which the costs of facilities and equipment that lie between the generation source and the point of interconnection with the transmission network are borne by the incoming generator.[33] While Order No. 2003 set a default rule that transmission owners would cover the cost of "network upgrades," (equipment "at or beyond" the point of interconnection), it gave RTOs "flexibility to customize . . . interconnection procedures and agreements to meet regional needs."[34] Some RTOs have since adopted methodologies that place the lion's share of network costs on the interconnecting generator.[35]

The current interconnection process simply does not work well when there is not adequate regional transmission capacity or a functioning mechanism to plan and pay for regional transmission. Without transmission planning reform that links the interconnection and regional transmission planning processes and eliminates the use of participant funding for significant system upgrades in the interconnection process, interconnection processes will become mired in ever-longer delays. This problem could potentially be addressed by broader transmission planning reform to support holistic, proactive planning processes in conjunction with accompanying narrow Order No. 2003 reform eliminating participant funding.

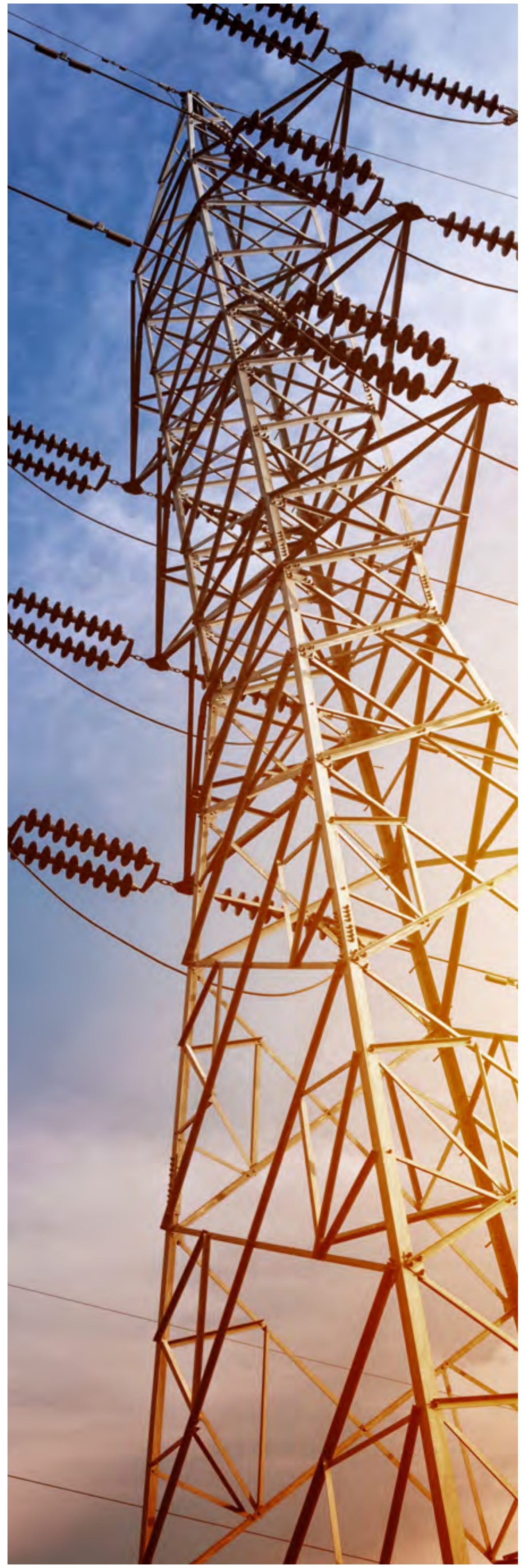
33 See *Ameren Services Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018).

34 *Id.*

35 For example, MISO adopted a methodology allocating 90 percent of even network upgrades above 345 kV to generation owners, and requiring generation owners to pay 100 percent of such costs for lines below 345 kV. See *Ameren Services Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018).

The current process also misses opportunities to design new infrastructure in a more cost-effective fashion and of sufficient scale that maximizes all benefits of transmission, including reliability and economic benefits, and accommodates all likely new generation rather than just the particular generator(s) supporting the upgrades. Given the broad benefits of large-scale regional transmission, it is a violation of FERC's "beneficiary pays" principle to place all the costs of large network upgrades on the interconnection customer. It is clear that the large upgrades being identified and assigned to generators in interconnection studies would provide benefits to users across the network, even if those may be difficult to quantify with certainty. FERC Commissioner LaFleur noted the challenges with the siloed study processes when she commented "...where does the interconnection process leave off and the transmission planning process start?"[36]

Transmission expansion planning for generator interconnections based on generator-by-generator assessments will not result in optimal plans as the resource mix continues to change. Moving to studying clusters of generators simultaneously, as some areas have done, is a step in the right direction. However, current cluster approaches are still based only on what is in the current queue rather than well-known information about what generation is coming and where it is likely to be, and still does not account for the economic and reliability benefits of the transmission expansion.



36 *See* transcript of FERC technical conference in the matter of *Review of Generator Interconnection Agreements and Procedures*, Docket No. RM16-12, at 47, May 13, 2020.

IV. Evidence of a Broken Interconnection Policy

a) Upgrade costs assigned to customers are high

Analysis by Lawrence Berkeley National Laboratory, shown in tables 1 and 2 below, indicates that the costs to integrate new resources, not just renewable projects, have reached levels that are unreasonably high for a developer to proceed in MISO and PJM. As expected, the costs for integrating new resources in MISO are rising substantially relative to previous years, indicating that the large-scale network has reached its capacity and needs to expand to connect more generation. In other words, much more than "driveway" type facilities are needed; larger roads and highways are required to alleviate the traffic. Table 1[37] below shows that historically, interconnecting wind projects have incurred interconnection costs of $0.85 per megawatt hour (MWh) or $66 per kilowatt (kW). However, newly proposed wind projects now face interconnection costs that are nearly five times higher, at $4.05/MWh or $317/kW. For reference, this is about 23 percent of the capital cost of building a wind project.

Table 1: MISO Interconnection Costs for Selected Utility-Scale Projects (as of 2018)

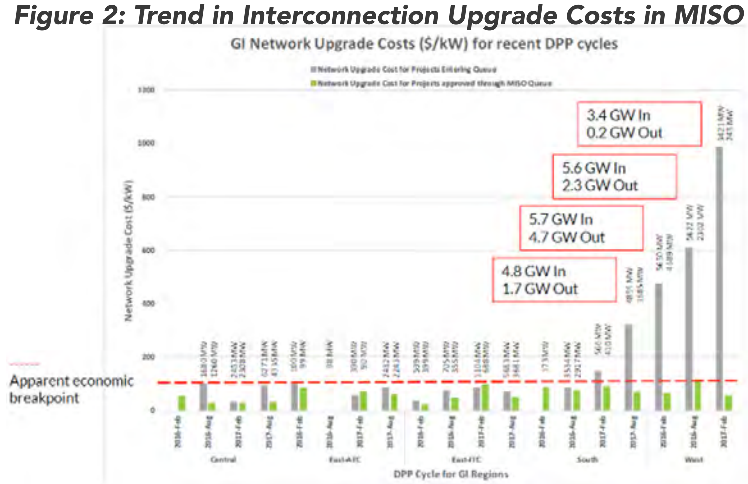
				Unit Cost ($/kW)			Levelized ($/MWh)		
Generator Type	**Projects**	**Costs ($2018 B)**	**MW**	**Overall**	**Constructed Projects**	**Proposed Projects**	**Overall**	**Constructed Projects**	**Proposed Projects**
Natural Gas	55	$0.55	14,642	$38	$31	$55	$0.34	$0.28	$0.50
Wind	161	$4.51	23,232	$194	$66	$317	$2.48	$0.85	$4.05
Solar	33	$0.18	3,277	$56	$70	$53	$1.56	$1.95	$1.48
Coal	19	$0.01	2,991	$4	$4	NA	$0.03	$0.03	NA
Hydro	13	$0.06	4,234	$13	$13	NA	$0.18	$0.18	NA

[37] Will Gorman, Andrew Mills, and Ryan Wiser, *Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy*, at 10, October 2019.

New solar projects in MISO South have much higher upgrade costs. The most recent 2019 system impact study for solar projects in MISO South estimated upgrade costs to total $307/kW, with upgrade costs for individual interconnection requests as high as $677/kW.[38]

The rapidly increasing cost of interconnection in recent years shows that the breaking point has been reached. MISO, for example, has reported that "...interconnection studies for new generation resources in MISO's West sub-region have indicated the need for network upgrades exceeding $3 billion to accommodate the initial queue volume, and a similar trend is expected to occur in other areas with high wind and solar potential, including MISO's Central and South sub-regions."[39] Figure 2[40] below illustrates the large increase in assigned network upgrade costs to generators in MISO West, from approximately $300/kW in 2016 to nearly $1,000/kW in 2017. The costs to build proposed wind projects will likely result in developers abandoning those resources as project integration costs exceed $100/kW.

Figure 2: Trend in Interconnection Upgrade Costs in MISO



The same trend of rising network upgrade cost assignments is occurring in PJM. Historically, the levelized costs for constructed wind and solar projects were $0.25/MWh and $1.72/MWh, respectively, or $19.07 kW and $61.83/kW, respectively. As shown in Table 2,[41] upgrade costs for newly proposed wind and solar projects, however, have now risen to $0.69/MWh and $3.66/MWh, respectively, or $54/kW and $131.90/kW, respectively – more than a 100 percent increase.

Table 2: PJM Interconnection Costs for Selected Utility-Scale Projects (as of 2019)

				Unit Cost ($/kW)			Levelized ($/MWh)		
Generator Type	Projects	Costs ($2018 B)	MW	Overall	Constructed Projects	Proposed Projects	Overall	Constructed Projects	Proposed Projects
Natural Gas	98	$1.43	38,733	$36.92	$18.40	$76.63	$0.34	$0.17	$0.70
Wind	72	$0.25	10,859	$22.73	$19.07	$54.10	$0.30	$0.25	$0.69
Solar	134	$1.17	10,057	$116.17	$61.83	$131.90	$3.22	$1.72	$3.66
Coal	4	$0.05	1,303	$36.26	$36.26	NA	$0.25	$0.25	NA
Nuclear	2	$0.03	1,674	$19.63	$19.63	NA	$0.12	$0.12	NA

38 MISO, *Final MISO DPP 2019 Cycle 1 South Area Study Phase I Report*, at 8-15, July 16, 2020.

39 MISO, *MISO 2020 Interconnection Queue Outlook*, at 9, May 2020.

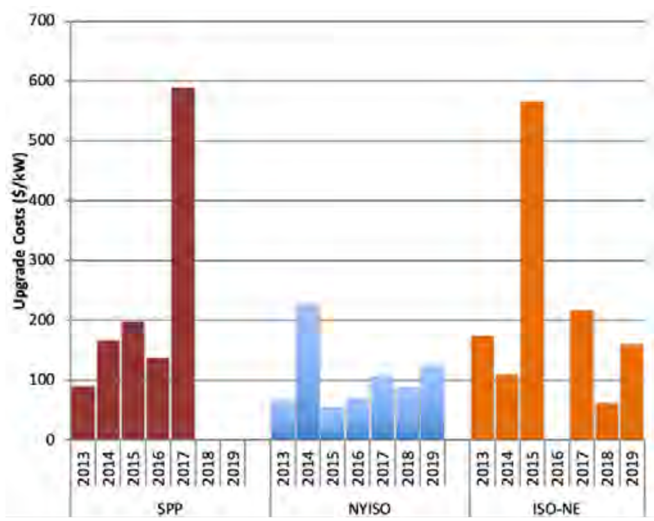
40 ITC, *MISO Generation Queue and Renewable Generation: Update to the Advisory Committee*, at 5, May 20, 2020.

41 Will Gorman, Andrew Mills, and Ryan Wiser, *Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy*, at 12, October 2019.

In 2019, one 120 MW solar plus storage project in southern Virginia was informed it could be required to pay as much as $1.5 billion, or $12,086/kW, in system upgrades in order to connect to the PJM grid.[42] Among the many upgrade costs associated with the GI request includes the demolition and rebuilding of a handful of 500kV lines.[43] The construction of large transmission lines required by some interconnection studies which leads to such high network upgrade costs are not isolated incidents. A number of offshore wind projects in PJM, for example, are expected to build long, 500kV lines that are clearly network elements that benefit the entire region and should be planned and paid for through the regional planning process.[44]

This trend of rising network upgrade costs is happening across RTOs as the ratio of location-constrained generation rises and the existing network in the renewable resource areas becomes constrained. The typical increase in costs over time associated with GI studies, as shown in Figure 3[45] below, are indicative that the assigned network upgrades are high enough that most projects will not proceed.

Figure 3: Trend in Generator Interconnection Network Upgrade Costs in SPP, NYISO, and ISO-NE ($/kW)



In SPP, GI-assigned network upgrade costs from the 2013 interconnection queue were roughly $89/kW while the most recent 2017 study costs approached $600/kW. Put differently, network upgrade costs increase from composing around 8 percent of the capital cost of wind generation, to over 43 percent.[46] The most recent 2017 SPP study upgrade costs included massive 765kV lines up to 165 miles long.[47]

42 PJM, *Generation Interconnection Feasibility Study Report for Queue Project AE1-135*, at 6, January 2019.

43 *Id.* at 18.

44 *See* PJM, *Generator Interconnection Feasibility Study Report for Queue Project AF2-193*, at 15, Revised August 2020; PJM, *Generation Interconnection Impact Study Report for Queue Project AE2-251*, at 58, February 2020; PJM, *Generation Interconnection Impact Study Report for Queue Project AE2-122*, at 28, February 2020.

45 *See* publicly available SPP, *Generator Interconnection Studies* (note that SPP is behind in processing impact studies). NYISO and ISO-NE generator interconnection studies are not available to the public and require a Critical Energy Infrastructure Information (CEII) non-disclosure agreement with the ISOs.

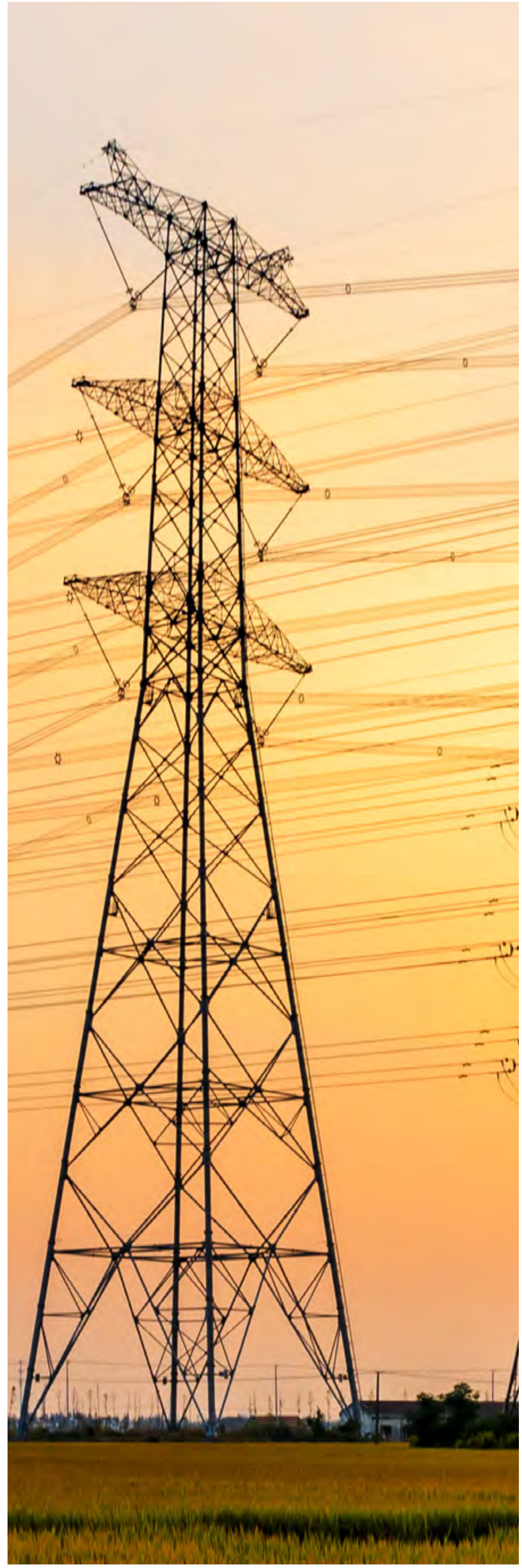
46 In 2019, installed wind power project costs were approximately $1,387/kW in the region that includes most of SPP and MISO. We use the range of network cost increases from SPP generator interconnection studies and the aforementioned cost of installed wind power projects to estimate network upgrade costs as a share of the cost of generation in 2013/2014 vs. 2016. See Ryan Wiser et al., *Wind Energy Technology Data Update: 2020* Edition, at 56, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

47 *See* tab titled "Assigned Upgrade Costs" in SPP *DISIS-2017-001 Phase One*, Revised, November 11, 2020.

NYISO has also experienced an increase in upgrade costs from $67/kW in 2013 to $124/kW in 2019. Experience in ISO-NE on the other hand, while not a linear display of upgrade cost increases, demonstrates how high the network upgrade costs can get in any given year with 2015 upgrade costs reaching $566/kWs. Upgrade costs for ISO-NE also increased by 160 percent from 2018 to 2019.

b) Paying for transmission through the interconnection process fails to capture efficiencies that benefit all users

The system of funding major transmission upgrades through the generation interconnection process is ineffective and violates the beneficiaries pays principle. Large new transmission additions create broad-based regional benefits by providing customers with more affordable and reliable power, so charging only interconnecting generators for this equipment requires them to fund infrastructure that benefits others. MISO, for example, has estimated that its 17 Multi-Value Projects (MVPs) approved in 2011 will generate between $7.3 to $39 billion in net benefits over the next 20 to 40 years, producing cost-to-benefit ratios ranging from 1.8 to 3.1.[48] Additionally, SPP's portfolio of transmission projects constructed between 2012 and 2014 is estimated to generate upwards of $12 billion in net benefits over the next 40 years, with a cost-to-benefit ratio of 3.5.[49] Charging only interconnecting generators for the construction of transmission additions that generate benefits similar to those found in MISO and SPP is a classic example of the "free rider" problem. This type of market failure found in various other economic sectors involving networks, such as water and sewage systems and highways, signals why it is more efficient to broadly allocate the cost of "public goods." If required to pay for upgrades that mostly benefit others, interconnecting generators tend to balk and drop out of the interconnection queue.



c) Interconnection queue project cancellations are rising

The interconnection process relies upon sequential studies that are highly unpredictable for participating generators who do not know whether their interconnection request

[48] MISO, *MTEP19*, at 6-7, n.d.

[49] SPP, *The Value of Transmission*, at 5, January 26, 2016.

will require large upgrades. The uncertainty of interconnection costs leads wind and solar developers to often submit multiple interconnection applications for the same generator, typically for different project sizes, configurations, and interconnection points, which leads to a queue with far more projects than will actually be developed. This is a rational strategy from the developer's perspective; however, the proliferation of projects only exacerbates the number of re-studies and the number of uncertainties that can affect every project. When studies reveal significant costs, those projects tend to drop out of the process, necessitating restudies for all remaining generators and prompting delays (and often higher costs) for projects that are part of the same interconnection class year or further down in the interconnection queue. That vicious cycle continues, with the next round of wind and solar projects submitting even more interconnection applications to protect against this uncertainty. Cancelled projects lead to a vicious reinforcing cycle increasing the potential of further cancellations.

The high cost of interconnection is increasing the rate at which generators drop out of the interconnection queue, which exacerbates the uncertainty. Between January of 2016 and July of 2020, 245 clean energy projects in advanced stages of the MISO generator interconnection process chose to withdraw from the queue.[50] Interviews with the owners of these projects indicates that network upgrade costs were the primary reason for withdrawing.

Queue dropout rates are increasing. In 2019, approximately 3.5 of 5 GWs of renewable energy projects that had been a part of the MISO West 2017 study group dropped out of the interconnection queue due to high transmission upgrade costs. These projects, some of which already had power purchase agreements in place,[51] each faced transmission upgrade costs in the range of tens to hundreds of millions of dollars.[52] As of December of 2019, all but 250 MW of the 5,000 MWs had withdrawn from the queue. The remaining 250 MW was comprised of a 200 MW wind project and a 50 MW solar project; it is unlikely that the wind project will move forward as its engineering study showed the project would require transmission upgrades totaling $500 million.[53] This leaves the success rate at 1 percent for the MW in that queue study group.

Queue reform has attempted to reduce queue length and dropouts with larger financial deposits from interconnecting generators, yet queue backlogs continue to grow because queue reform has not addressed the fundamental problem of requiring interconnecting generators to pay for large network transmission elements that benefit the entire region.

d) Queue backlogs are large and growing

Interconnection queue timelines are increasing across the country due to the churn of re-studies and the high and unpredictable upgrade costs assignments, harming consumers' ability to access generation. Developers have said processing interconnection requests in PJM can take over two years, while processing in SPP can take nearly four years in some areas.[54] Currently, the MISO interconnection queue suggests processing times to be around three years, with the time it takes for a request to get through the process trending up over time.[55]

50 Sustainable FERC, *New Interactive Map Shows Clean Energy Projects Withdrawn from MISO Queue*, n.d.

51 Advanced Power Alliance, Clean Grid Alliance, and the American Wind Energy Association, *Comments to the SPP RSC and OMS Regarding Interregional Transmission Planning*, at 3, 2019.

52 Peder Mewis and Kelley Welf, *Clarion Call! Success has Brought Us to the Limits of the Current Transmission System*, November 12, 2019.

53 Jeffery Tomich, *Renewables 'Hit a Wall' in Saturated Upper Midwest Grid*, December 12, 2019.

54 Interviews with developers.

55 *See* MISO, *Interactive Queue*. We approximate the time it takes for an interconnection request to be processed by taking the difference between the "done date" of a request and the date the project entered the queue.

e) Interconnection challenges exist for offshore as well as onshore projects

Limitations of the current interconnection process hinder offshore wind development and state clean energy goals. Interconnection studies for offshore wind illustrate that most interconnection sites have a finite amount of capacity for new power injection before upgrade costs increase considerably, as the supply curve of available injection capacity among sites and at individual sites slopes steeply upward. According to upgrade costs estimated in PJM offshore wind interconnection studies and as shown in Appendix A, one can see that the first tranche of 605 MWs can be accommodated for an upgrade cost of around $275/kW at an interconnection site. The second tranche of 605 MW, however, incurs a marginal upgrade cost of over $1,100/kW, and the third tranche of 300 MWs incurs a marginal upgrade cost of over $1,300/kW. In this case, costs quadruple for projects later in the queue. The upgrades required for the later tranches involve rebuilding large segments of the transmission system. These investments benefit all interconnecting generators and consumers, who receive lower-cost and more reliable electricity from a stronger grid.

Appendix A also demonstrates that onshore transmission upgrade costs for interconnecting offshore generators tend to be very large. A review of 24 interconnection studies comprising 15,582 MWs of offshore wind capacity that have proposed to interconnect to PJM reveals $6.4 billion in total onshore grid upgrade costs for those projects, with an average of $413 per kW of offshore wind capacity.[56] Onshore grid upgrade costs for these offshore projects range from $10 per kW to $1,850 per kW.[57]

The status quo approach of relying on sequential interconnection studies with participant funding, without any pro-active regional planning, is leading to ballooning costs for offshore wind just like land-based renewables.

f) The problems occur mainly where participant funding is allowed—in RTOs and ISOs

FERC's interconnection policy as established in Order No. 2003 allowed participant funding inside RTOs and ISOs and not for transmission providers outside RTO/ISO areas. The problems described above are all in RTO/ISO areas. Where transmission upgrade costs are rolled into rates for all users, we do not find evidence of similar problems.

[56] Brandon W. Burke, Michael Goggin, and Rob Gramlich, *Offshore Wind Transmission White Paper*, at 14, October 2020.

[57] *Id.*

V. Incremental Solutions Can Help but Not Solve the Problem

a) Cluster study approaches have been a modest improvement

Some regions have implemented "cluster" interconnection studies, in which many interconnection requests are evaluated in the same study, as opposed to sequential project-by-project studies. The sequential processing approach is untenable for each new project that is the proverbial straw that breaks the camel's back and incurs a disproportionate share of upgrade costs. Clusters of similarly situated GI study requests, on the other hand, proved to be a preferred approach as transmission expansion is lumpy with large economies of scope and scale, so several developers in one area are able to pay a prorated share of the costs of required network upgrades. Additionally, grouping many interconnecting projects together instead of studying them individually allows for less queue reshuffling. Despite these advantages of a clustered approach, however, this does not solve the fundamental problem that all, or nearly all, costs are still assigned to interconnecting generators.

While clustering has helped in the past, it alone cannot solve the challenges associated with efficient and effective processing of generation interconnection queue requests. Current cluster sizes are extremely large in many cases, and planning for only one tranche of the future grid does not address the long-range needs, and certainly doesn't allow the capture of economies of scope and scale for large regional and interregional solutions to address aggregate network needs of resolving economic congestion and reliability concerns.

b) Eliminating participant funding would help

As part of FERC's Notice of Proposed Rulemaking (NOPR) for Order No. 2003, the Commission sought comment on whether or not they should retain their interconnection pricing policy.[58] At the time of the

[58] *Standardizing Generator Interconnection Agreements Procedures*, Notice of Proposed Rulemaking, Docket No. RM02-1, at 25, April 24, 2002.

NOPR, FERC's current policy required generators to pay 100 percent of the cost of "interconnection facilities" needed to establish the direct electrical connection between the generator and the existing transmission provider network. The costs of "network facilities," however – facilities at or beyond the point of interconnection to assist in accommodating the new generation facility (e.g. facilities needed for stability and short-circuit issues) – were borne initially by the generator and subsequently credited back to the generator through credits applied through transmission rates.[59]

In the final rule for Order No. 2003, FERC explained its reasoning for switching from such a "rolled-in" credit approach to one that is participant-funded.[60] One main reason included the credit approach's potential to provide price signals to direct developers to better locations from a network perspective. FERC argued at the time that a participant-funded pricing policy under which those who benefit from the project pay would help solve this problem.

FERC's decision to allow participant funding was based on the gas generation being added at the time. The Commission agreed with a number of commenters that objected to how the credit approach diminishes the incentive for interconnection customers to make efficient siting decisions while taking into account new network upgrade transmission costs, while effectively subsidizing interconnection customers who decide to sell output off-system.[61] The participant funding of network upgrades, FERC argued, would send more efficient price signals, more equally allocate costs, and potentially provide the framework necessary to allow incumbent transmission owners to overcome their reluctance to build much needed transmission.

The failure of the current system under the new resource mix, including excessive costs and risk, an inability to build needed transmission, and generators paying for large network upgrades that primarily benefit customers suggest that participant funding may no longer be a just and reasonable policy. Participant funding of network upgrades not only imposes costs on interconnection customers that are often exorbitant and rising, but is also not the solution to the inability to build large-scale transmission.

One policy solution would be to end participant funding for new generation. It is clear that major network upgrades resulting from generation interconnection requests provide economic and reliability benefits to loads and reduce congestion to improve grid efficiencies and operational flexibility, and therefore should not be direct assigned as a result of participant funding. The Commission can and should change this policy within the scope of interconnection policy.

c) Other incremental reforms to the interconnection process would help

The American Wind Energy Association (AWEA) petition for rulemaking in June of 2015 urged FERC to revise the pro forma LGIP and LGIA to alleviate "...unduly discriminatory and unreasonable barriers to generator market access."[62] AWEA's petition detailed a total of 14 recommendations and FERC later adopted 10 of the 14 under Order No. 845. The four recommendations FERC declined to adopt were regarding periodic restudies requirements, self-funding of network upgrades, publication of congestion and curtailment information, and the modeling of electric storage resources. In Order No. 845, FERC did not provide insight into what steps still needed to be taken to address these deficiencies in the current interconnection process.

59 *Standardizing Generator Interconnection Agreements Procedures*, Advance Notice of Proposed Rulemaking, Docket No. RM02-1, at 15, October 25, 2001. This was true unless the transmission provider elected to fund the network upgrades.

60 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 678, July 24, 2003.

61 *Id.* at P 695.

62 *Petition for Rulemaking of the American Wind Energy Association to Revise Generator Interconnection Rules and Procedures*, Docket No RM15-21-000, at 1, June 19, 2015.

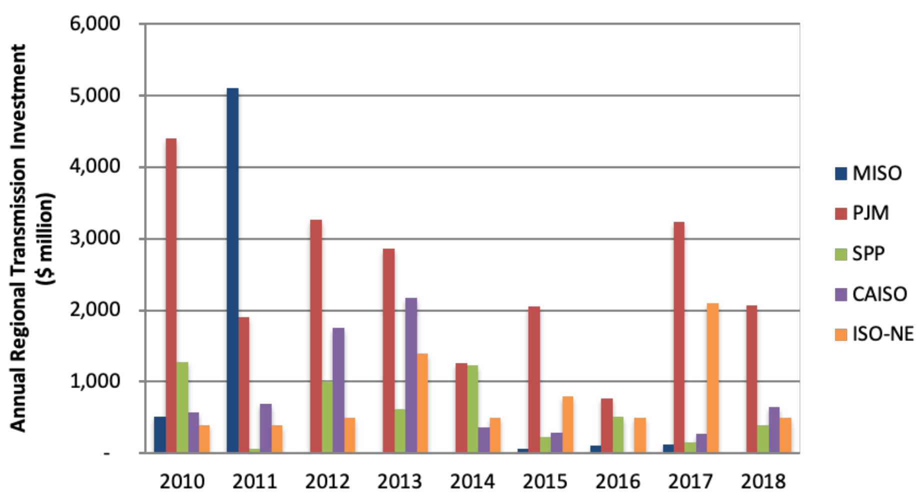
d) Interconnection process changes would still leave a shortage of efficient regional transmission

Even with the incremental changes above, there would be a continued lack of efficient regional transmission without more fundamental reforms. Integrated and comprehensive planning efforts to address to effectively integrate expected generation while also meeting economic and reliability needs have not happened since major initiatives such as Competitive Renewable Energy Zones (CREZ) in ERCOT, MVPs in MISO, and Priority Projects in SPP. Once those lines were fully subscribed, upgrade costs and queue backlogs quickly returned to unworkable levels.

While current transmission investment numbers are relatively high by historical standards, the majority of recent transmission investments have been small local projects, as demonstrated by Brattle: "[A]bout one-half of the approximately $70 billion of aggregate transmission investments by FERC-jurisdictional transmission owners in ISO/RTO regions are approved outside the regional planning processes or with limited ISO/RTO stakeholder engagement."[63]

Without sufficient regional and interregional transmission capacity to facilitate the integration of location-constrained resources onto the grid, the cost of constructing the network upgrades necessary to interconnect new wind and solar resources falls on generators as part of the interconnection process. As demonstrated in most RTO regional transmission planning statistics and reports, regionally planned transmission investment has decreased substantially since 2010. Specifically, between 2010 and 2018, total regionally planned transmission investment in RTOs decreased by 50 percent as shown in Figure 4.[64]

Figure 4: Annual Regionally Planned Transmission Investment in RTOs/ISOs ($ million)



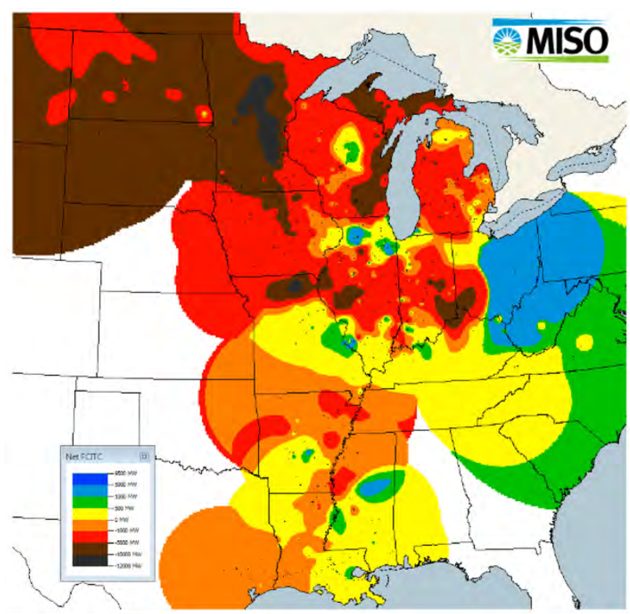
[63] Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 4, April 2019 ("Significant investments have been made, but relatively little has been built to meet the broader regional and interregional economic and public policy needs envisioned when FERC issued Order No. 1000. Instead, most of these transmission investments addressed reliability and local needs.")

[64] Note: all RTOs/ISOs provide regional transmission investment information. Grid Strategies assembled data using the following sources to assemble figure 4: Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, *Section 206 Complaint and Request for Fast Track Processin*g, at 31-32, January 21, 2020; PJM, *Project Statistics*, at 6, January 10, 2019; Lanny Nickell, *Transmission Investment in SPP*, at 5, July 15, 2019; CAISO, *ISO Board Approved Transmission Plans*, years 2012-2021 available under "Transmission planning and studies" section of webpage; CAISO, *2011-2012 Transmission Plan*, March 14, 2012; CAISO, *Briefing on 2010 Transmission Plan*, 2010; and ISO New-England, *Transmission*, accessed October 2020.

There have been successful examples of region-wide coordination in planning and cost allocation achieving efficient levels of transmission investment. Transmission expansion efforts with pro-active multi-value planning and broad cost allocation, like the CREZ in ERCOT, MVPs in MISO, and Priority Projects in SPP, for example, have led to the large buildout of backbone transmission. These transmission expansion plans pro-actively incorporated wind and solar development assumptions, and also designed transmission upgrades that would maximize other economic and reliability benefits. Most importantly, these policies were successful because the costs of transmission were broadly allocated across the region, consistent with the benefits of the transmission being broadly spread across the region, instead of unworkably attempting to recover the costs through the generator interconnection process. However, these successful pro-active transmission planning efforts were not sustained. Subsequent renewable development requests in these areas have been burdened with unreasonable costs for interconnections, and queue backlogs have grown as a result.

The decline of regional plans is inconsistent with the evolving resource mix. Because the best locations for wind and solar resources are significantly different from those of retiring coal and other thermal resources, the current grid based on approved plans cannot be expected to support future needs. Transmission has a long infrastructure life, so the infrastructure built today should be designed with the next 50 years in mind. While almost all generation resources are location-constrained to some extent, wind and solar tend to be more constrained to areas with high-quality resources and therefore require more transmission.[65] Yet less transmission is being planned as wind and solar resources make up an increasing portion of the resource mix, which can severely constrain the amount of transmission transfer capacity out of renewable-heavy areas. Figure 5[66] below, for example, shows the majority of western MISO (highlighted in blue) had an estimated 5 GW or more deficit of transfer capacity to the rest of the region in 2016. This means that at least that amount of transmission capacity must be constructed across MISO and into the PJM region before any new generation can be added.

Figure 5: MISO West Transfer Capacity Deficit

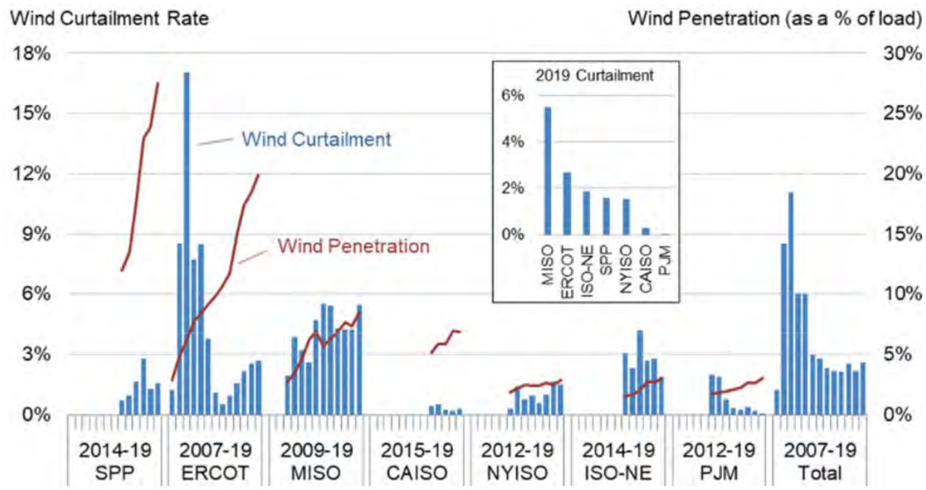


[65] *See* American Wind Energy Association, *Grid Vision: The Electric Highway to a 21st Century Economy*, at 31, May 2019; Scott Madden, *Informing the Transmission Discussion*, at 29, January 2020; FERC, *Report on Barriers and Opportunities for High Voltage Transmission*, at 12-14, June 2020.

[66] *See* MISO transfer capacity contour map, available at https://cdn.misoenergy.org/GI-Contour_Map108143.pdf, July, 11, 2018.

Efficient regional transmission capacity for location-constrained renewables can help lower renewable curtailment levels. Average wind curtailment levels for the RTOs hovered around 2.6 percent in 2019, up from 2.2 percent in 2018, with the highest levels in MISO and ERCOT at 5.5 percent and 2.7 percent, respectively.[67] Regions with high wind curtailment levels, specifically in western MISO and northwestern ERCOT, benefitted from the construction of new, large regional transmission. As shown in Figure 6[68] below, wind curtailment in MISO decreased from 2015 through 2018 shortly after the completion of a number of MVPs in western MISO between 2013-2017.[69] Similarly, wind curtailment in ERCOT has declined dramatically since 2011 after the completion of CREZ transmission projects from 2010 through 2013 allowed more than 18,500 MWs of wind capacity to be transported throughout the state.[70]

Figure 6: Wind Curtailment and Penetration Rates by ISO



Sources: ERCOT, MISO, CAISO, NYISO, PJM, ISO-NE, SPP

67 Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 49, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

68 Id.

69 MISO, *Regionally Cost Allocated Project Reporting Analysis*, October 2020.

70 ERCOT, *Report on Existing and Potential Electric System Constraints and Needs*, at iii, December 2018. U.S. Energy Information Administration, *Fewer Wind Curtailments and Negative Power Prices Seen in Texas After Major Grid Expansion*, June 24, 2014

VI. The Real Solution Must Be Regional and Inter-regional Planning Reforms

Transmission expansion needs to be driven by a multi-value plan to address overall system needs, including economics, reliability, and generator interconnection. Some regions have demonstrated success in integrated transmission plans to accommodate projected futures that resulted in very cost-effective transmission expansion. CREZ in ERCOT, MVPs in MISO and Priority Projects in SPP are case studies where loads, generators and stakeholders benefited from holistic planning efforts. SPP and MISO have found the benefits of that transmission expansion exceeded the cost by 2 to 3 times.[71]

The changing resource mix and electrification of the energy sector will have a profound impact on the future grid, yet in many cases those factors are not being included in regional and interregional planning efforts. Most recent regional planning studies have not included reasonable projections regarding the changing resource mix and expected retirements. State policies should also be accounted for in regional transmission planning process.

Network upgrades benefit everyone, and all costs ultimately flow to customers, so cost allocation needs to reflect that reality. Consumers benefit from minimizing costs and maximizing the benefits of transmission expansion. Customers are also harmed by the inefficient and unworkable status quo that attempts to force upgrade costs on interconnecting generators. This policy leads to a sub-optimal level of transmission investment, driving billions of dollars annually in unnecessary congestion and reliability costs, while the cost of energy offered to customers by generators is higher than necessary due to lengthy queue delays and risk and an inability to build generation in low-cost resource areas.

Transmission policy can and should include Grid-Enhancing Technologies (GETs), not just new infrastructure. As FERC has recognized, a set of GETs are now widely commercialized and deployable to address a number of transmission challenges speedily and at low cost. GETs can be incorporated into interconnection policy, transmission planning, and FERC incentives policy. As with infrastructure,

[71] *See* SPP, *The Value of Transmission*, at 5, January 26, 2016; MISO, *MTEP17 MVP Triennial Review*, at 4, September 2017.

addressing only interconnection policy will not be sufficient for GETs.

a) Generator lead lines should be incorporated into regional plan

In many cases, a lack of transmission capacity, queue backlogs, and excessive participant funding upgrade costs have forced renewable developers to build and own generator lead lines that are dozens of miles long. For example, wind projects such as Horse Hollow in ERCOT and Flat Ridge in SPP had in-service dates and commitments for deliveries that could not wait for approved, regionally funded Extra High Voltage (EHV) network upgrades. As a result, developers of these projects built long, high capacity EHV generator leads to integrate their projects into existing transmission facilities in advance of planned regionally funded upgrades. In the case of Horse Hollow, the developer constructed a private 345 kV line extending from West ERCOT to South ERCOT – a distance spanning ten Texas counties.[72] Often long generator leads reduce congestion and curtailments and become network elements benefitting everyone.

b) Affected system studies need to be part of improved interregional planning processes

Affected system studies occur when a generator interconnection in one RTO triggers a need for transmission upgrades in more than one RTO. These studies increase upgrade costs for generators. The fact that the transmission need is large enough to cross into another RTO clearly indicates that the transmission expansion benefits others, and therefore should be planned and paid for in a regional, and ideally inter-regional, process.

Planning is tough enough within an RTO, and the planning and cost allocation obstacles for building transmission between RTOs are currently insurmountable. Part of the problem is there is significant divergence among RTO planning processes, with different models, assumptions, benefit-cost thresholds, and timing. As a result, no large-scale transmission upgrades have been able to pass what is called the "triple hurdle," which requires an inter-regional transmission project to pass a benefit-cost ratio test in each RTO and for the entire region. The free rider problem is an even greater challenge for inter-regional cost allocation than it is within RTOs. However, the large need for inter-regional transmission will not be met without solving that problem, likely by broadly allocating the cost of inter-regional lines across those regions.

The voluntary nature of RTOs has resulted in footprints that create seams issues that stymie collaborative planning. Expansion of RTO footprints helps to mitigate seams issues to a large extent and needs to be strongly encouraged. The lack of transmission capabilities between zones of an RTO creates challenges that have plagued effective expansion planning. Transmission capabilities are critical to an efficient and effective bulk power system and electricity market, as transmission is the critical link to enabling and defining markets.

c) Regional planning studies and generation interconnection studies need better alignment

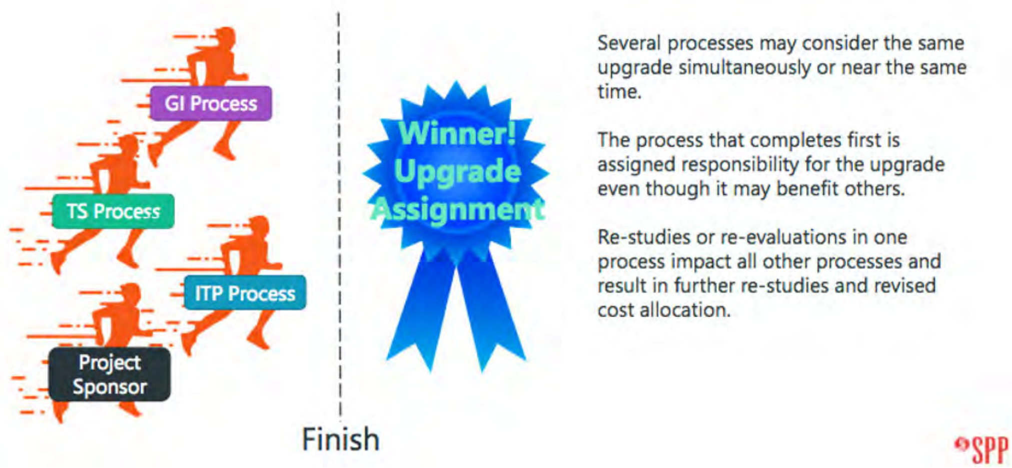
Planning entities often employ siloed study processes that consider reliability, economic, and public policy

[72] Hillard Energy, *Horse Hollow Generation Tie*, Comfort, Texas, n.d.

transmission projects separately rather than considering all benefits at once under a holistic planning approach. The main factor driving siloed planning processes is that different cost allocation methods for each category of transmission project results in a race that no one wants to win, as it will result in them bearing the cost for the transmission upgrades. Said another way, each group of stakeholders attempts to free ride on other groups of stakeholders by failing to plan transmission that they would have to pay for, in the hope another group of stakeholders will plan and pay for it. Unfortunately, the typical result is that nobody builds the transmission, and all customers suffer from increased congested and reduced reliability.

A great case study that demonstrates this failure in action involves SPP's filing of an unexecuted GIA between SPP - the transmission provider, Oklahoma Gas & Electric (OG&E) Company - the transmission owner, and Frontier Windpower II - the interconnection customer.[73] After Frontier's GIA identified shared network upgrades including a new transmission line with a $62 million price tag, of which Frontier had been allocated 22.5 percent of the total cost, Frontier then asked SPP to file the GIA as an unexecuted agreement. When SPP later revised Frontier's GIA to remove all costs associated with the new transmission line, the back-and-forth continued as OG&E submitted a filing in protest of SPP's decision as they believed that because Frontier is imposing costs on the SPP system, they should bear their share of the cost so others, including OG&E, do not have to pay more.[74] SPP's Strategic & Creative Re-Engineering of Integrated Planning Team (SCRIPT) has identified this problem, as shown in Figure 7.[75]

Figure 7: Process Interaction



SPP is working on a solution, which builds on the successes achieved through pro-active transmission planning and broad cost allocation identified a decade ago with the ERCOT CREZ, MISO MVP, and SPP Priority Project lines. The new SCRIPT effort at SPP appears to be a positive step forward and may serve as a model for other RTOs. The scope of the SCRIPT at SPP is noteworthy in several respects. "The SCRIPT is tasked with developing policy recommendations that result in:

- Appropriate consolidation, modification, or elimination of SPP's transmission planning and study processes, in order to:
    - Develop more optimal solutions that meet a broader set of customer needs

73 *Protest of Oklahoma Gas and Electric Company*, Docket No. ER19-2747-002, March 16, 2020.

74 Id. at 7-8.

75 *See* the minutes and meeting materials for SCRIPT's meeting held on October 9th, 2020 (attachment D at slide 49).

» Synergize analysis so that beneficiaries and cost-causers can be identified in a holistic, uniform fashion

» Improve planning efficiency, effectiveness and timeliness

» Reduce the number of model sets needed

» Reduce reliance on customer-requested, queue-driven studies

- Improved responsiveness, efficiency and cost certainty of studies needed to provide customer-requested service
- Reduced dependence on queue-driven studies, with consideration given to development of proactive processes that identify and make transparent underutilized transmission capacity
- Utilization of processes and information needed to ensure decisions being made about future investment in transmission infrastructure are made with a high degree of confidence and quality
- Optimization of the existing and planned transmission network to most cost effectively meet future needs while providing maximum value to the region
- Facilitation of generation transfers in a way that will provide future net benefits to the SPP region
- Improved cost sharing among users of the transmission system that appropriately recognizes causers and beneficiaries of transmission investment decisions"

d) Both incremental and broader reforms would still be fuel-neutral

If FERC were to change its policies based in part on the evolving resource mix, that could still be a fuel neutral policy. FERC has always tried to be neutral, with no discrimination or preference to any particular resource, and that can remain true. Transmission policy necessarily takes into account the physical location of resources. For example, in 2007, FERC issued policies on interconnection and transmission service for "location-constrained" resources that differed from the Order 2003 approach in CAISO.[76] It was not a preference or any value judgment on the renewable resources, just the recognition that there was a large resource area that could be tapped with a higher voltage transmission lines than any one generator or group of generators could be assigned, leading to more just and reasonable rates for consumers. Transmission planning reforms could follow this general approach.

[76] See *California Independent System Operator Corporation*, Order Granting Petition for Declaratory Order, 119 FERC ¶ 61,061, April 2007; and Bracewell LLP, *FERC Tailors Transmission to Connect Renewables*, May 1, 2007. See also Pedro J. Pizarro, *Transmission Planning and Development: Examples and Lessons*, at 17, February 25, 2010; CAISO, *Memorandum re: Decision on Tehachapi Project*, at 6, fn. 3 January 18, 2007 (explaining how generators would pay a pro-rata share to the extent the Tehachapi improvements are characterized as bulk transfer gen-tie lines, with customers in SCE's service territory paying the costs of the network upgrade portions of the project).

VII. Conclusion: Transmission Planning as Well as Interconnection Policy Reforms Are Needed

The current system of participant funding and network planning through the interconnection process is increasingly unworkable and inefficient. While participant funding and serial interconnection studies created workable signals for siting interconnecting gas plants, they create inefficiencies for interconnecting location-constrained renewable resources. Needed transmission remains unbuilt because the vast majority of new proposed projects drop out of the queue, lengthy queue backlogs create massive uncertainty and risk for generation developers, and congestion and reliability problems from a constrained grid impose billions of dollars per year in unnecessary costs on customers. All generation and transmission costs ultimately flow to electricity consumers, so there is no benefit from policies that seek to shift transmission costs from RTO customers exclusively to generators. The risk from the uncertainty of the interconnection process significantly increases the cost of capital for generation developers, which increases the cost of energy for customers. The question for policymakers is how to create a workable and efficient system of planning and paying for transmission that minimizes customer costs.

Interconnection policy and transmission planning policy both need to fit the resource mix going forward. This paper provides evidence of how the interconnection policy is broken now, given the current and expected future resource mix. It proposes some recommendations within the scope of interconnection policy such as ending the policy of assigning all the costs of network upgrades just to generators. However, major progress requires improved transmission expansion policies in order to build out grid capacity to accommodate the future resource mix. Reform to regional transmission planning raises a number of issues that are beyond the scope of this paper. A companion paper from ACEG will address the need for planning reform, consider various policy options, and recommend a number of specific policy changes. It is clear that regional and inter-regional planning must be pro-active, consider future generation additions and retirements, consider multiple benefits, and spread costs to all beneficiaries. That is the only real solution to the broken interconnection processes around the country.

Appendix[77]

Queue Position	MW	Request Date	COD	Interconnection Point	State	County	Trans. Owner	Feasibility Study	System Impact Study	Facilities Study	$ upgrade cost	$/kW upgrade cost
Z1-035	18	7/5/13	9/30/17	Lake Road 11.5 kV	OH	Unknown	ATSI	Complete	Complete	Not required	$2,468,558	$137
AB1-056	255.1	8/31/15	10/31/21	Indian River 230kV I	DE	Sussex	DPL	Complete	Complete	Complete	$2,556,112	$10
AE1-020	816	5/22/18	6/1/23	Oyster Creek 230 kV	NJ	Ocean	JCPL	Complete	Complete	In Progress	$111,316,644	$136
AE1-104	432	9/6/18	6/1/23	BL England 138 kV	NJ	Cape May	AEC	Complete	Complete	In Progress	$65,050,000	$151
AE1-117	152	9/14/18	6/1/22	Bethany 138 kV	DE	Sussex	DPL	Complete	Complete	In Progress	$9,698,945	$64
AE1-238	816	9/28/18	6/1/24	Oceanview Wind 230 kV	NJ	Monmouth	JCPL	Complete	Complete	In Progress	$13,498,200	$17
AE2-020	604.8	12/14/18	12/1/24	Cardiff 230 kV I	NJ	Atlantic	AEC	Complete	Complete	In Progress	$167,856,800	$278
AE2-021	604.8	12/14/18	12/1/25	Cardiff 230 kV II	NJ	Atlantic	AEC	Complete	Complete	In Progress	$668,716,213	$1,106
AE2-022	300	12/14/18	12/1/24	Cardiff 230 kV III	NJ	Atlantic	AEC	Complete	Complete	In Progress	$399,595,257	$1,332
AE2-024	882	12/14/18	12/1/25	Larrabee 230 kV I	NJ	Ocean	JCPL	Complete	Complete	In Progress	$179,417,245	$203
AE2-025	445.2	12/14/18	12/1/26	Larrabee 230 kV II	NJ	Ocean	JCPL	Complete	Complete	In Progress	$171,405,063	$385
AE2-122	800.1	2/28/19	12/31/25	Birdneck-Landstown 230 kV	VA	City of Virginia Beach	Dominion	Complete	Complete	In Progress	$304,108,327	$380
AE2-123	800.1	2/28/19	12/31/27	Birdneck-Landstown 230 kV	VA	City of Virginia Beach	Dominion	Complete	Complete	In Progress	$243,757,023	$305
AE2-124	800.1	2/28/19	12/31/29	Landstown 230 kV	VA	City of Virginia Beach	Dominion	Complete	Complete	In Progress	$215,266,218	$269
AE2-222	300	3/22/19	6/1/23	Higbee 69 kV	NJ	Atlantic	AEC	Complete	Complete	In Progress	$285,840,760	$953
AE2-251	1200	3/26/19	6/1/24	Cardiff 230 kV	NJ	Monmouth	AEC	Complete	Complete	In Progress	$923,771,404	$770
AE2-257	120	3/27/19	6/1/22	Cedar Neck 69 kV	DE	Sussex	DPL	Complete	Complete	In Progress	$105,062,883	$876
AF1-101	800	9/6/19	11/23/22	Oyster Creek 230 kV III	NJ	Atlantic	JCPL	Complete	Complete		$572,211,265	$715
AF1-123	880	9/17/19	12/31/25	Fentress 500 kV	VA	City of Chesapeake	Dominion	Complete	Complete		$76,200,000	$87
AF1-124	880	9/17/19	12/31/26	Fentress 500 kV	VA	City of Chesapeake	Dominion	Complete	Complete		$156,865,407	$178
AF1-125	880	9/17/19	12/31/24	Fentress 500 kV	VA	City of Chesapeake	Dominion	Complete	Complete		$149,505,894	$170
AF1-222	1326	9/27/19	12/30/25	Oceanview Wind 2 230 kV	NJ	Monmouth	JCPL	Complete	Complete		$131,556,667	$99
AF2-193	440	3/23/20	10/31/26	Indian River 230 kV I	DE	Sussex	DPL	Complete			$534,708,000	$1,215
AF2-194	880	3/23/20	10/31/26	Indian River 230 kV II	DE	Sussex	DPL	Complete			$664,582,000	$755
AF2-196	150	3/23/20	6/1/22	Cedar Neck 69 kV II	DE	Sussex	DPL	Complete			$277,459,000	$1,850
											$6,432,473,885	$413/kW average

77 See PJM, New Services Queue. To gather the data found in Appendix A, we filtered the queue for offshore wind projects. Upgrade cost information was taken from the most recent interconnection study available for each request (e.g. feasibility study, system impact study, or facilities study).

Americans for a
Clean Energy Grid

EXHIBIT 3

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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March 2021

CONCENTRIC ENERGY ADVISORS

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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

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.

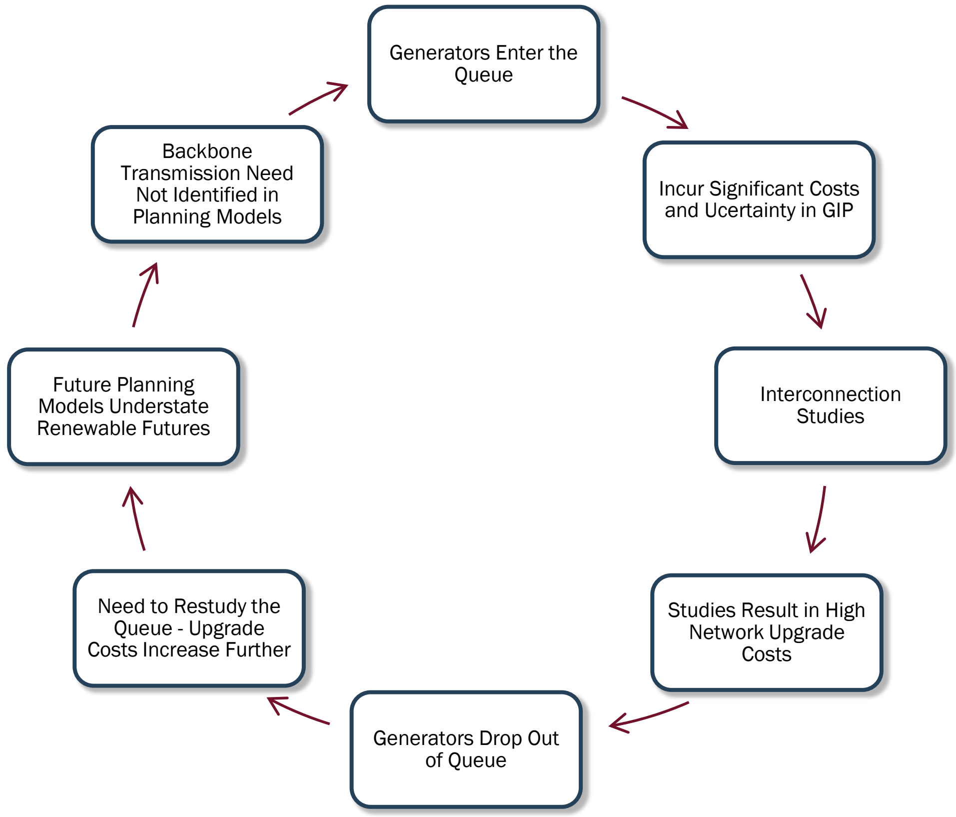
agreements. This disconnect is one contributing factor to the persistent and overly conservative forecasts of renewable resource expansion in transmission planning models and the inability of planning models to identify the necessary transmission expansion for future renewable generation.

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.

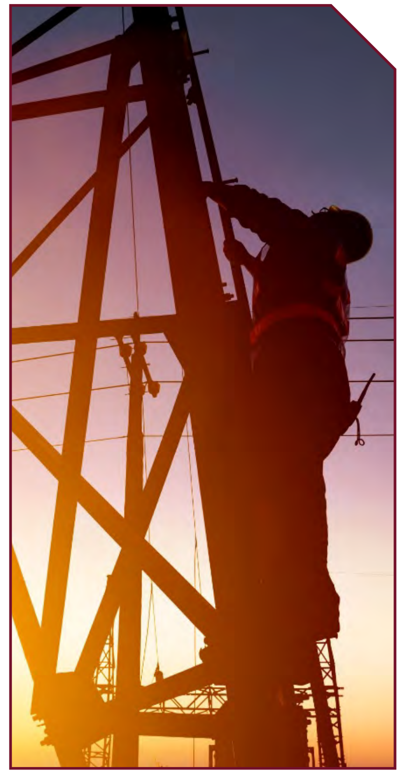
Concentric conducted 20 confidential interviews with individuals representing key market participants, of which 4 were investor-owned utilities active in transmission development and renewable energy development; 2 were consultants specializing in electric transmission; 1 was an infrastructure developer (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

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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.

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]

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.

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*

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

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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 or
	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.

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.

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*

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

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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]

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

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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]

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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]

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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.

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]

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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

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/.

EXHIBIT 4

TRANSMISSION MAKES THE POWER SYSTEM RESILIENT TO EXTREME WEATHER

Grid Strategies LLC

ACORE
AMERICAN COUNCIL ON RENEWABLE ENERGY

PREPARED FOR ACORE, WITH SUPPORT FROM THE MACRO GRID INITIATIVE

AUTHOR
MICHAEL GOGGIN
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JULY 2021

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This February, millions of Americans experienced prolonged power outages when electricity demand exceeded supply as record cold gripped much of the Central U.S. Power outages are always life-threatening for those who rely on electric medical devices, but they can be dangerous for anyone during a period of extreme cold or heat. Tragically, it appears the February power outages contributed to hundreds of deaths in Texas alone.[1] Electricity is also increasingly the lifeblood of America's economy, and is essential for powering first responders and national security workers. The Congressional Research Service estimates that weather-related power outages cost Americans $25-70 billion annually.[2]

Investigations are underway to determine what caused February's outages. Regardless of which energy sources failed, strengthening transmission is an essential part of the solution for preventing future outages. Extreme weather events tend to be most severe in relatively small areas, so stronger transmission ties to neighboring regions can be a lifeline to keep homes warm and people safe. Transmission ties cancel out local fluctuations in the weather that affect electricity demand. This is primarily due to heating/cooling needs and supply, including changes in wind and solar output as well as failures of conventional power plants due to extreme weather.

Many severe weather events migrate from region to region, allowing one region to import during its time of need and then export to other regions once the storm moves on. Grid operators have confirmed that connecting large geographic areas via transmission saves billions of dollars per year by reducing the need for power plant capacity by reducing variability in electricity supply and demand.[3] A strongly integrated grid network also provides valuable resilience, so if some power lines or power plants are taken offline by any type of disaster, there are alternative sources of power available.

1 Peter Aldhous, Stephanie M. Lee, and Zahra Hirji, "The Texas Winter Storm and Power Outages Killed Hundreds More People Than the State Says," (May 26, 2021), available at: https://www.buzzfeednews.com/article/peteraldhous/texas-winter-storm-power-outage-death-toll.

2 Executive Office of the President, *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages*, (August 2013), available at: https://www.energy.gov/sites/default/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf.

3 For example, see PJM, "PJM Value Proposition," (2019) available at: https://www.pjm.com/about-pjm/-/media/about-pjm/pjm-value-proposition.ashx, MISO, "Value Proposition," (n.d.), available at: https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-value-proposition/.

EXECUTIVE SUMMARY

Severe weather events are becoming more common and more extreme, with severe events challenging nearly every part of the U.S. power grid in the last decade alone.[4] This analysis reviews five recent severe weather events to determine the value additional transmission would have provided.

February 2021 Winter Storm Uri — Each additional 1 GigaWatt (GW) of transmission ties between the Texas power grid (ERCOT) and the Southeastern U.S. **could have saved nearly $1 billion, while keeping the heat on for hundreds of thousands of Texans**. With stronger transmission ties, other parts of the Central U.S. also could have avoided power outages while saving consumers hundreds of millions of dollars. In particular, consumers in the Great Plains, served by the Southwest Power Pool (SPP), and those in the Gulf Coast states, served by the southern part of the Midcontinent Independent System Operator (MISO), **each could have saved in excess of $100 million** with an additional 1 GW of transmission ties to power systems to the east.

Texas heat wave in August 2019 — An extended heat wave in Texas led to high power prices across 12 days in August 2019. An additional 1 GW transmission tie to the Southeast could have **saved Texas consumers nearly $75 million**. As summer heat waves become more frequent and severe, the value of transmission for delivering needed electricity supplies from regions that are less affected will grow.

The "Bomb Cyclone" cold snap across the Northeast in December 2017-January 2018 — New England, New York, and the Mid-Atlantic region suffered cold weather for nearly three weeks, causing natural gas price spikes and nearly exhausting fuel oil supplies in New England. **Each of these regions could have saved $30-40 million** for each GW of stronger transmission ties among themselves or to other regions. These regions routinely switched between importing and exporting as the most severe cold migrated among the regions over the course of the three-week event, demonstrating that transmission benefits all users across broad geographic areas. In addition, one GW of stronger transmission ties between eastern and western PJM, the grid operator for much of the region between the Mid-Atlantic and Chicago, would have provided over $40 million in net benefits during this event.

4 See, e.g. NOAA National Centers for Environmental Information, "Billion-Dollar Weather and Climate Disasters: Overview," (2021), available at: https://www.ncdc.noaa.gov/billions/.

The January 2014 "polar vortex" event in the Northeast — New England, New York, and the Mid-Atlantic region suffered several days of extreme cold in early January 2014. The grid operator for the Mid-Atlantic region, PJM, resorted to voltage reductions to avoid the need for rolling outages. **Greater transmission ties within and among these regions could have saved consumers tens of millions of dollars and prevented reliability concerns.** Like the 2017/2018 Bomb Cyclone event, regions switched between importing and exporting as the most extreme cold migrated from region to region.

The "polar vortex" event in the Midwest in 2019 — While an additional 1 GW of transmission between MISO and PJM would have only saved a few million dollars during this short-lived cold snap, this event was notable for illustrating how transmission expansion benefits both interconnected regions. As the extreme cold moved eastward from MISO to PJM, so did the high power prices, and transmission flows switched from westward to eastward.

These results for these five events are summarized in the table below. For reference, long-distance transmission costs around $700 million per GW of transfer capacity, based on the average cost for the 18 above-ground shovel-ready projects identified in a recent report, though costs vary considerably based on the length of the line and other factors.[5] In the case of the February 2021 Texas outages, the value of power delivered to Texas could have fully covered the cost of new transmission to the Southeast, while for other lines and severe weather events the value could have defrayed a significant share of the cost of building transmission.

TABLE 1. *Value of 1 GW of additional transmission by region for each event*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
WINTER STORM URI, FEBRUARY 2021	
ERCOT – TVA	$993
SPP South – PJM	$129
SPP South – MISO IL	$122
SPP South – TVA	$120
SPP S – MISO S (Entergy Texas)	$110
MISO S-N (Entergy Texas - IL)	$85
MISO S (Entergy Texas) – TVA	$82
TEXAS HEAT WAVE, AUGUST 2019	
ERCOT – TVA	$75
NORTHEAST BOMB CYCLONE, DECEMBER 2017 – JANUARY 2018	
Eastern PJM (VA) – Western PJM (Northern IL)	$43
NYISO – PJM	$41
PJM – MISO	$38
NYISO – ISONE	$29
NORTHEAST POLAR VORTEX EVENT, JANUARY 2014	
PJM – MISO	$17
NYISO – PJM	$9
NYISO – MISO	$21
MIDWEST POLAR VORTEX EVENT, JANUARY 2019	
MISO – PJM	$2

For each event, the savings across the multiple potential new lines are not always additive, with the total savings tending to be somewhat lower than the sum of all lines' savings. This is because building the first line into a region will alleviate some of the congestion, reducing the value of additional lines into that region.

5 Michael Goggin, Rob Gramlich, and Michael Skelly, *Transmission Projects Ready to Go: Plugging Into America's Untapped Renewable Resources*, (April 2021), available at: https://cleanenergygrid.org/wp-content/uploads/2019/04/Transmission-Projects-Ready-to-Go-Final.pdf.

Across these events, transmission congestion tends to recur at certain notable points on the grid, confirming the need for expanded transmission in those areas. Expanding transmission between ERCOT and the Southeast, from SPP and MISO to power systems to the east like PJM and the Southeast, between western and eastern PJM, and among eastern PJM, New York, and New England appears to be particularly valuable for protecting against the impact of severe weather.

These events demonstrate that all generation sources are vulnerable to severe weather, making increased transmission to broaden the pool of available resources one of the best options for increasing resilience. ERCOT[6] and SPP[7] data for the February 2021 event show that coal, gas, diesel, wind, solar, nuclear, and hydropower plants were all taken offline by the record cold and ice; however, gas generators accounted for the majority of outages, with the cold causing generator equipment failures as well as fuel interruptions due to overwhelmed pipeline capacity and frozen gas wells.

Despite the large savings identified above, transmission's value for making the grid more resilient against severe weather and other unexpected threats is not typically accounted for in transmission planning and cost allocation analyses. Grid operator transmission planning processes typically assume normal electricity supply and demand patterns, and in most cases do not account for the value of transmission for increasing resilience. Transmission's hedging or insurance value from protecting consumers against the economic and reliability impacts of these rare events is also not typically accounted for.

As a result, pro-transmission policies need to be enacted to account for the resilience benefits of transmission. Just as President Eisenhower created the interstate highway system to protect national security and facilitate interregional trade, there is a clear national interest in ensuring that the backbone of the 21st century economy — the power grid — is strong and secure.

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6 ERCOT, "Hourly Resource Outage Capacity," (2021), available at: http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13103&reportTitle=Hourly%20Resource%20Outage%20Capacity&showHTMLView=&mimicKey.

7 SPP, "Capacity of Generation on Outage," (2021), available at: https://marketplace.spp.org/pages/capacity-of-generation-on-outage#%2F2021%2F02.

Federal legislation and action by the Federal Energy Regulatory Commission (FERC) can enable the needed investment. A tax credit for building high-voltage transmission lines is now under consideration in Congress. FERC can require greater regional and interregional coordination in how transmission is planned and paid for, and could require minimum levels of interregional transmission to ensure grid reliability. Congress could also pass legislation directing FERC to make those changes.

A stronger grid will be valuable every day, not just during extreme weather events. Many of the new transmission lines that would have been highly valuable during these severe weather events are the same ones needed to deliver the Midwest's low-cost wind resources to electricity demand centers to the east. Power can flow in both directions on transmission, so both ends of the line benefit. Most of the time these lines will export wind generation from the Midwest, but during an emergency power can flow back into the Midwest.

Many recent studies show that interregional transmission lines like those discussed in this paper become increasingly essential as wind and solar penetrations increase in different parts of the country. Just as these lines aggregate diverse sources of electricity supply and demand to balance out localized disruptions during extreme weather, they provide a similar value by canceling out local fluctuations in wind or solar output.[8]

There have also been other extreme temperature and severe weather events in other regions over the last decade in which stronger transmission ties would have been similarly valuable.[9] However, those events occurred in regions without centralized power markets or in regions that were not adjacent to those with centralized power markets, making it more difficult to quantify the value of transmission due to the lack of transparent market price information. It is likely that these regions could have seen benefits from transmission expansion that are comparable to those quantified in this report.[10] The following section discusses in more detail the value additional transmission could have provided during the five recent severe weather events.

8 For example, *see* Patrick Brown and Audun Botterud, "The Value of Interregional Coordination and Transmission in Decarbonizing the US Electricity System," (January 20, 2021), Joule, Volume 5, Issue 1, at 115-134, available at: https://www.sciencedirect.com/science/article/abs/pii/S2542435120305572?dgcid=author; Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, (December 15, 2020), available at: https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf; Aaron Bloom et al., *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study*, (October 2020), available at: https://www.nrel.gov/docs/fy21osti/76850.pdf; NREL, Renewable Electricity Futures Study," (2012), available at: https://www.nrel.gov/docs/fy13osti/52409-ES.pdf; Christopher Clack, Michael Goggin, Aditya Choukulkar, Brianna Cote, and Sarah McKee, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.*, (October 2020), available at: https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf.

9 For example, many parts of the Western U.S. have experienced record heat or cold, or natural gas supply interruptions like the Aliso Canyon leak and British Columbia pipeline explosion, that resulted in power outages or extreme price spikes. See, e.g. outages and price spikes in the Southwest following extreme cold and gas supply interruptions, FERC and NERC Staff, *Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations*, (August 2011), available at: https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf. Similarly, many utilities in the Southeast have been challenged by unusual cold snaps or extreme heat and drought. See, e.g. FERC and NERC Staff, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, (July 2019), available at: https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf.

10 For example, in August 2020 California experienced power outages and high prices when a high level of generator outages coincided with record-breaking heat across many parts of the Western U.S. While this event was highly unusual in that the extreme heat affected much of the West at the same time, additional transmission capacity to other regions still could have helped alleviate the outages and price spikes. The California grid operator has calculated that congestion on transmission ties with other regions, mostly the Pacific Northwest, added around $45 million in consumer costs, while transmission congestion within California imposed an additional $37 million in costs.

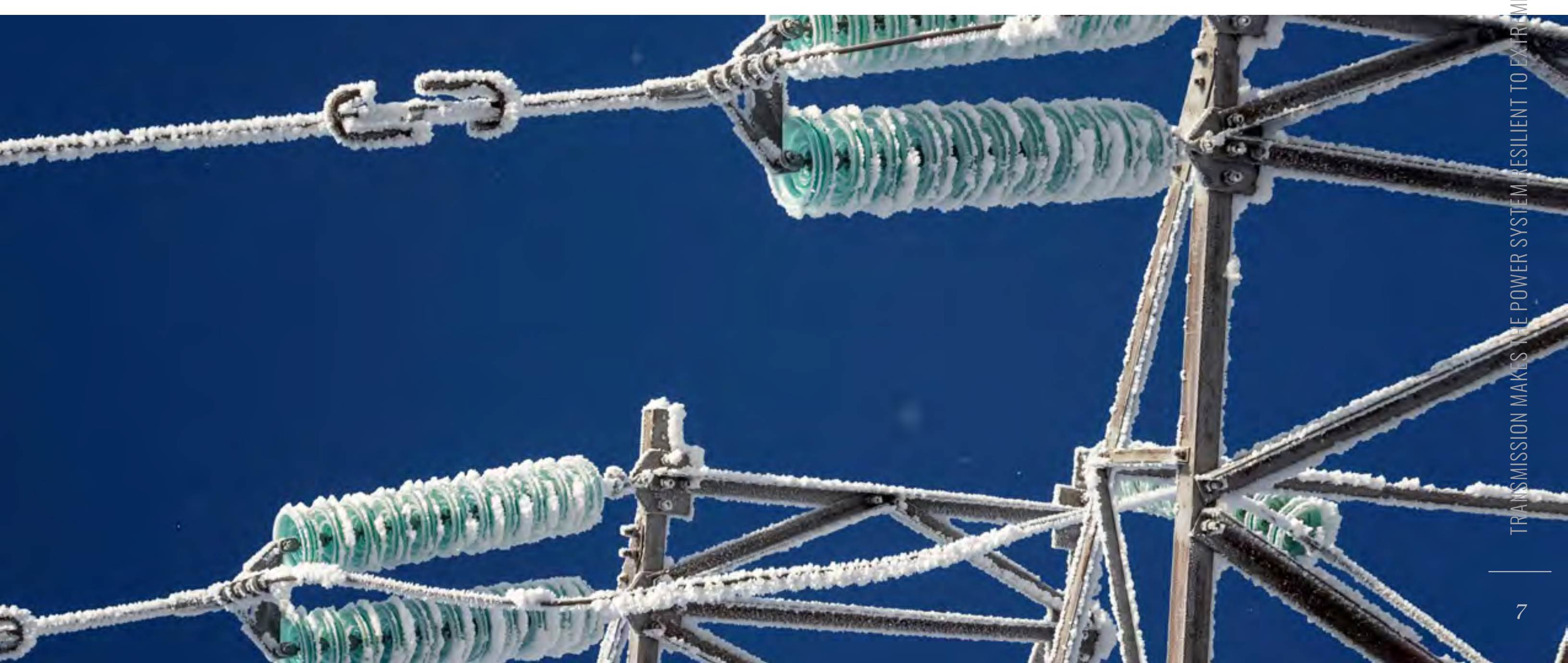
RESULTS: VALUE OF TRANSMISSION DURING RECENT SEVERE WEATHER EVENTS

These events demonstrate that all generation sources are vulnerable to severe weather, making increased transmission to broaden the pool of available resources one of the best options for increasing resilience. Almost all severe weather events are at their most extreme in a relatively narrow geographic area, so transmission allows surplus electricity supplies to be delivered from neighboring regions that are not experiencing extreme electricity demand or loss of generating supply.

Winter Storm Uri in February 2021

The value of transmission for resilience can be seen in the drastically different outcomes of MISO and SPP relative to ERCOT during the February 2021 cold snap event. SPP and MISO were able to weather the storm with much less severe power outages thanks to stronger transmission ties to neighboring regions that allowed them to import more than 15 times as much power as ERCOT.

While SPP and MISO also experienced extreme cold, they were able to avoid major power shortfalls by importing electricity from regions experiencing milder temperatures, mostly to the east. As shown in the bottom half of the Department of Energy chart below, at maximum MISO was importing nearly 9,000 megawatts (MW) from PJM, several thousand MW from the Tennessee Valley Authority (TVA), and around an additional 1,000 MW each from Southern Company, Louisville Gas and Electric, and Canada.[11] Total MISO imports were consistently over 13,000 MW during the most challenging period from midday February 15 to midday February 16.



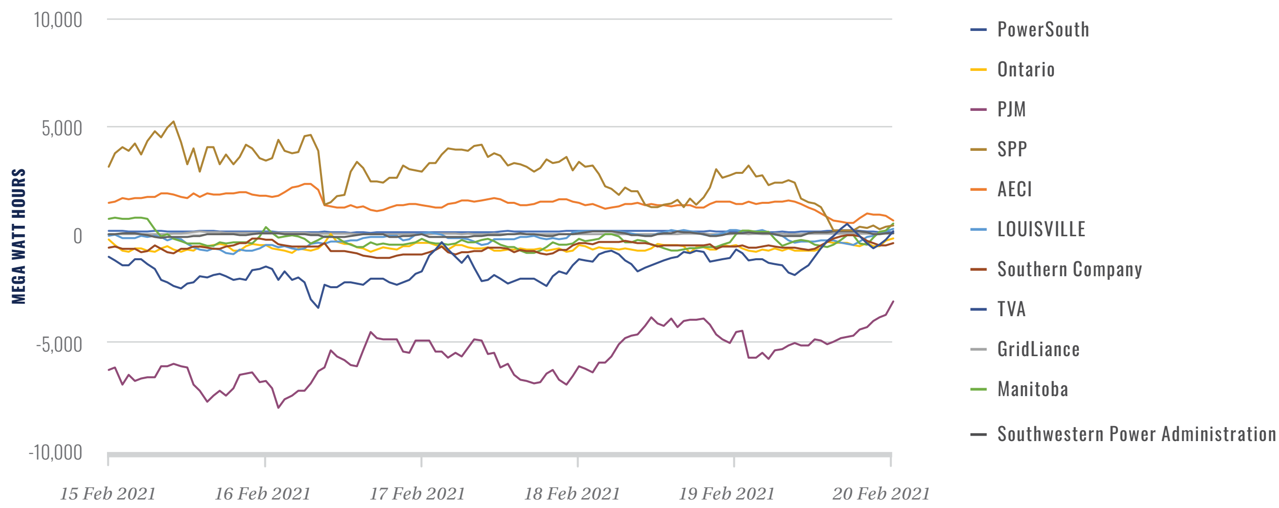


FIGURE 1. *Midcontinent Independent System Operator, Inc. (MISO) electricity interchange with neighboring balancing authorities 2/15/2021-2/19/2021, Eastern Time*

In turn, MISO was exporting to power systems to its west, delivering over 5,000 MW to SPP and nearly 2,500 MW to the Associated Electric Cooperative Incorporated, as shown in the top part of the chart. Thus around half the power MISO was importing was effectively flowing through MISO to reach power systems farther to the west.

In contrast to the 13,000 MW MISO was importing during the peak of last month's event, ERCOT was only able to import about 800 MW of power throughout the event, as shown below. ERCOT was initially able to import nearly 400 MW from Mexico, though those imports were cut early on February 15 when Mexico also experienced generator outages due to a loss of gas supply. Imports from SPP were also briefly cut at various points as SPP experienced its own shortages, particularly on February 16.

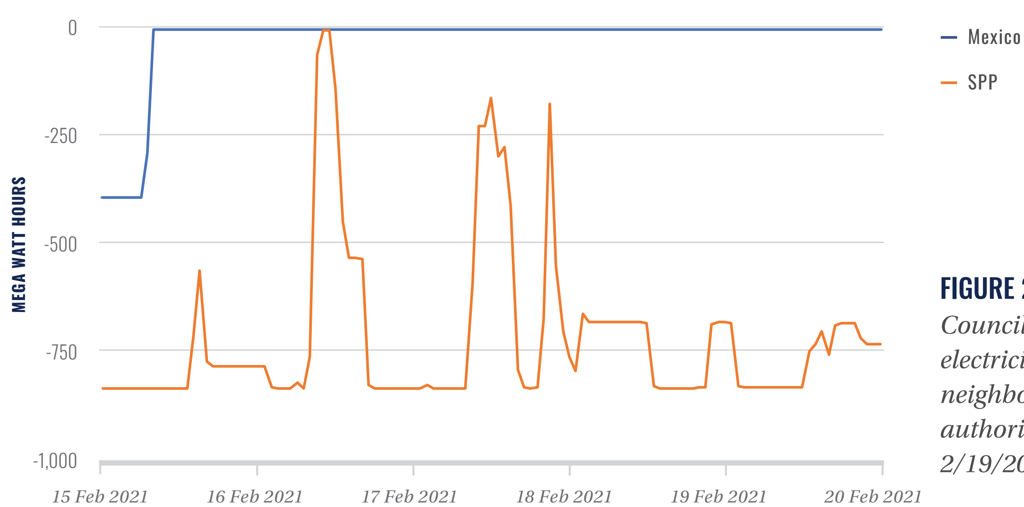


FIGURE 2. *Electric Reliability Council of Texas, Inc. (ERCOT) electricity interchange with neighboring balancing authorities 2/15/2021-2/19/2021, Eastern Time*

MISO and SPP also could have benefited from stronger transmission ties to neighboring regions, as well as stronger ties between northern and southern MISO. Power prices in SPP and southern MISO spiked during the event, reaching or exceeding the $1,000/MWh price cap in those markets as prices for natural gas spiked.[12] The need for more transmission capacity was also reflected in the strong west-to-east price gradient across MISO and PJM shown below, with prices in the hundreds of dollars per MWh in MISO versus around $50/MWh in eastern PJM on the morning of February 15.

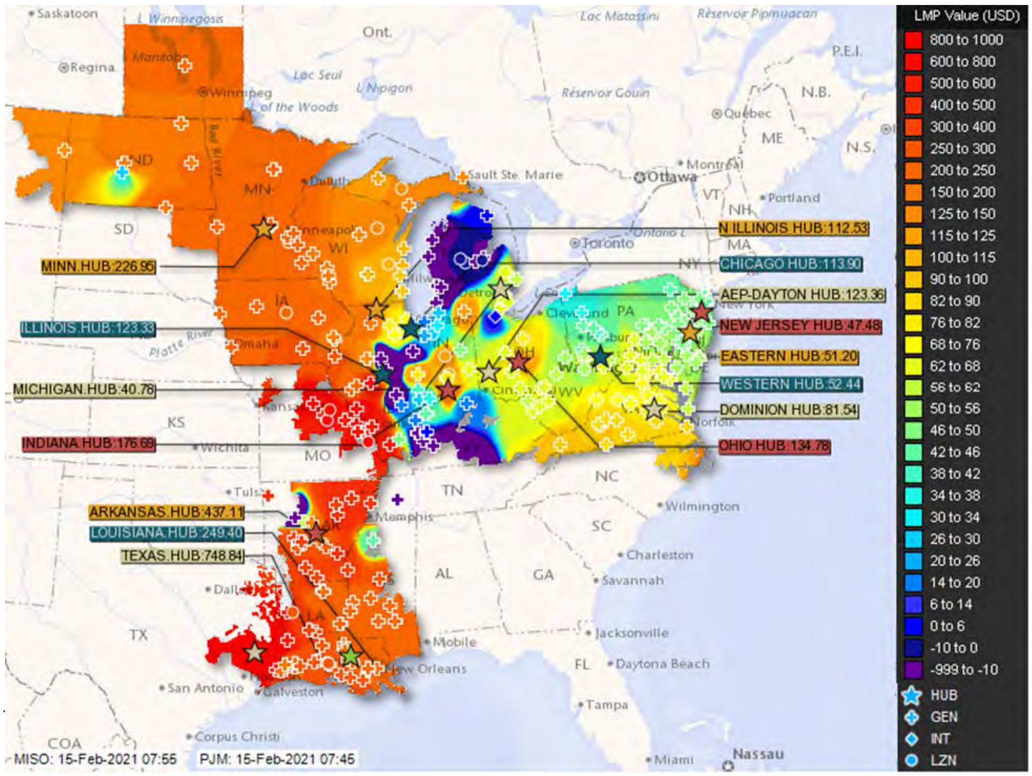


FIGURE 3. *Snapshot of power prices on the morning of February 15, 2021*

Transmission congestion costs at the seams between PJM, MISO, and SPP routinely approached $2,000/MWh throughout the event, reflecting the need for more transmission.[14] In many cases those costs flow to consumers who are forced to buy more expensive power because there was insufficient transmission capacity to deliver lower-cost imports. As is often the case, a large amount of transmission congestion at the MISO-PJM seam in Illinois and Indiana prevented more power from reaching SPP and MISO. Grid-enhancing technologies that allow more power to be transferred across transmission lines likely would have reduced the outages and price spikes in MISO and SPP.[15] Long-standing operational issues at the seams between the markets may have also contributed to the congestion and caused the localized pockets of very low

12 SPP, "Order 831 Verification Frequently Asked Questions," (April 1, 2021), available at: https://www.spp.org/documents/64402/spp%20mmu%20order%20831%20verifcation%20faq%20v4.pdf.

13 Screenshot taken February 15, 2021, from Joint and Common Market Contour Map, available at https://www.miso-pjm.com/markets/contour-map

14 MISO, "SRW Hourly Market-to-Market Settlements," (2021), available at: https://docs.misoenergy.org/marketreports/M2M_Settlement_srw_2021.csv.

15 T. Bruce Tsuchida, Stephanie Ross, and Adam Bigelow, *Unlocking the Queue With Grid-Enhancing Technologies,"* (February 1, 2021), available at: https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

prices along the seam shown in the map above.[16]

Throughout the event, transmission constraints within MISO were also limiting the transfer of power from areas with more abundant power to areas with higher prices. The quantity and price impact of binding transmission constraints within MISO were at least an order of magnitude higher than a typical winter day.[17] Price differences between northern MISO and southern MISO were also extreme throughout the event, routinely hitting $500/MWh.[18]

The following chart shows our analysis of the extreme price differences among these neighboring grid areas during Winter Storm Uri, illustrating the value of expanding transmission ties among these regions. Power prices in PJM, TVA, and MISO Illinois remained relatively low throughout the event, while prices in ERCOT were consistently high. Interestingly, power prices in SPP South and MISO South were minimally or even negatively correlated throughout much of the event, indicating that increased transmission capacity could have significantly benefited both regions. About two-thirds of our calculated $110 million in savings per GW of increased transmission between those regions would have accrued to SPP ($72 million), while one-third would have accrued to MISO ($38 million). As discussed below, it is common for transmission to benefit both ends of the transmission line over the course of many severe weather events, as the area of the most severe weather often migrates over time.

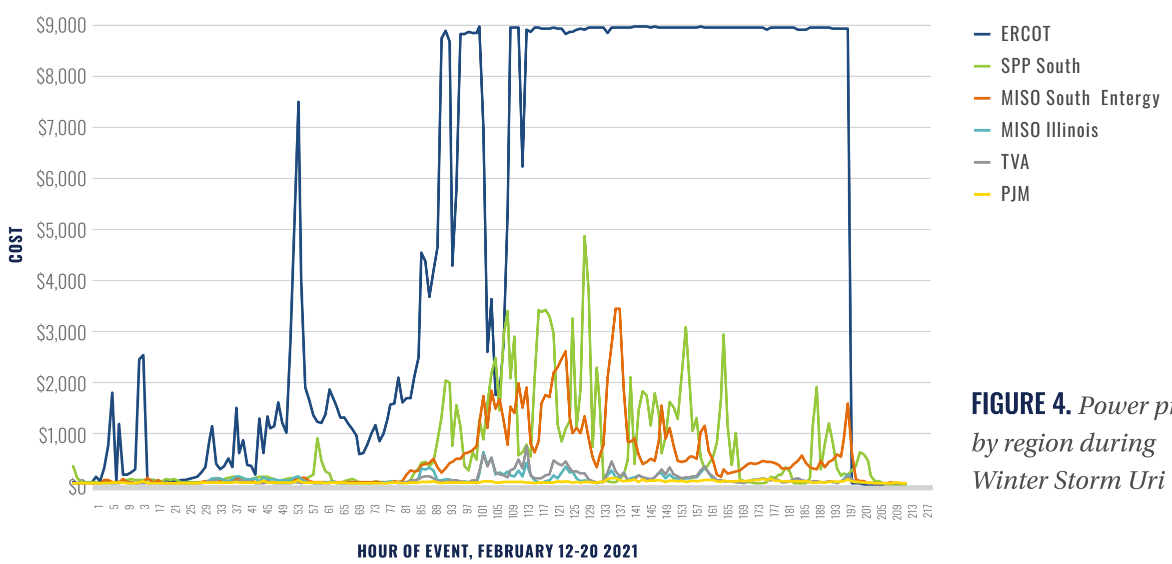


FIGURE 4. *Power prices by region during Winter Storm Uri*

16 David Patton and Mike Wander, "Identification of Seams Issues for OMS/SPP RSC," (March 19, 2021), available at: https://www.spp.org/documents/59674/oms_rsc_seamsissuesmemo.pdf.

17 MISO, "Real-Time Binding Constraints," (2021), available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AReal-Time%2FMarketReportName%3AReal-Time%20Binding%20Constraints%20(xls)&t=10&p=0&s=MarketReportPublished&sd=desc.

18 MISO, "Real-Time Binding Sub-Regional Power Balance Constraints," (2021), available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AReal-Time%2FMarketReportName%3AReal-Time%20Binding%20Sub-Regional%20Power%20Balance%20Constraints%20(csv)&t=10&p=0&s=MarketReportPublished&sd=desc.

Additional Transmission Could Have Alleviated Price Spikes and Kept the Heat on During Uri

More transmission capacity from ERCOT, MISO, and SPP to power systems to the east, such as PJM and TVA, and between northern MISO and southern MISO, and could have greatly alleviated these price spikes. Using the methodology described in the Appendix, our analysis finds large consumer savings for each potential 1 GW addition of transmission capacity, with savings approaching $1 billion for 1 GW of additional ties between ERCOT and the Southeast, and over $100 million for most of the other lines.

TABLE 2. *Savings per additional GW of transmission, February 12-20, 2021*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
ERCOT – TVA	$993
SPP South – PJM	$129
SPP South – MISO IL	$122
SPP South – TVA	$120
SPP S – MISO S (Entergy Texas)	$110
MISO S-N (Entergy Texas - IL)	$85
MISO S (Entergy Texas) – TVA	$82

Because ERCOT, MISO, and SPP were all forced to resort to rolling power outages during this event, the value of transmission is not only measured in dollars. A stronger transmission network could have kept the heat and power on for millions of homes and businesses, avoiding devastating loss of life and property. ERCOT says that one MW powers 200 homes during times of peak usage, so each additional 1 GW of transmission could have kept the lights on for around 200,000 Texas homes. The total electricity shortfall in ERCOT was around 10-20 GW during February's event, so multiple high-capacity transmission lines could have greatly alleviated the pain inflicted by the outages. Because many of the gas generator failures in ERCOT were due to interdependencies between the electric system and the gas supply system, like the use of electricity to power pipeline compressors and wellhead equipment, it is possible that several high-capacity transmission lines could have entirely prevented the power outages. Transmission also helps to protect national security. During Winter Storm Uri, several military bases were forced to close due to a loss of power, or the loss of water service when water utilities lost power.[19]

Transmission projects have been proposed for many of the interregional paths identified in the table above. Pattern Energy has proposed the 2 GW Southern Cross transmission line between ERCOT and Southeastern power systems like TVA. FERC and Texas regulators have determined that this line would not interfere with ERCOT's independence from FERC regulation, so those

19 Rose L. Thayer, "Winter Weather Causes More Than a Dozen Military Bases to Close," (February 16, 2021), available at: https://www.stripes.com/news/us/winter-weather-causes-more-than-a-dozen-military-bases-to-close-1.662417.

concerns should not prevent the construction of this or other transmission between ERCOT and FERC-regulated power markets.[20] Our analysis showing nearly $1 billion in savings per GW of transmission indicates that, had Southern Cross been in service during Winter Storm Uri, it could have provided nearly $2 billion in value by delivering 2 GW from the Southeast to ERCOT for the duration of the event. This value greatly exceeds the $1.4 billion estimate cost for the transmission project in this single event, without even considering the additional billions of dollars in benefits it would provide over the many decades of the project's life.[21]

Other proposed lines would have benefited SPP and MISO. Grain Belt Express, originally developed by Clean Line and now owned by Invenergy, is proposed to run between SPP South and PJM. The Clean Line Plains and Eastern line, the Oklahoma portion of which is now owned by NextEra Energy, would have connected SPP South with the Southeast. MISO's transmission planning processes routinely examine stronger transmission ties between northern and southern MISO, and studies have shown significant value for transmission between SPP, MISO, and PJM. Unfortunately none of those lines have been built, primarily due to disagreements over who should pay for the transmission.

Those two lines could have provided hundreds of millions of dollars in benefits during Winter Storm Uri alone. While that is not enough to cover the full cost of those transmission lines, it adds to the savings they provide during normal operations. Across the half century or longer life of a typical transmission line, it is almost certain that the line will provide critical supplies of power during at least one severe weather event — particularly with the frequency and magnitude of severe weather increasing. Accounting for resilience benefits in transmission planning and cost allocation would significantly increase the calculated benefit-to-cost ratio of transmission, enabling more transmission projects to move forward.

The experience of MISO and SPP during February's Winter Storm Uri likely would have been even worse had they not made large internal investments in transmission over the last decade.

During a recent MISO Board meeting, MISO President Clair Moeller stated that the Multi-Value Project transmission lines that his organization has built over the last decade, at a cost of around $6.5 billion,[22] provided around $18 billion in benefits across three days of Winter Storm Uri.[23]

20 Pattern Energy, "Pattern's Southern Cross Transmission Project Receives Key FERC Approvals," (December 19, 2011), available at: https://www.prnewswire.com/news-releases/patterns-southern-cross-transmission-project-receives-key-ferc-approvals-135852828.html.

21 *Southern Cross Transmission LLC*, Direct Testimony of David Parquet on Behalf of Southern Cross Transmission LLC, (2017), Attachment A, 2017-UA-79, at 7, available at: https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=385777.

22 MISO, "Regionally Cost Allocated Project Reporting Analysis: 2011 MVP Portfolio Analysis Report," (January 2021), available at: https://cdn.misoenergy.org/MVP%20Dashboard%20Q4%202020117055.pdf.

23 This calculation is different from that presented in this paper, as it is based on the cost of the more extensive power outages that would have happened without recent transmission investments, at an assumed cost of around $20,000/MWh of unserved energy. In contrast, our analysis evaluates reductions in power prices with potential additional transmission.

Other severe weather events have also challenged the South Central region, though none was as severe as Winter Storm Uri. On February 2, 2011, ERCOT experienced rolling outages when cold weather similarly caused power plant outages and natural gas supply shortages. Millions of Texans experienced rolling outages that morning, and power prices hit the then-price cap of $3,000/MWh.[24] An extended heat wave in summer 2011 also challenged the power grid in ERCOT, causing high prices but no widespread outages. During another cold snap on January 6, 2014, ERCOT prices spiked to $5,000/MWh, and prices have gone even higher during other extreme temperature and severe weather events.

During other severe weather events, ERCOT could have delivered needed power to neighboring regions, reversing the flows that were seen in February 2021. MISO South, SPP South, and parts of the Southeast experienced extreme cold on January 17, 2018, causing over 14,000 MW of unexpected generation outages and bringing utilities to the brink of implementing rolling outages.[25] Stronger east-west transmission ties to ERCOT and power systems to the east, and transmission to northern SPP and MISO, could have alleviated the resulting price spikes and prevented reliability concerns.

August 2019 ERCOT heat wave

An extended heat wave in Texas led to high power prices across 12 days in August 2019. An additional 1 GW transmission tie to the Southeast could have saved Texas consumers nearly $75 million, per our calculations using the methodology described in the Appendix. As shown below, power prices in TVA and MISO South remained consistently low across the 12 days, while prices in ERCOT spiked most afternoons. Additional transmission ties to those regions, or to SPP or the Western Interconnect, could have prevented those price spikes.

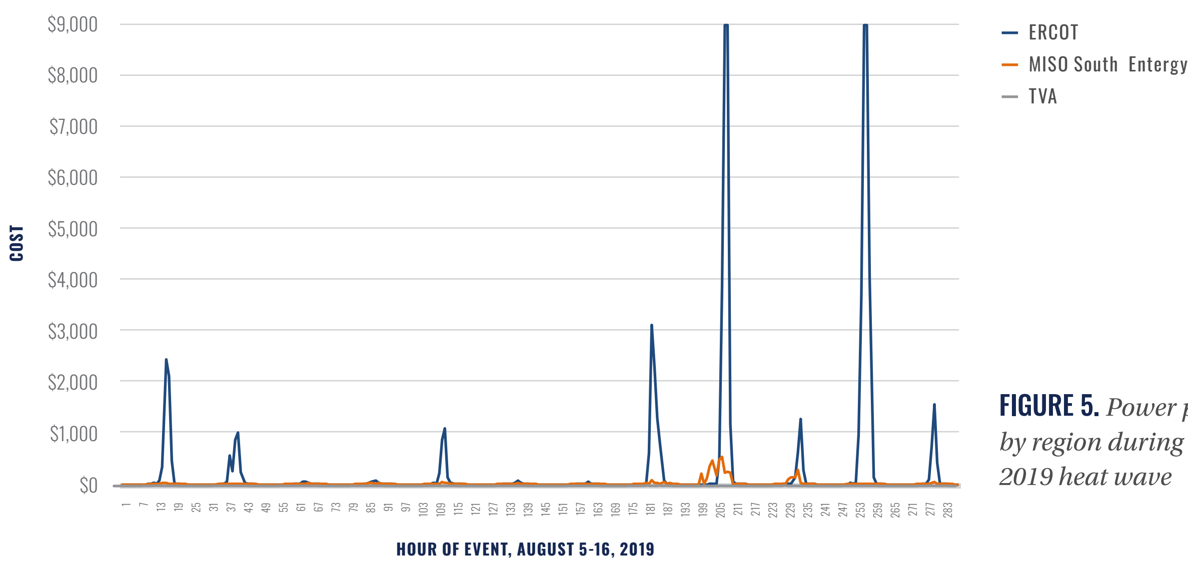


FIGURE 5. *Power prices by region during August 2019 heat wave*

24 Potomac Economics, LTD., *Investigation of the ERCOT Energy Emergency Alert Level 3 on February 2, 2011,* (April 21, 2011), available at: http://www.ercot.com/content/meetings/tac/keydocs/2011/0505/09._IMM_Report_Events_020211.pdf.

25 FERC and NERC Staff, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, (July 2019), available at: https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf.

The “Bomb Cyclone” cold snap across the Northeast in December 2017-January 2018

New England (ISO-NE), New York (NYISO), and the Mid-Atlantic region (PJM) suffered cold weather for nearly three weeks, causing natural gas price spikes and nearly exhausting fuel oil supplies in New England. As summarized in the table below, each of these regions could have saved around $30-40 million for each GW of stronger transmission ties among themselves or to other regions. More specifically, PJM could have saved around $38 million from each GW of greater imports from MISO to its west. One GW of stronger transmission ties between eastern and western PJM also could have provided over $40 million in net benefits during this event.[26]

TABLE 3. *Savings per additional GW of transmission, December 26, 2017 – January 19, 2018*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
Eastern PJM (VA) – Western PJM (Northern IL)	$43
NYISO – PJM	$41
PJM – MISO	$38
NYISO – ISO-NE	$29

PJM, New York, and New England routinely switched between importing and exporting as the most severe cold migrated among the regions over the course of the three-week event, demonstrating that transmission benefits all users across broad geographic areas. The chart below shows how eastern PJM, New York, and New England experienced price spikes at different times during the event. New York prices were highly volatile given the relatively small size of its market and lack of transmission ties to neighboring regions. ComEd power prices, in western PJM, were consistently low throughout the event, even as power prices spiked in Virginia and other parts of eastern PJM. Largely as a result, PJM reported $900 million in internal PJM transmission congestion costs in the first half of 2018, up from $285 million in the first half of 2017.

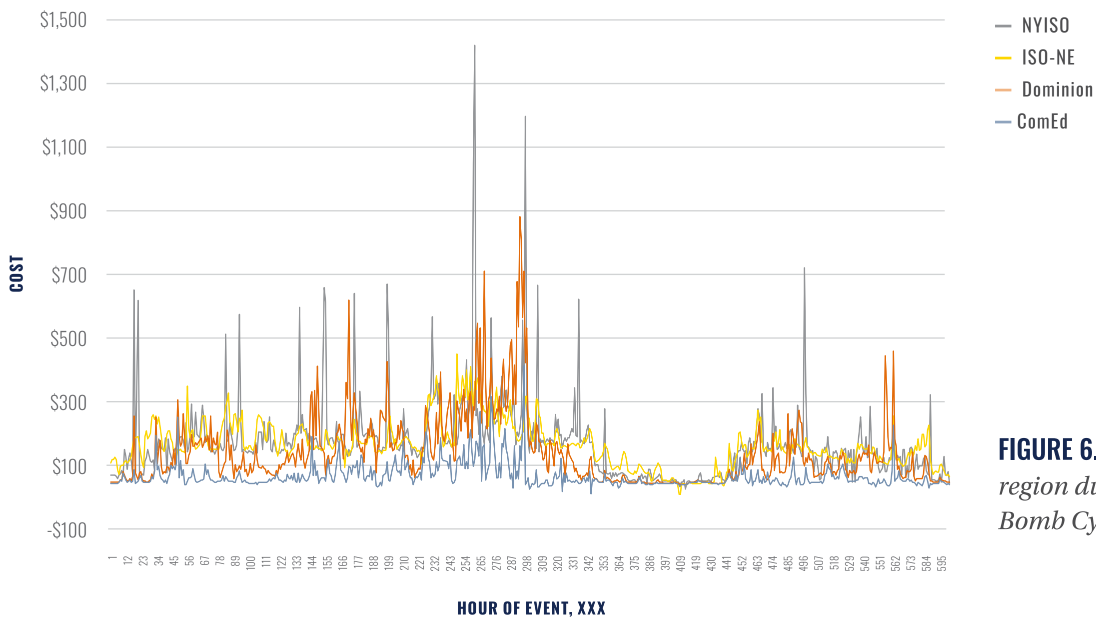


FIGURE 6. *Power prices by region during 2017-2018 Bomb Cyclone*

The January 2014 "polar vortex" event in the Northeast

The Central U.S., Northeast, and Mid-Atlantic regions suffered several days of extreme cold in early January 2014. PJM was forced to resort to system-wide voltage reductions to avoid the need for rolling outages. Greater transmission ties within and among these regions could have saved consumers tens of millions of dollars and prevented reliability concerns.

TABLE 4. *Savings per additional GW of transmission, January 5-10, 2014*

Receiving region – delivering region	Savings per GW of additional transmission capacity (millions of $)
PJM – MISO	$17
NYISO – PJM	$9
NYISO – MISO	$21

As shown below, prices were generally lower in MISO throughout the event, as the most extreme cold was located to the east in PJM and New York. Delivering power from MISO to PJM, or even to NYISO, would have greatly reduced consumer costs, as shown in the table above.

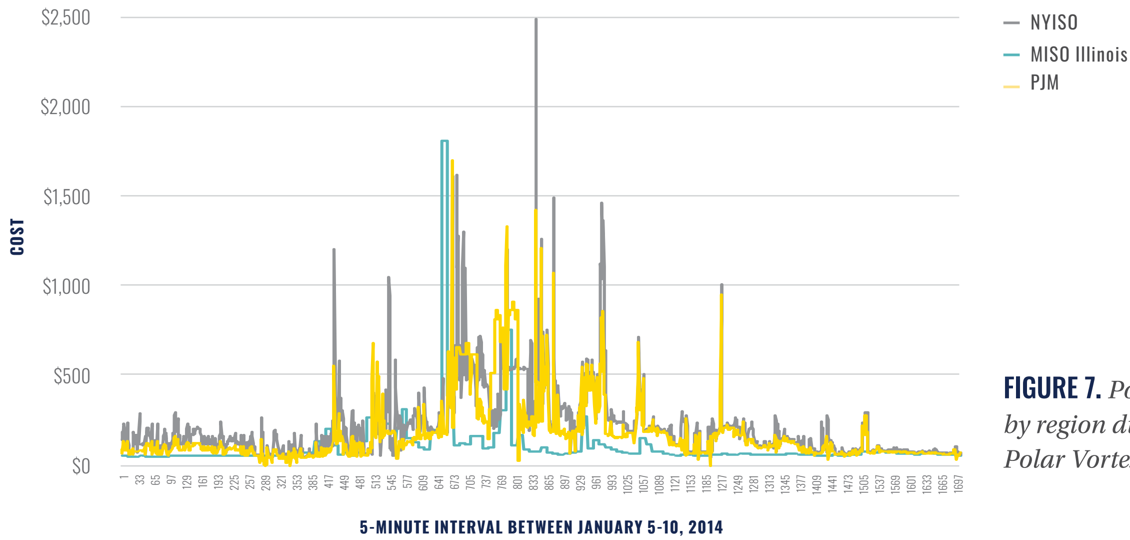


FIGURE 7. *Power prices by region during 2014 Polar Vortex*

Like in the 2017/2018 Bomb Cyclone event, regions switched between importing and exporting as the most extreme cold migrated from region to region. This trend was most apparent the morning of January 7, the day when most regions experienced the most extreme cold. As shown in the following chart that zooms in on that morning, each region moving west to east lagged the other by an hour or two in experiencing the highest prices.

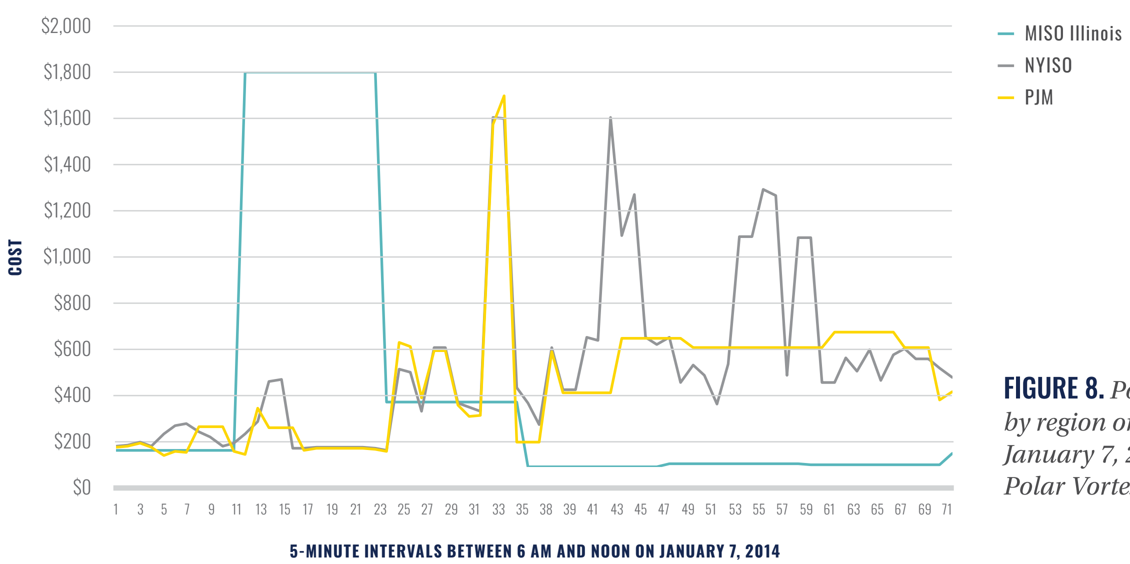


FIGURE 8. *Power prices by region on morning of January 7, 2014, during Polar Vortex*

The “polar vortex” event in the Midwest in 2019

While an additional 1 GW of transmission between MISO and PJM would have saved around $2.4 million dollars during this short-lived cold snap, this event was more notable for illustrating how transmission expansion benefits both interconnected regions. As the extreme cold moved eastward from MISO to PJM on January 30-February 1, 2019, so did the high power prices, and transmission flows switched from westward to eastward.

Early on January 30, MISO’s wind output dropped off as temperatures fell below the low temperature limit for wind turbines, forcing them to shut down. Fortunately, wind output in PJM was nearly twice as high as average. This higher wind output helped PJM export in excess of 5,000 MW of power westward to the Midwest grid operator (MISO) during its time of peak demand, a reversal of the typical eastward flow of power. This shows the value of wind’s geographic diversity paired with a well-connected grid, creating a more resilient overall system. Transmission also allowed MISO and PJM to take advantage of the diversity in their electricity demand patterns, in addition to the diversity in their wind output. PJM electricity demand was relatively low on the morning of January 30 when MISO experienced its peak demand, while MISO demand was lower by that evening when PJM experienced its peak demand for the day.

This lagged shift in need can be seen in the chart of power prices below. Because of the lack of correlation between PJM and MISO in both electricity supply and demand, the $2.4 million in benefits from an additional GW of transmission are evenly split between the regions.

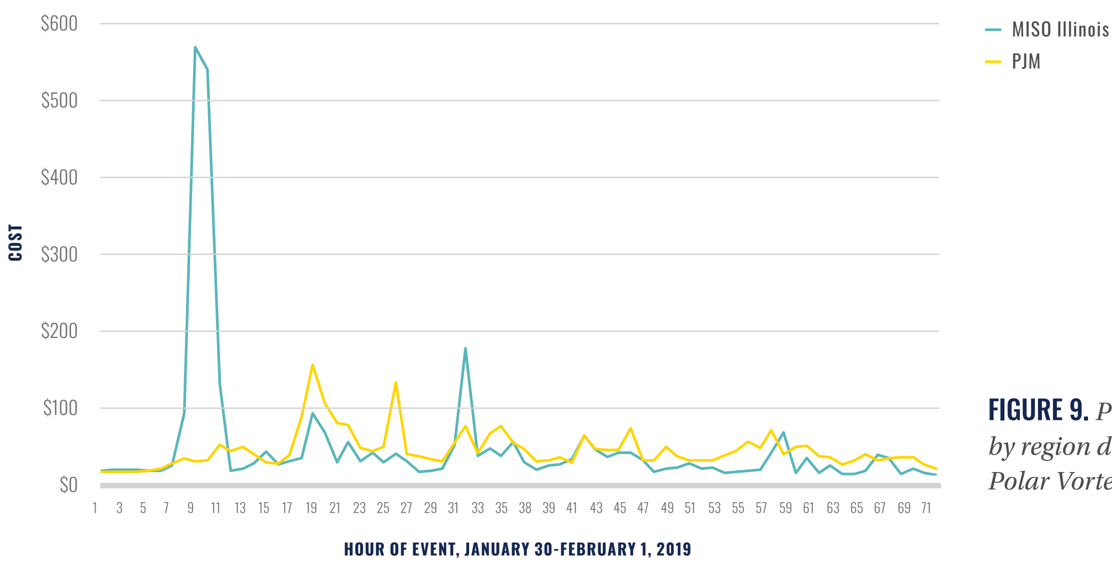


FIGURE 9. *Power prices by region during 2019 Polar Vortex*

This event also revealed other opportunities for expanding transmission to provide consumers with greater access to low-cost energy resources like wind. For example, when MISO and PJM experienced their highest electricity demand on the morning of January 31, SPP had more than 9,000 MW of wind output, keeping prices low. Similarly, electricity prices in MISO South region were consistently low throughout January 30 and 31 because that area was not as affected by the extreme cold. Stronger transmission ties within MISO and between MISO and SPP also could have benefited consumers by providing them with greater access to low-cost electricity generation.

PRO-TRANSMISSION POLICIES TO REALIZE THESE BENEFITS

Like other forms of infrastructure including roads and sewer systems, transmission is often described as a public good in that many of the benefits of transmission cannot be realized by the party making the investment. However, in many parts of the country, generation developers are required to pay for a large share of transmission upgrades. This is much like requiring a driver entering a congested highway to pay the full cost of adding another lane. Policy intervention is therefore needed to correct for the resulting underinvestment in transmission and other public goods. Grid Strategies has labeled the key areas of policy reform needed to enable greater transmission investment, the “three Ps:” planning, paying for, and permitting transmission. Potential policies to correct for the underinvestment in transmission include:

Transmission investment tax credit

A bill has been introduced by Senator Heinrich to create a tax credit to incentivize investments in high-voltage transmission lines.[27] The proposed tax credit is carefully targeted to incentivize high-voltage long-distance transmission projects that are difficult to build but provide large net benefits, but not the smaller local grid upgrades utilities are currently able to plan, pay for, and permit.

A transmission tax credit would provide large net benefits, many times greater than its cost. Many studies have documented the large net benefits of transmission,[28] though those benefits are not typically fully accounted for in transmission planning and cost allocation methodologies.[29] A transmission tax credit particularly benefits lower-income individuals, as electricity bills make up a disproportionate share of their total spending. A federal tax credit is analogous to how federal funds are used to build interstate highways — both account for how those infrastructure investments make the country more resilient against a range of threats and provide economic benefits across broad geographic areas.

27 A Bill to Amend the Internal Revenue Code of 1986 to Establish a Tax Credit for Installation of Regionally Significant Electric Power Transmission Lines, S.1016, 117th Congress, (March 25, 2021), available at: https://www.congress.gov/bill/117th-congress/senate-bill/1016/.

28 For example, see SPP, *The Value of Transmission*, (January 2016), available at: https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf; MISO, *MTEP17 MVP Triennial Review*, (September 2017), available at: https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf; PJM, *The Benefits of the PJM Transmission System*,” (April 16, 2019), available at: https://pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.ashx?la=en.

29 Judy Chang, Johannes Pfeifenberger, and Michael Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, (July 2013), at v, available at: https://cleanenergygrid.org/uploads/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf; Judy Chang, Johannes Pfeifenberger, Samuel Newell, Bruce Tsuchida, and Michael Hagerty, Recommendations for Enhancing ERCOT’s Long-Term Transmission Planning Process, (October 2013), Appendix B, available at: http://files.brattle.com/files/6112_recommendations_for_enhancing_ercot%E2%80%99s_long-term_transmission_planning_process.pdf.

Anchor tenant

Legislation could be enacted to direct the federal government to directly invest in new transmission lines as an "anchor tenant" customer, and then re-sell that contracted transmission capacity to renewable developers and others seeking to use the transmission line. This would help provide the certainty needed to move transmission projects to construction and overcome what is called the "chicken-and-the-egg problem," in which renewable developers and transmission developers are each waiting for the other to go first due to the mismatch in the length of time it takes each to complete construction. The Department of Energy can also use its existing loan-making authority to provide low-cost financing to build transmission.

FERC action

The Federal Energy Regulatory Commission (FERC) has authority over how transmission is planned and paid for. FERC can use that authority to break the transmission planning and cost allocation logjams that are preventing large regional and interregional lines from being built. Specific reforms include developing workable interregional transmission planning and cost allocation methodologies, accounting for transmission's resilience benefits in planning and cost allocation, moving to proactive multi-value transmission planning, and moving away from requiring interconnecting generators to pay for most transmission upgrades. Legislation directing FERC to use these authorities could also be helpful.

FERC could also implement a reliability rule requiring a certain amount of interregional transmission. FERC oversees the North American Electric Reliability Corporation (NERC), which sets and enforces minimum standards for electric reliability. FERC or NERC could require minimum levels for interregional transmission interconnections, recognizing their value for ensuring grid reliability against a range of potential threats. NERC Standard TPL-001 already requires regions to implement solutions, including transmission additions, if their reliability planning studies indicate the system is not resilient against the loss of certain large transmission lines or power plants.[30]

FERC can also develop more workable compensation methods for grid-enhancing technologies that allow more power to be transferred across transmission lines, as this would help to alleviate the economic and reliability impacts of severe weather.

Streamlined permitting

While most authority for permitting transmission lines is held by states, federal agencies have authority over lines that cross federal lands. Steps can be taken to streamline and expedite permitting for transmission, which can currently take a decade or more.

30 NERC, *Standard TPL-001-4 – Transmission System Planning Performance Requirements*, (n.d.), available at: https://www.nerc.com/files/TPL-001-4.pdf.

TECHNICAL APPENDIX

Hourly real-time market prices were obtained from each of the RTOs (MISO,[31] PJM,[32] NYISO,[33] ISO-NE,[34] and ERCOT[35]) for the five severe weather events. Prices for the NYISO Capital zone were used to represent NYISO prices because of significant transmission congestion in the NYC-area zones of NYISO. MISO's Illinois hub was used to represent prices for MISO North, while the Caldwell pricing node in Entergy's Texas footprint was used to represent MISO South during the February 2021 Winter Storm Uri event. TVA-MISO interface prices, obtained from MISO's price dataset, were used to represent TVA prices during the February 2021 Winter Storm Uri and ERCOT 2019 heat wave events. Prices for the ComEd and Dominion zones were used to analyze the prices in western and eastern PJM during the Bomb Cyclone event. Otherwise, average LMPs across the entire RTO were used to represent prices in that RTO.

To calculate the net benefit of transmission reducing power prices by increasing supply on the receiving end of the line during these events, it is also necessary to account for the corresponding price increase caused by the increased demand on generators on the delivering end of the transmission line. The price increase on the delivering end is generally much smaller than the price decrease on the receiving end because the electricity supply curve slopes much more steeply upward when demand is high. For example, the relationship between MISO electricity prices and demand during the January 2014 Polar Vortex event is shown in the chart below. Prices remain relatively low until demand exceeds 90 GW, at which point prices ramp up dramatically as demand increases. As a result, delivering an additional GW from a region with low demand will not dramatically raise prices there, while prices will be dramatically reduced in the receiving region where demand is high.

31 MISO, "Historical Annual Real-Time LMPs," (n.d.), available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AHistorical%20Annual%20Real-Time%20LMPs%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc.

32 PJM, "Settlements Verified Hourly LMPs," (n.d.), available at: https://dataminer2.pjm.com/feed/rt_da_monthly_lmps.

33 NYISO, "Real-Time Market LBMP – Zonal," (n.d.), available at: https://www.nyiso.com/custom-reports?report=rt_lbmp_zonal.

34 ISO New England, "Final Real-Time Hourly LMPs," (n.d.), available at: https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/lmps-rt-hourly-final.

35 ERCOT, "Historical RTM Load Zone and Hub Prices," (n.d.), available at: http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13061&reportTitle=Historical%20RTM%20Load%20Zone%20and%20Hub%20Prices&showHTMLView=&mimicKey.

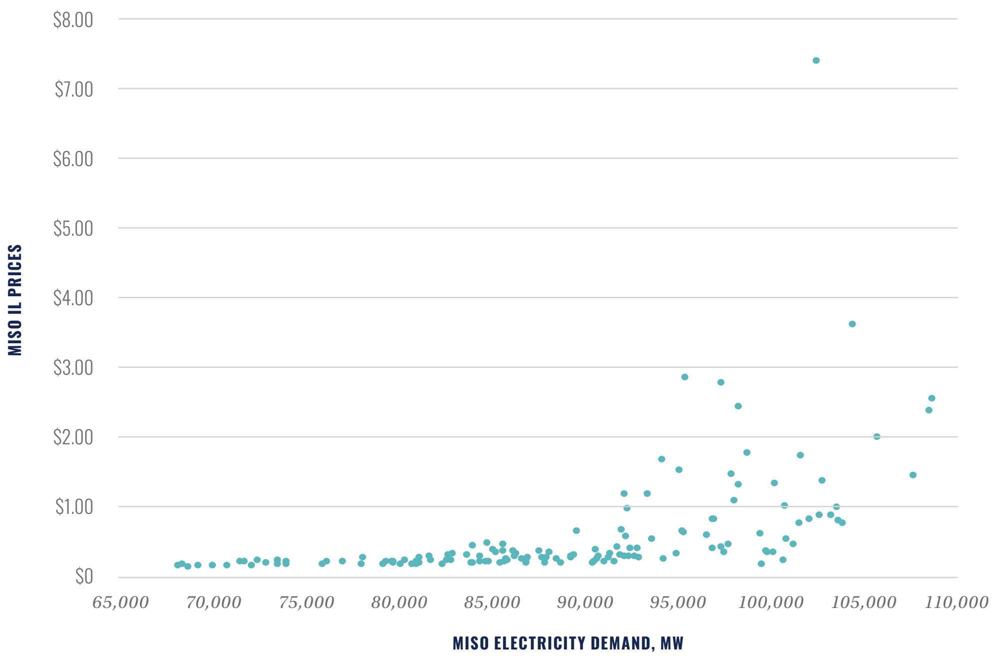


FIGURE 10. *Relationship between MISO demand and power prices during 2014 Polar Vortex*

Demand data for MISO,[36] TVA,[37] and other delivering regions were combined with the price data obtained earlier to create similar scatterplots for those delivering regions. Two linear best-fit slopes were added to each scatterplot, one on the flat part of the slope for periods of low demand, and one on the steep part of the slope for periods of high demand. For example, for the chart above, when MISO demand is greater than 90 GW, the linear best-fit slope indicates that an additional GW of demand increases prices by $15.30/MWh; however, when demand is less than 90 GW, each GW of demand increases prices by only $0.80/MWh. Those linear functions were then used to model the increase in prices in the delivering region, starting from actual demand and prices and then increasing demand by 1 GW to account for exports using the new transmission. This accounts for how increasing demand on the delivering end of the transmission slightly reduces the benefits of transmission.

36 MISO, "Historical Daily Forecast and Actual Load by Local Resource Zone," (n.d.), available at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3AHistorical%20Daily%20Forecast%20and%20Actual%20Load%20by%20Local%20Resource%20Zone%20(xls)&t=10&p=0&s=MarketReportPublished&sd=desc.

37 EIA, "Demand for Tennessee Valley Authority (TVA), Hourly – UTC Time," (n.d.), available at: https://www.eia.gov/opendata/qb.php?category=3390009&sdid=EBA.TVA-ALL.D.H.

EXHIBIT 5

Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits

September 9, 2021

Submitted to: American Council of Renewable Energy (ACORE)

Submitted by: ICF Resources, LLC. Fairfax, VA

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Additionally, ICF team is grateful for the detailed comments from Daniel Hall, Central Region Senior Director, Electricity & Transmission, American Clean Power Association and Kevin O'Rourke, VP, Strategic Partnerships & Public Affairs, American Council on Renewable Energy.

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LIST OF EXHIBITS

LIST OF ABBREVIATIONS

ACORE	American Council on Renewable Energy
APC	Adjusted Production Cost
ARR	Annual Revenue Requirements
B/C	Benefit to Cost
DFAX	Distribution Factor
DISIS	Definitive Interconnection System Impact Study
DPP	Definitive Planning Phase
GI	Generation Interconnection
ISO	Independent System Operator
IRP	Integrated Resource Plan
ITP	Integrated Transmission Planning
LOIS	Limited Operation Interconnection Study
LRZ	Local Resource Zone
MCPS	Market Congestion Planning Study
MEP	Market Efficiency Project
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Project
NPV	Net Present Value
OATT	Open Access Transmission Tariff
RPS	Renewable Portfolio Standards
RRF	Regional Resource Forecast
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SPP	Southwest Power Pool
WACC	Weighted Average Cost of Capital

ABOUT ICF

ICF is a global consulting services company with over 7,000 specialized experts, but we are not your typical consultants. At ICF, business analysts and policy specialists work together with digital strategists, data scientists and creatives. We combine unmatched industry expertise with cutting-edge engagement capabilities to help organizations solve their most complex challenges. Since 1969, public and private sector clients have worked with ICF to navigate change and shape the future.

We bring together local, regional and industry experience to help through the entire lifecycle of a project from evaluation of site constraints and opportunities to engineering due diligence and advice financiers, developers, and government clients investing in renewable energy projects and new technologies.

We have decades of experience building relationships with federal, state, and local agencies for seamless coordination on large projects with complex permitting. In assessing individual assets or portfolios, our breadth of due diligence and litigation experience allows us to make connections amongst converging markets, emerging technologies, evolving policy and regulations, and operational realities relevant to financial markets.

ICF is trusted throughout the industry to provide independent, fact-based research and opinions on power, environmental, and policy topics. Through transparency in our review and analysis, we ensure our commitment to independence and credibility, bringing projects to their ideal fruition.

1. EXECUTIVE SUMMARY

The American Council on Renewable Energy (ACORE), with support from the Macro Grid Initiative and in collaboration with American Clean Power Association, engaged ICF Resources, LLC (ICF) to evaluate the regional economic benefits of transmission network upgrades necessitated by generation interconnection requests in the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) wholesale power markets. Both markets have seen a significant uptick in renewable generation interconnection requests over the past few years. Currently, over 92% of the 79 gigawatts (GW) of active requests in the MISO generation interconnection queue are solar, wind, and hybrid resources.[1] In SPP, solar, wind, and hybrid resources make up 95% of the 103 GW active queue requests.[2] Renewable generation is expected to grow even more in the coming years as favorable economics and clean energy goals continue to drive demand.

The lowest cost energy resources, such as solar and wind, are often located far from load centers, thus requiring transmission capacity expansion to move the power from the generation sources to the location it is needed. MISO's MVP and SPP's priority projects have been instrumental in integrating over 20 GW of new renewables across MISO and SPP. The transmission headroom created by these high-voltage expansion plans appears to have been used up and neither of the system operators have current board-approved plans for any significant regional transmission projects to enable new generation. Requests for new wind and solar generation interconnection have increased exponentially to avail the federal tax incentives; this increase is also due to a steady decline in the cost of wind and solar energy as states and corporate buyers seek to meet their renewable standards and goals.

In both markets, the cost of transmission network upgrades has become a significant hurdle for the integration of low-cost new renewable generation. For example, in its most recent Definitive Interconnection System Impact Study (DISIS) for generator interconnection, SPP identified the need for over $4.6B[3] worth of transmission network upgrades to help interconnect 10.4 GW of generation. If developed, these upgrades would have cost approximately $448/kW.[4] Similarly, in its most recent Definitive Planning Phase (DPP) study for generator interconnection, MISO identified the need for nearly $2.5B[5] worth of transmission network upgrades to interconnect 9.2 GW of generation in MISO South that translates to approximately $271/kW. The upgrades assigned to the generators are not limited to direct interconnection costs (akin to a

> Most recent system impact studies from SPP and MISO show network upgrade costs in the range of $270/kW to $448/kW.

[1] MISO GI queue as of August 18th, 2021 – does not include projects from DPP-2021 queue.
[2] SPP GI queue as of August 19th, 2021 – includes projects proposed in DISIS-2021 cluster.
[3] Source: DISIS-2017-001 published on April 28, 2021.
[4] Calculated by dividing the $4.6B in network upgrade costs by 10.4 GW of generator interconnection requests that were allocated the upgrade costs.
[5] Source: DPP-2019 Phase 1 published on July 16, 2020.

driveway) that allow them to access the high-voltage transmission (the highway). Given the over-subscribed power grid, interconnection customers are being allocated the full cost of adding new lanes to the highway and are increasingly responsible for building new highways. For example, SPP in its DISIS -2017-001 included a 165-mile, $1.34B, double circuit 765 kV line.[6]

Adding to the challenge is the fact that both markets allocate most, if not all, of the network upgrade costs to the generation developer. Under MISO's cost allocation process, almost all the costs of network upgrade projects rated 345 kV and higher are assigned directly to generators. Developers are responsible for 90% of the cost, with the remaining 10% allocated regionally on a postage stamp basis. Developers are responsible for all the costs for network upgrades rated below 345 kV. In SPP, the entire cost of network upgrades is assigned directly to generators. This cost allocation fails to consider potential regional economic benefits from these network upgrades.

Current Approach	Load	Generator
SPP	0%	100%
MISO	10% (>=345 kV)	90% (>=345 kV)
	0% (<345 kV)	100% (<345 kV)

Using very conservative assumptions, this study evaluated the economic benefits of a representative sample of network upgrade projects[7] assigned through the MISO and SPP GI process over the last seven years. ICF screened nearly 230 network upgrades spanning four DISIS studies (2014 – 2017) for SPP and 433 network upgrades spanning four DPP studies (2016 – 2020) for MISO. Informed by a range of factors, including voltage class, location of the upgrades, and level of generation interconnection capacity that were allocated the network upgrades, and in consultation with MISO and SPP staff, the screened network upgrades across both RTOs were shortlisted to six network upgrades in each RTO. In this report, capacity of the set of generators allocated the cost of a network upgrade is referred to as the GI capacity associated with that network upgrade. Exhibit 1 shows the geographic location of the selected projects. The results demonstrate that several of the somewhat randomly selected network upgrades provide significantly more benefits relative to the current costs allocated to the shared system.

To the extent possible, methodologies, assumptions, and processes employed by both MISO and SPP in their respective economic planning processes were followed in the study. The study design, including screening process and criteria to shortlist, was shared with MISO and SPP staff. The final set of shortlisted network upgrades was made after consultation with MISO and SPP.

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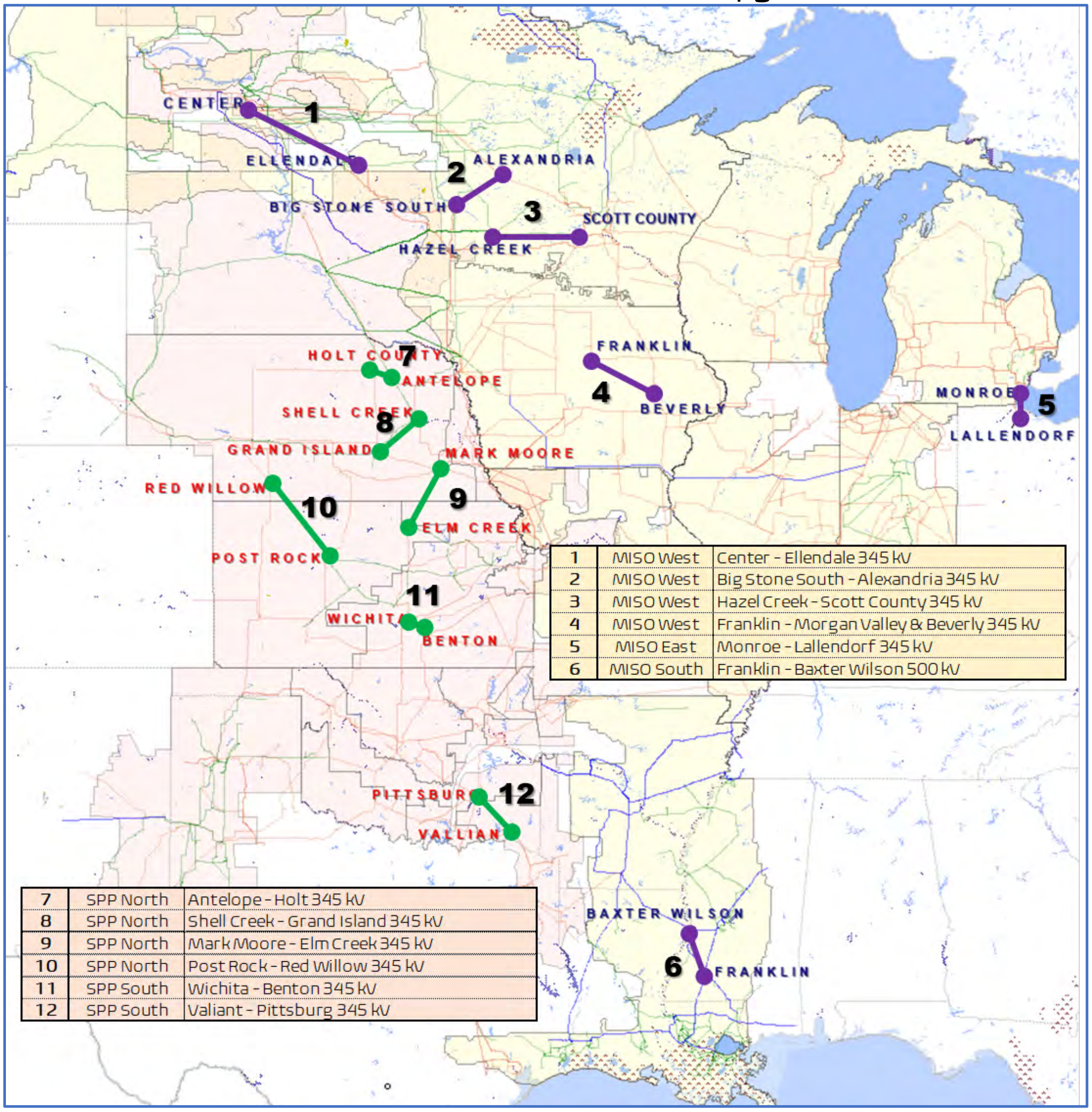
[6] Crawfish Draw - Seminole 765 kV (165 miles) | Crawfish Draw - Crossroads (95 miles).

[7] ICF relied on past DISIS and DPP studies for SPP and MISO respectively to shortlist a pool of network upgrades that was evaluated as part of the study. The details of the screening processes are described in Study Design section of the report.

Exhibit 1: MISO and SPP Network Upgrades



1.1. Key Findings

A summary of the 12 network upgrades (NU) in MISO and SPP and the benefits and costs associated with those network upgrades are shown in Exhibit 2. Benefits of the shortlisted network upgrades are calculated as the Adjusted Production Cost (APC) savings (or "Benefits") to the shared system. APC is one of the key metrics used to calculate economic benefits in both MISO and SPP, as well as in other major electricity markets.

Consistent with the MISO and SPP planning processes, APC savings and costs were assessed over 20-year and 40-year study periods, respectively. In addition, the table provides the percentage of generator interconnection (GI) builds associated with each of the network upgrades that are represented in MISO's and SPP's planning scenarios, which impact the resulting benefits calculation.

Exhibit 2: Summary of Findings

Region	NU #	Network Upgrade	GI Capacity [8] Y2 / Y5 / Y10 / Y15[9]	Cost[10]	APC Savings (Benefits)[11]	B/C[12]
MISO West	1	Center – Ellendale 345 kV	- / 0% / 71% / 71%	$456.2M	$181.9M	0.40
MISO West	2	Big Stone South – Alexandria 345 kV	- / 30% / 97% / 97%	$221.4M	$335.8M	1.52
MISO West	3	Hazel Creek – Scott County 345 kV	- / 10% / 24% / 24%	$236.4M	$85.4M	0.36
MISO West	4	Franklin – Morgan Valley & Beverly 345 kV	- / 33% / 92% / 92%	$597.4M	-$4.8M	-
MISO East	5	Monroe – Lallendorf 345 kV Rebuild	- / 0% / 5% / 5%	$44.9M	$2.9M	0.06
MISO South	6	Franklin – Baxter Wilson 500 kV	- / 21% / 44% / 47%	$350.5M	$41.1M	0.12
SPP North	7	Antelope – Holt 345 kV	0% / 82% / 90% / -	$276.6M	$142.8M	0.52
SPP North	8	Shell Creek – Grand Island 345 kV	0% / 100% / 100% / -	$208.7M	$61.7M	0.30
SPP North	9	Mark Moore – Elm Creek 345 kV	0% / 89% / 96% / -	$259.3M	$10.4M	0.04
SPP North	10	Post Rock – Red Willow 345 kV	0% / 72% / 100% / -	$345.8M	-$8.9M	-
SPP South	11	Wichita – Benton 345 kV 2nd Line	0% / 90% / 97% / -	$32.1M	$59.3M	1.85
SPP South	12	Valiant – Pittsburg 345 kV 2nd Line	0% / 90% / 97% / -	$282.9M	$86.2M	0.30

APC Savings

Ten of the 12 network upgrades assessed in this study provided positive APC benefits. In general, of the network upgrades modeled, those with a higher percentage of interconnection projects represented in the associated future scenario resulted in higher APC savings. Six of the nine network upgrades modeled where 70% or greater of the same or similarly placed GI capacity was matched with RTO planning models resulted in

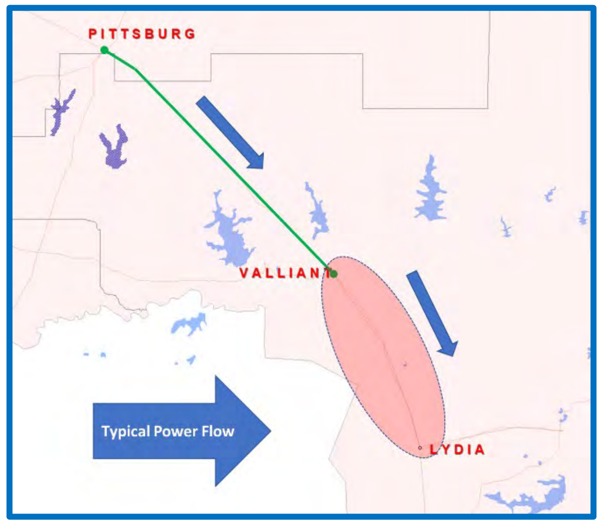
Production cost savings for six network upgrades with greater than 70% percent of GI capacity associated with those represented in the RTO planning models ranged between $59M and $335M.

[8] Percent capacity of the total GI projects associated with each of the network upgrades that is represented in the RTO Planning Scenarios.
[9] MISO's model run years: Y5 (2025), Y10 (2030), Y15 (2035) | SPP's model run years: Y2 (2023), Y5 (2026), Y10 (2031)
[10] Cost represents the 20-year (for MISO) or 40-year (for SPP) total costs of each network upgrade.
[11] Benefits represent adjusted production cost (APC) savings attributed to the new transmission project. For MISO network upgrades, the APC savings represent the 20-year NPV while the APC savings represent the 40-year NPV for SPP network upgrades.
[12] Calculated as benefits divided by cost for each transmission project. A ratio greater than 0.1 in MISO and 0 in SPP indicates that benefits to the consumer exceeds cost allocated to them.

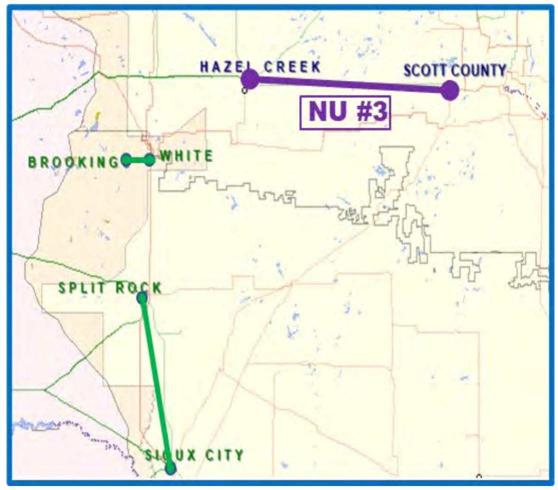
significant benefits—with a range of $59M to $335M in benefits to the shared system. Specifically, Center – Ellendale (NU #1), Big Stone South – Alexandria (NU #2), Antelope – Holt (NU #7), Shell Creek - Grand Island (NU # 8), Wichita - Benton (NU #11), and Valiant - Pittsburg (NU #12) demonstrated high APC savings due to significant share of GI capacity in the planning models. Other upgrades with a lower percentage match, such as Monroe – Lallendorf (NU #5) and Franklin – Baxter (NU #6) with only 5% and 47% of the associated GI capacity respectively, showed diminutive benefits.

Higher GI capacity representation in the planning models was not the only driver of APC savings. Several other factors affected the level of observed APC savings. These are:

- **Increase in congestion on transmission lines in the vicinity of the upgrade after implementation of the upgrade.** For example, nearly all the generation interconnection projects associated with the Valliant – Pittsburg 345 kV (NU #12) network upgrade were represented in the case by the final run year. However, the upgrade provided limited benefits because transmission expansion along the Valliant – Pittsburg corridor created new congestion downstream of the line. With the inclusion of the network upgrade, Valliant – Lydia 345 kV line became congested. Because the scope did not include upgrades to additional facilities identified in the DISIS studies, the impact of the network upgrade was limited. SPP identified Valliant – Lydia 345 kV as a network upgrade in the same DISIS study cluster. Similarly, Mark Moore – Elm Creek (NU #9) resulted in increased congestion on the Columbus 345/138 kV transformer downstream of the network upgrade that resulted in negative APC savings.



- **Upgrades in locations with frequent and persistent congestion provided benefits even with relatively lower percentage of associated generation interconnection projects.** For example, Hazel Creek – Scott County 345 kV (NU #3) showed relatively high benefits with only 24% of the associated generation interconnection projects. Higher APC savings despite a lower level of associated generation was observed due to mitigation of pre-existing chokepoints on Brooking – White and Split Rock – Sioux City 345 kV lines.



B/C Ratio

Of the ten network upgrades with positive APC savings, the benefit-to-cost (B/C) ratios ranged from a low of 0.04 for the Mark Moore – Elm Creek 345 kV network upgrade in SPP to a high of 1.85 for the Wichita – Benton 345 kV network upgrade in SPP. Seven network upgrades had B/C ratios greater than or equal to 0.30. The results show that many projects provide significant regional economic benefits, and some even more than the costs. For example, the Big Stone – South Alexandria 345 kV in MISO and Wichita – Benton 345 kV in SPP have the potential to provide benefits that far exceed the cost to the system.

The network upgrades provide benefits to the system by enabling more low-cost renewable output, which leads to reduction in fossil-fired generation and associated emissions attributed to those generators. On average, the network upgrades enabled 12 TWh of additional renewable output in MISO and nearly 7 TWh of additional renewable output in SPP. The network upgrades also eased existing chokepoints in SPP and MISO, which is beyond their primary purpose of integrating renewables.

1.2. Conservative Aspects of Key Study Assumptions

As noted above, the current cost allocation processes in MISO and SPP largely ignore the economic benefits to the shared system from these network upgrades. This study examined a selection of proposed network upgrades in the two regions to determine their potential to provide benefits associated with APC savings. It assumed network upgrades would be built primarily to interconnect the associated generation resources. Aspects of transmission planning that could enhance market efficiency benefits were not incorporated explicitly. In particular, the study was designed to test the one-off addition of single network upgrades. The only difference between the Reference Case and each of the change cases was the addition of a single transmission network upgrade. As a result, the economic benefits evaluated and described in this report are conservative and may understate the full benefits of the projects to consumers.

Following are other examples of the conservative methods employed in the study. Sensitivity cases, which are described in greater detail below, were conducted to demonstrate the extent of the actual benefits if these factors were taken into consideration.

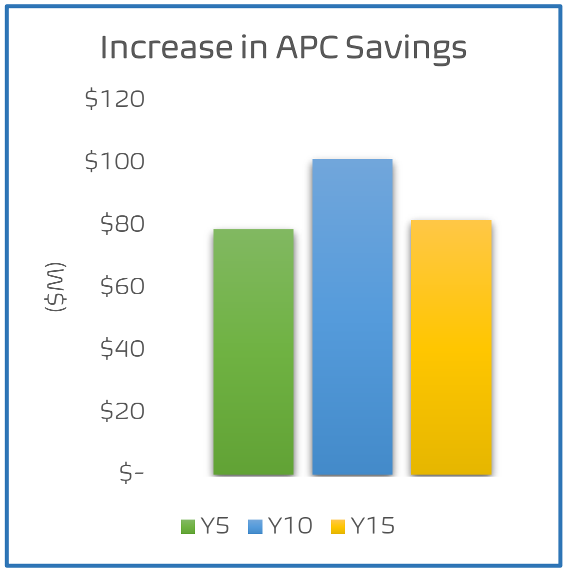
1. **Selection of network upgrade projects.** Unlike typical planning for market efficiency projects, the network upgrades in this study were not selected based on their ability to address persistent congestion. Any economic benefits calculated in this study is incremental to the benefits of interconnecting and delivering low-cost renewable energy to consumers.

2. **Choice of future scenarios.** The study used the most conservative of the MISO and SPP future scenarios. In MISO, the study used Future I, which factored in carbon emissions reduction[16] of 40%. Future II and Future III reflected 60% and 80% carbon emissions reduction respectively and had significantly higher renewable generation. For SPP, the study used Future I that reflected the continuation of current industry trends and environmental regulations. It assumed that solar and wind additions will exceed current renewable portfolio standards due to economics, public appeal, and the anticipation of potential policy changes.[17] Increasing renewable generation increases the benefits of the network upgrades. This also demonstrates another type of unrecognized benefit of network upgrades. Once built, these upgrades would enable additional generation to enter the queue in the future and interconnect at no incremental cost to the future builds or consumers.[18]

Renewable Build-Out (MW)[13]	MISO[14]	SPP[15]
Future 1	48.8 GW	15.5 GW
Future 2	58.4 GW	22.5 GW
Future 3	114.8 GW	N/A

[13] Only wind and solar resources are reflected in the totals.
[14] Futures resource additions through 2035 | source: MISO Futures Report dated April 2021.
[15] Future resource additions through 2031 | source: 2021 Integrated Transmission Planning Resource and Siting Plan
[16] Carbon emissions reduction refer to power sector emissions reduction from 2005 baseline – Source: MTEP21 Futures White Paper dated April 27, 2020.
[17] 2021 Integrated Transmission Planning Assessment Scope document dated August 5, 2020.
[18] FERC ANOPR has acknowledged the issue and raised the concern of potential free-rider problems associated with interconnection customers that later connect to transmission facilities planned for anticipated future generation.

3. **The benefit of the network upgrades therefore includes the ability to enable the full output of the generation interconnection projects.** Because the scope of this study was limited to one-off additions of network upgrades, the associated generation resources were not derated in the Reference Case without the network upgrade. This approach significantly understates the actual production cost savings associated with each network upgrade. A sensitivity was conducted to demonstrate the effect of this assumption on the APC savings associated with Franklin – Baxter Wilson 345 kV line.[19] As discussed above, this line provides relatively low net benefits in the reference scenario. However, in the de-rate scenario, in which 92% of renewables assigned to the network upgrades are excluded from the Base Case and only assumed in the Change Case along with the network upgrade that is being evaluated, APC savings increased by an average of nearly $87M and yielded a B/C ratio to 2.03 (as compared with 0.12 in the reference case).



4. **Absence of associated network upgrades.** MISO and SPP generation interconnection studies usually identify multiple network upgrades to enable the full capacity of each cluster of generation interconnection projects. Because the study was designed to assess one-off additions of single network upgrades, additional projects identified in the interconnection studies were not implemented. This lack of additional upgrades identified in the interconnection studies was observed to be a key factor in the negative APC savings for Franklin – Morgan Valley & Beverly 345 kV (NU#4) and Pittsburg – Valliant 345 kV (NU#12). When simulated as one-offs, these network upgrades led to increased congestion on other transmission facilities that had been identified in the SPP and MISO interconnection studies. For example, the Valliant – Pittsburg 345 kV upgrade created new congestion downstream on the Pittsburg – Valliant 345 kV line. With the inclusion of the network upgrade, Valliant – Lydia 345 kV line became congested. Congestion was observed on Mingo to Post Rock 345 kV, which is one of the eight network upgrades and attributed to be the main driver of negative APC savings for Post Rock – Red Willow 345 kV.

5. **Associated generation interconnection projects.** On average, just under 50% of the builds associated with the network upgrades were represented in the MISO

[19] In MISO, generators that interconnect prior to completion of required network upgrades are subject to quarterly operating limits that ensure they do not cause any reliability violations. SPP performs an annual Limited Operation Interconnection Study (LOIS) to determine the impacts of interconnecting to the transmission system before all required Network Upgrades identified in the DISIS studies can be placed into service.

Future 1, while a higher capacity (above 80%) were found to be associated with the shortlisted network upgrades in SPP. To avoid biasing the study, no additional capacity was added to the ISO models. As a result, some associated generation interconnection projects that could drive the usage and benefits of network upgrades were excluded from the study.

2. INTRODUCTION

The American Council on Renewable Energy (ACORE), with support from the Macro Grid Initiative and in collaboration with American Clean Power Association, engaged ICF Resources, LLC (ICF) to evaluate the regional economic benefits of transmission network upgrades necessitated by generation interconnection requests in the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) wholesale power markets.

In both markets, the cost of transmission network upgrades has become a significant hurdle for the integration of low-cost new renewable generation. The upgrades assigned to the generators are not limited to direct interconnection costs (akin to a driveway) that allow them to access the high-voltage transmission (the highway). Given the over-subscribed power grid, interconnection customers are being allocated the full cost of adding new lanes to the highway and increasingly building new highways. Adding to the challenge is the fact that both markets allocate most, if not all, of the network upgrade costs to the generation developer. This cost allocation fails to consider potential regional economic benefits from these network upgrades. Using very conservative assumptions, this study evaluated the economic benefits of a representative sample of network upgrade projects assigned through MISO and SPP's GI process over the last seven years.
The remainder of the report is organized into four sections. Section 3 provides a market overview of the SPP and MISO markets. Section 4 details the overall study design and underlying assumptions for the assessment of benefits. Section 5 provides results of the ICF assessment including production cost savings and B/C ratio for each of the twelve projects followed by conclusions in Section 6.

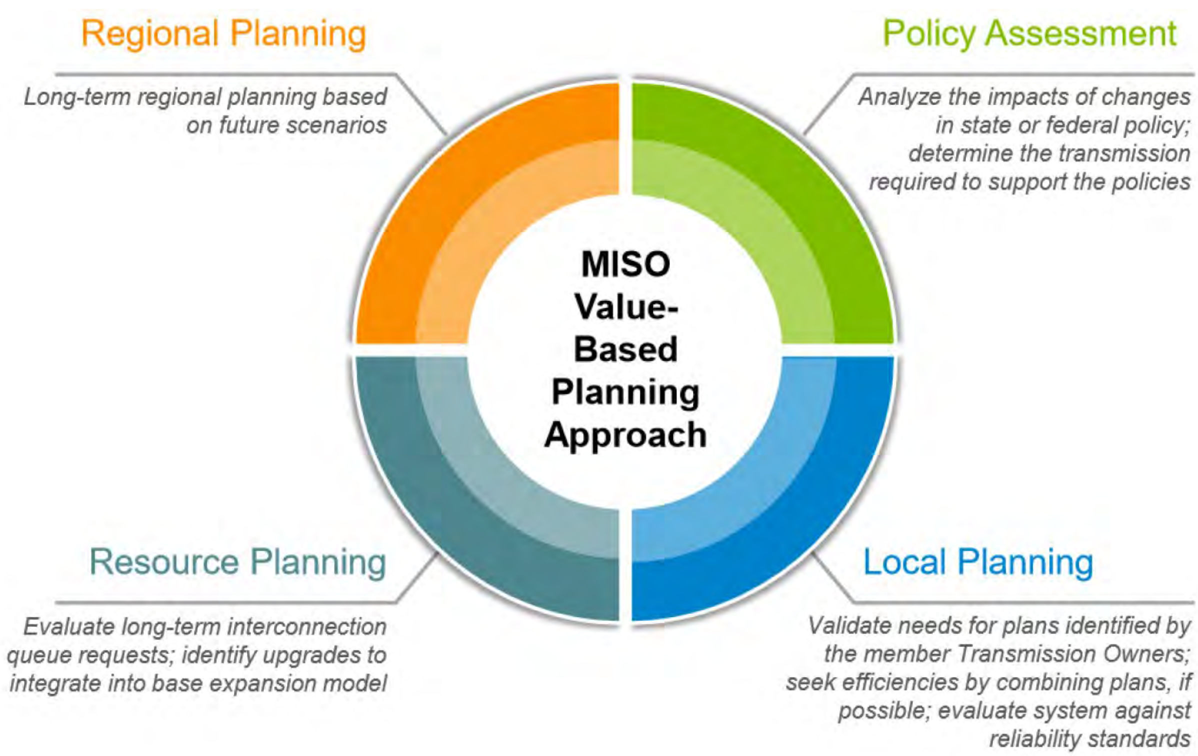
3. MARKET OVERVIEW

3.1. Midcontinent Independent System Operator (MISO)

MISO, the largest wholesale market in North America from a geographical standpoint, is amid an aggressive transition towards a cleaner generation portfolio. MISO has shifted from a coal heavy portfolio in 2014 (57%[20] of the generation mix was comprised of coal) to a current portfolio largely comprised of gas and renewables (over 60%[21] of the generation mix).

As the transition towards a cleaner generation mix continues, it is imperative to focus on a holistic approach to grid planning and management that would enable the greatest benefits to consumers. MISO's value-based planning process incorporates regional planning, local planning, resource planning, and changes in policies that ultimately ensures reliability and minimizes costs to its customers. This switch to a value-based planning could potentially address the deviation between generator interconnection studies versus transmission planning studies. The exhibit below shows MISO's concept of this value-based approach.

Exhibit 3: MISO's Value-Based Planning Approach



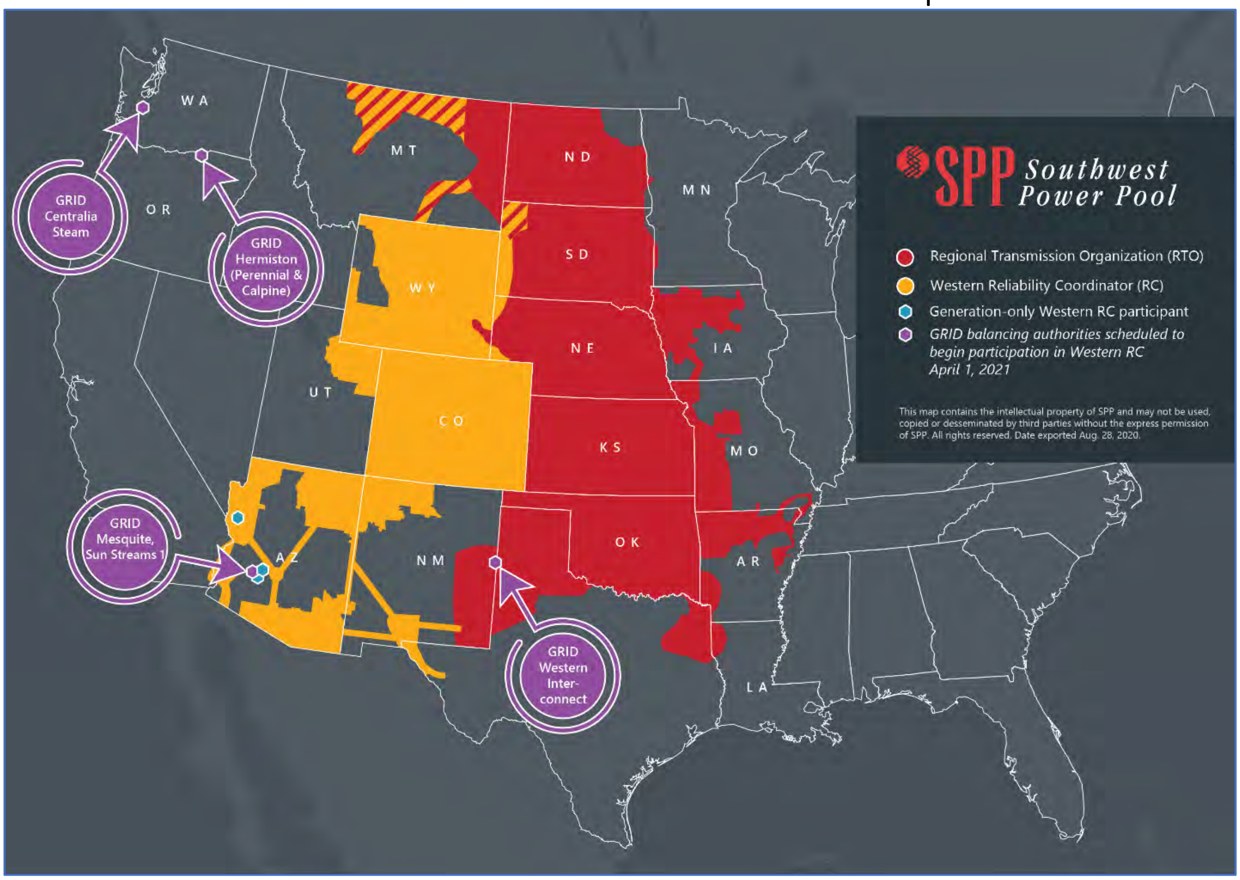
Source: [MTEP 2021 Report](#) – Executive Summary

[20] http://timeline.misomatters.org/
[21] https://www.misoenergy.org/about/media-center/corporate-fact-sheet/

3.2. Southwest Power Pool (SPP)

SPP, one of the seven Independent System Operators (ISOs)/Regional Transmission Organizations (RTOs) in the United States, oversees the bulk electric grid and wholesale power market in the central United States on behalf of a diverse group of utilities and transmission companies in 17 states (including 3 states that comprise the Western Energy Imbalance Service market).[22] Through its portfolio of Western Energy Services, SPP also provides contract-based services like reliability coordination and administration of a real-time balancing market to customers in the Western Interconnection.

Exhibit 4: SPP RTO Market and Western RC Footprint



Source: https://spp.org

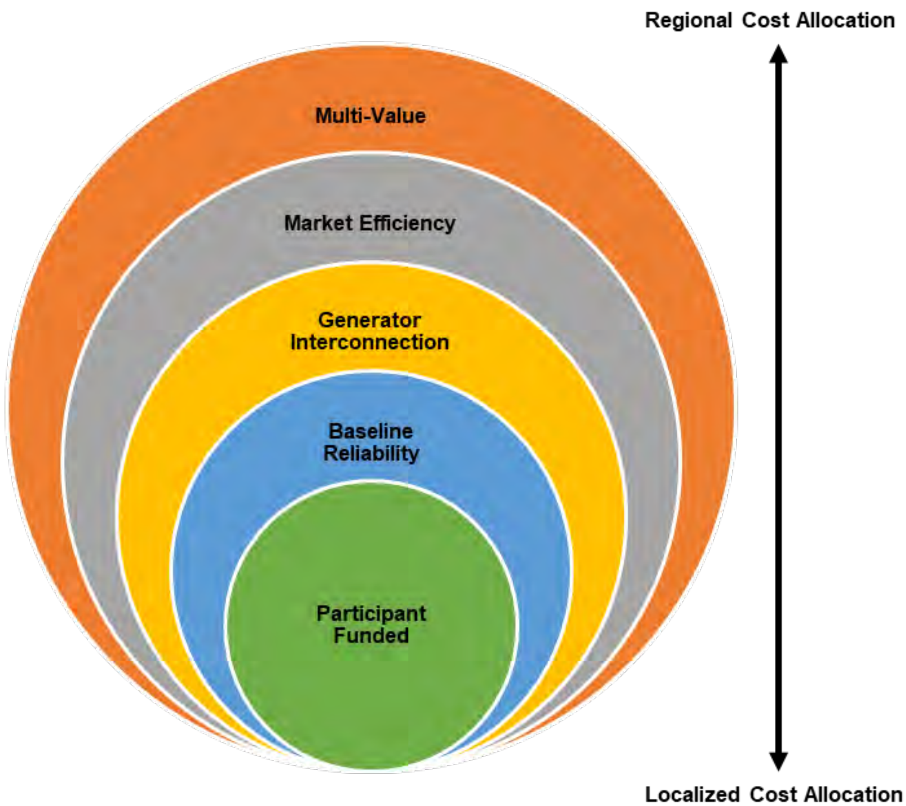
In the Eastern Interconnection, SPP's transmission network consists of approximately 70,000 miles of high-voltage transmission lines and it administers a total generation capacity of over 90 GW. Over the years, SPP's members have harnessed the wind-rich region of the Midwest that has contributed to a shift in the generation mix. As of January 2021, wind comprised 29% of SPP's generating capacity and nearly 30% of its energy production. In March of 2021, SPP saw record wind penetration in real-time at nearly 82%.

[22] https://spp.org

3.3. MISO's Planning Process

MISO's Transmission Expansion Planning (MTEP) process is an annual process that evaluates various types of projects to help support local and regional reliability needs, help facilitate interconnection of generation resources, and offer a platform for developing competitive transmission projects providing regional benefits. MISO's MTEP process classifies projects into several categories, each with its own drivers and needs, and is cost allocated based on the benefits it is intended to provide. Exhibits 7 and 8 below provide an overview of the different categories of MTEP projects and how these projects are cost allocated.

Exhibit 5: MTEP Categories



Source: MISO Tariff – Attachment FF

Exhibit 6: MISO Project Types

Project Type	Description	Cost Allocation Methodology
Multi-Value Projects (MVPs)	Often address one or more of the following three goals and are evaluated as part of a portfolio of projects whose benefits (and costs) are spread across the footprint. • Reliably and economically enable regional public policy needs • Provide multiple types of regional economic value • Provide a combination of regional reliability and economic value	100% postage stamp to load
Market Efficiency Projects (MEPs)	Often provide benefits that span beyond the local zone and is regionally cost-allocated that is commensurate to the load-ratio share of the members	230 kV and above[23]: distributed to Local Resource Zones (LRZs) commensurate with expected benefit
Generation Interconnection (GI) Projects	Help mitigate potential constraints that are caused by interconnecting generator resources to MISO's footprint and is predominantly paid by the interconnection customer.	Primarily funded by the requestor
Baseline Reliability Projects	Projects that are proposed to meet NERC's Transmission Planning Standards and is cost allocated amongst the local zone since the benefits of the project are often localized.	100% allocated to local TPZ
Participant Funded Projects	Often addresses localized constraints	Primarily funded by the requestor

Source: Transmission Planning OMS Cost Allocation Principles Committee (CAPCOM) presentation dated October 19, 2020

3.4. SPP's Planning Process

To meet its Open Access Transmission Tariff (OATT), SPP conducts the Integrated Transmission Planning (ITP) Assessment to plan transmission upgrades needed to maintain reliability, provide economic benefits, and achieve public policy goals over a 10-year planning horizon. In addition, SPP also performs 20-year assessment every five years that focuses on identifying the need for extra high-voltage transmission lines (345 kV and above) for a 20-year planning horizon. The study's success depends on its ability to provide a robust system that enables transmission usage and generation access. The assessment identifies a versatile transmission system capable of providing cost-effective energy delivery for a broad range of possible generation resource futures.[24]

[23] FERC approved MISO's Transmission Cost Allocation reforms in July 2020 that lowered the voltage threshold for MEP projects to 230 kV, added two new metrics in calculating the Adjusted Production Cost (APC) savings, and eliminated the allocation of 20% of the cost of MEPs to the entire MISO footprint on a postage-stamp basis.
[24] Source: spp.org

With the ever-increasing penetration of renewables, SPP updated its renewable forecast in the ITP assessment to allow the region to proactively build the infrastructure needed to alleviate congestion and provide access to cheaper energy.[25] SPP considers three distinct scenarios to account for variations in system conditions over a 10-year period. These scenarios consider requirements to support firm deliverability of capacity for reliability while exploring rapidly evolving technology that may influence the transmission system and energy industry. The scenarios include varied wind projections, utility-scale and distributed solar, energy storage resources, generation retirements and electric vehicles. In addition to the scenarios, SPP also analyzes a wide range of sensitivities that consider changes to natural gas prices, generator retirements, renewables development, battery storage and demand.

SPP has seen significant wind generation capacity expansion over the last several years, driven by a combination of strong wind resources, production tax credits, and availability of power purchase agreements and hedges. SPP's wind penetration stands at over 23 GW; the 2nd largest market share of wind within the United States, behind ERCOT. There has also been a strong growing interest in solar development in the last few years as evident by the active queue requests. SPP currently has Approximately 46 GW of active solar projects in its Generation Interconnection Queue.[26]

While large load centers in SPP's footprint are in the eastern parts of the market, the southwestern portion comprising the Texas panhandle, western Oklahoma, and southwestern Kansas boast high wind resources. The power often flows from these wind rich regions in the southwest and from the north to load centers in the east.

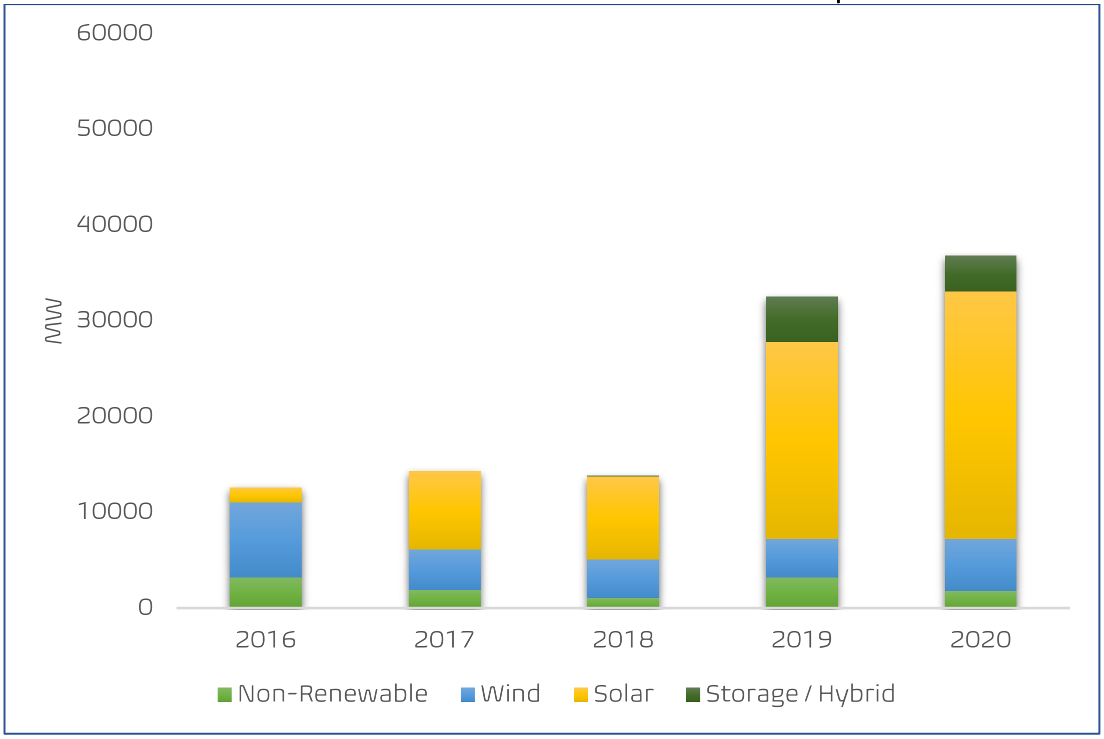
Similar to MISO's MVP, SPP's board approved the construction of a group of "priority" high-voltage electric transmission projects estimated to provide benefits of nearly $4B to the SPP region over 40 years.[27] This group of projects increased the transfer capability and allowed for additional transmission service requests to be granted. In addition, between 3 GW and 5 GW of wind energy (as well as new non-renewable generation) has resulted from this group of projects. However, the incremental transmission capacity created by the "priority" projects are all but used.

3.5. Generator Interconnection Process in MISO and SPP

Over the last few years, generator interconnection queues across the country have seen significant uptick in renewable generation requests. Since 2016, as shown in Exhibits 9 and 10, the Midcontinent Independent System Operator (MISO) has seen renewables comprise of nearly 90% of the interconnection queue on average. While wind interconnection requests have steadily increased over the years in MISO, the solar interconnection requests have increased exponentially.

[25] Source: 2020 ITP Report
[26] SPP Generation Interconnection Queue as of June 2021.
[27] https://www.spp.org/engineering/transmission-planning/priority-projects/

Exhibit : Active and Executed Generator Interconnection Requests (2016-2020)[28]



Source: MISO Generator Interconnection Queue

The significant increase in renewable share brings with it a pressing need for new or expanded transmission grid. The current transmission grid was built years ago to accommodate conventional generators that were often sited close to the load. Renewables, however, are often developed further away from load (largely due to land availability) and rely on transmission reinforcements to help transmit power. This is evident with the ever-increasing transmission network upgrade costs that are seen in markets that eventually leads to several interconnection projects withdrawing their requests.

As the MISO and SPP footprints continue to integrate renewables, there is a growing need to upgrade the existing transmission system to better facilitate the transfer of power from generators to load centers. In its most recent generator interconnection study for example, SPP identified the need for over $4.6B[29] worth of transmission upgrades to help interconnect 10.4 GW of generation. SPP's network upgrades are entirely participant funded, so all these costs will be allocated to the renewable generation developers. The high upgrades costs are sure to deter several interconnection customers from staying in the queue. In addition to the high network upgrade costs, delays to SPP's DISIS process creates uncertainty for interconnection customers. SPP is currently evaluating generators that entered the queue in March 2017. Similarly, in one of its most recent Definitive Planning Phase (DPP) study for generator interconnection, MISO identified the need for nearly $2.5B[30] worth of

[28] Includes only GI projects that are currently active in the queue or have an executed interconnection agreement.
[29] Source: DISIS-2017-001 published on April 28, 2021
[30] Source: DPP-2019 Phase 1 published on July 16, 2020.

transmission network upgrades to interconnect 9.2 GW of generation in MISO South.

The allocation of all network upgrade costs to the developers suggests that the projects do not provide any economic benefits to consumers. As demonstrated in this study, however, some projects provide broader regional benefits.

Currently, MISO's tariff requires majority[31] of the costs for generator interconnection network upgrade costs to be paid by the interconnection customers while the benefits of these network upgrades could potentially accrue to other stakeholders. In particular, the benefits to customers could potentially exceed the costs allocated to customers.

With the level of renewable penetration anticipated over the next several years, MISO's and SPP's focus on value-based planning is ever critical. Early stages of the planning were one of the key drivers in establishing the portfolio of Multi-Value Projects (MVPs) in MISO and priority projects in SPP that have been instrumental in integrating over 20 GW[32] of new renewables across both of their footprints. Since the portfolio of MISO's MVP and SPP's priority projects were proposed, generator interconnection queue in both markets have been flooded with requests for interconnecting proposed renewable resources. As the trend towards incorporating renewable resources to the generation mix continues at almost an exponential rate, it is imperative that the transmission grid is robust enough to help facilitate such penetration levels.

The recently completed DPP studies however indicate that there are certain areas in the transmission system that acts as a bottleneck in enabling renewable buildouts. This is evident by the amount of GI projects that withdraw after phase 1 of the DPP studies due to the high network upgrade costs that are identified. Exhibit 11 below for example, shows the change in network upgrade costs and the number of interconnection requests in the 2018 MISO South DPP cycle. In the 2018 DPP phase 1 study, MISO indicated a total network upgrade costs over $2B[33] to interconnect the projects in the queue. That estimated total network upgrade costs dropped to $230M[34] when MISO completed phase 2 of the 2018 DPP study for MISO South (nearly 75% of the projects that entered the 2018 MISO South DPP cycle withdrew).

SPP is experiencing a similar trend where huge network upgrade costs in the initial phases of the analyses leads to the withdrawal of several GI projects. For example, the DISIS-2017-001 cluster in SPP initially identified nearly $8.5B worth of upgrades to interconnect nearly 14.5 GW of generation while phase 2 of the cluster saw the withdrawal of 4 GW of GI projects from the queue. The withdrawal cut the cost of the interconnection upgrades by half and now stands at $4.7B.

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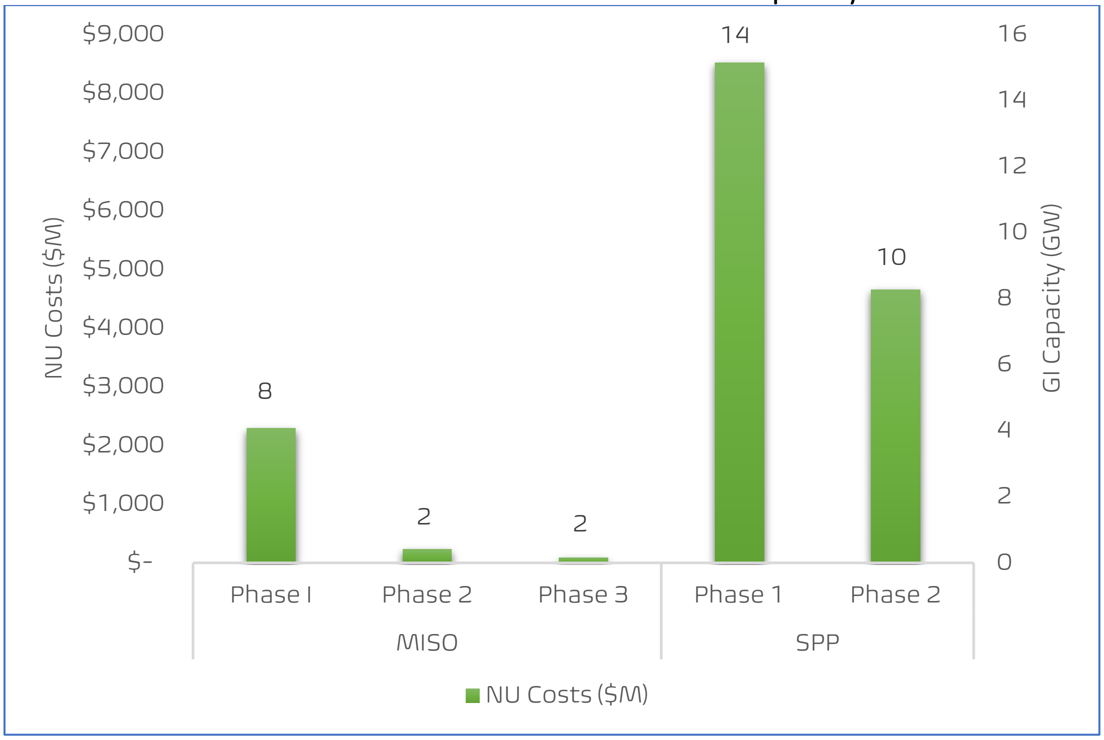
[31] For transmission network upgrades 345 kV and above, MISO allocates 90% of the costs to the interconnection customers while the remaining 10% is assigned to load on a postage stamp basis.
[32] Source: SPP – SPP Priority Projects Phase II Report dated February 1, 2010, | MISO - https://www.misoenergy.org/planning/planning/multi-value-projects-mvps/#t=10&p=0&s=&sd=
[33] Refer to the "Final MISO DPP 2018 April South Area Study Phase I Report"
[34] Refer to the "Final MISO DPP 2018 April South Area Study Phase II Report"

Exhibit 7: MISO's 2018 DPP South NU and Capacity Trends



Source: MISO 2018 DPP South Report and SPP DISIS 2017-001 Report

4. STUDY DESIGN

The Study Design section is structured to provide a brief description of the steps taken in conducting the study. The subsections present details of the assumptions, the determination of network upgrades, and matching of GI projects associated with the shortlisted network upgrades in the modeling database. Ultimately, the assumptions and inputs into the model are evaluated and reported in the form of Adjusted Production Cost (APC) savings that is used as a metric to determine the consumer benefits of the shortlisted network upgrades.

ICF used ABB's PROMOD IV® simulation software to capture the benefits of transmission network upgrades associated with generator interconnection projects. PROMOD is a fundamental electric market simulation solution that incorporates extensive details in generating unit operating characteristics, transmission grid topology, and constraints, and market system operations to support economic transmission planning.

Benefits associated with the shortlisted network upgrades were evaluated by capturing the change in APC across the entire footprint of MISO and SPP individually. To determine the change in APC, ICF modeled a "Base Case" without the proposed transmission network upgrade and a "Change Case" that included the network upgrade. With everything else the same between the two cases, the change in APC can be attributed to the inclusion of the network upgrade.

4.1. Adjusted Production Cost (APC) Methodology

APC is one of the key metrics used by both MISO and SPP in its evaluation of economic benefits of potential transmission upgrades. The APC is the total of production costs of a generation fleet including fuel, operations and maintenance, startup costs, and emissions that is adjusted by the transaction cost. A company's transaction cost includes purchases and/or sales within an ISO's footprint (within pool transaction cost) and purchases and/or sales between a company within an ISO and a company outside of the same ISO (inter-pool transaction cost). The APC is calculated on an hourly basis for each company within the ISO. For example, MISO calculates the APC as:

> **Adjusted Production Cost**
> APC is the total of production costs of a generation fleet within a region adjusted by transaction costs. The production cost includes fuel costs, operations and maintenance costs, startup costs, and cost of emission allowances. The transaction cost includes purchases and/or sales within the region and between the region and other regions.

Hourly Company APC = Hourly Production Cost + Hourly Fixed Transaction Cost + Hourly Emergency Energy Cost + Hourly Inter-pool Transaction Cost + Hourly Within Pool Transaction Cost[35]

[35] Source: MISO Adjusted Production Cost Calculation White Paper dated February 1, 2019

Exhibit 8: APC Metric Components

APC Component	Description
Hourly Production Cost	The hourly production cost represents the final cost of operating a company's thermal fleet. The calculation includes fuel costs, startup costs, emission costs, and variable O&M costs.
Hourly Fixed Transaction Cost	The hourly fixed transaction cost represents the production costs of generators without fuel (renewables).
Hourly Emergency Energy Cost	The hourly emergency energy cost represents the cost of injecting power at an existing generator site in addition to the modeled generation capacity to reliably serve load. The emergency energy injection and its pricing are a proxy for deferred reliability transmission investment, generation investment, scarcity pricing, or the loss of load. Emergency energy is priced at $1,000/MWh
Hourly Inter-pool Transaction Cost	The hourly inter-pool transaction cost represents a company's purchases and sales with other companies outside of the ISO.
Hourly Within Pool Transaction Cost	The hourly within pool transaction cost represents the cost of a company's purchases and sales with other companies within the ISO.

4.2. Calculation of Net Present Value (NPV)

The PROMOD analysis of the three model run years results in nominal APC benefits or costs. Several factors go into the calculation to determine the benefit-to-cost (B/C) ratio such as the APC benefits, cost of the network upgrade, annual revenue requirements (ARR), after-tax weighted average cost of capital (WACC), and inflation rate. These factors are computed over a 20-year period for MISO and a 40-year period for SPP from the start of the assumed in-service date of the network upgrades.

4.3. Methodology and Modeling Assumptions

The United States' entire Eastern Interconnect power system is represented in the underlying PROMOD database and reflects a nodal network topology that constitutes transmission lines 69 kV and higher. In addition, the database is updated to reflect generation capacity expected in the three model-run years[36] to reflect MISO's MTEP21 Market Congestion Planning Study (MCPS) process. The network topology and the generation capacities, along with demand, gas prices, coal prices, federal tax credits, renewable mandates, transmission constraints, and hourly profiles, are fed into the PROMOD database. The database is simulated to reflect a security constrained economic dispatch (SCED) of generation over an 8760-hour period based on the inputs

[36] For the analysis, ICF chose to perform the analysis for three model-run years to reflect MISO's MCPS process. ICF performed the analysis for 2025 (5-year out), 2030 (10-year out), and 2035 (15-year out).

provided to capture the impact of transmission constraints on congestion and price formation.

ICF incorporated MISO's Future 1 assumptions for supply, demand, and capacity expansion in the underlying PROMOD database. The Future 1 factors in utility's energy announcements and plans,[37] state mandates, goals, or preferences[38], and an associated carbon emissions reduction of 40% relative to 2005 levels in MISO. In addition, age-based retirements of coal generation are set to 46 years while combined-cycle natural gas plants are set to 50 years. In addition to Future 1, MISO has established two additional futures to capture the different ranges of economic, political, and technological changes over a 20-year period. Future II and III scenarios include significantly higher renewable penetration. As such, ICF's reliance on Future I for assessment of benefits of transmission upgrades should be considered a conservative assumption. All else equal, higher renewable capacity associates with each network upgrade will yield higher system benefits. The exhibit below provides details of all three of the futures.

Exhibit 9: MISO Futures Assumptions Summary

Variables / Futures	Future I	Future II	Future III
Percent of Goals Met	85% goals met 100% IRPs met	100% goals met 100% IRPs met	100% goals met 100% IRPs met
Carbon Emissions Reduction* (2005 baseline)	40% (currently at 22%)**	60%	80%
Retirements-Coal Retirements-Natural Gas- CC Retirements-Natural Gas-Other	46 years 50 years 46 years	36 years 45 years 36 years	30 years 35 years 30 years
Wind and Solar Penetration	No minimum	No minimum	50%
EV Adoption & Charging Technology	Low-Base EV growth Uncontrolled charging	Base-High EV growth Uncontrolled 2020-2035 & V2G 2035 and beyond	Extra-High EV growth Uncontrolled 2020-2030 & V2G 2030 and beyond
Electrification (includes EVs and gas to electric appliances / heating / cooling)	None	19% of technical potential realized representing a 16% energy growth	40% of technical potential realized representing a 34% energy growth
Demand & Energy Growth^	0.59% 0.63%	1.09% 1.23%	1.94% 1.91%
DER Technical Potential by 2040 (GW)^^	DR: 5.2 EE: 13.3 DG: 14.7	DR: 5.9 EE: 14.5 DG: 14.7	DR: 5.9 EE: 14.5 DG: 21.8
Natural Gas Prices	Base starting price determined by GPCM; Future-specific price input to PROMOD	Base starting price determined by GPCM; Future-specific price input to PROMOD	Base starting price determined by GPCM; Future-specific price input to PROMOD

Source: MTEP21 Futures White Paper dated April 27, 2020

[37] Future 1 incorporates 100% of utility integrated resource plan announcements | Source: MISO Futures Report
[38] Unlegislated goals and preferences are applied at 85% of the announcements to hedge for uncertainty | Source: MISO Futures Report

For the SPP market, the database was updated to reflect generation capacities expected during the study period. Consistent with SPP's ITP process, ICF modeled three run years – 2023 (2-year out), 2026 (5-year out), and 2031 (10-year out). The network topology and the generation capacities, along with demand, gas prices, coal prices, federal tax credits, renewable mandates, transmission constraints, and hourly profiles, are fed into the PROMOD database. The database is simulated to reflect a security constrained economic dispatch (SCED) of generation over an 8760-hour period in each year to capture the impact of transmission constraints on congestion and price formation.

Similar to MISO, ICF incorporated the most conservative scenario- Future 1 assumptions for supply, demand, and capacity expansion. Future 1 reflects the continuation of current industry trends and environmental regulation. Solar and wind additions are assumed to exceed current renewable portfolio standards (RPS) due to economics, public appeal, and the anticipation of potential policy changes. In addition, age-based retirements of coal generation are set to 56 years while gas-fired and oil generators are set to 50 years. Battery energy storage resources are included relative to the approved solar amounts [39]. For Future 1, the level of energy storage is 20% of the projected solar capacity. Like MISO, SPP has also established an additional, Future 2 which reflects a scenario driven by the adoption of emerging technologies such as electric vehicles, distributed generation, demand response, and energy efficiency. Age-based retirements of thermal generators are accelerated in Future 2, and it also assumes a more aggressive buildout of solar, wind, and energy storage resources when compared with Future 1.[40] Exhibit 14 below provides an overview of the assumptions that is reflected in SPP's Futures.

[39] Source: 2021 ITP Assessment Scope dated August 5, 2020.
[40] Source: 2021 ITP Assessment Scope dated August 5, 2020.

Exhibit 10: SPP Futures Assumptions Summary[41]

KEY ASSUMPTIONS	YEAR 2	REFERENCE CASE YEAR 5 YEAR 10	EMERGING TECHNOLOGIES YEAR 5 YEAR 10
Peak Demand Growth Rates	As submitted in load forecast	As submitted in load forecast	As submitted in load forecast
Energy Demand Growth Rates	As submitted in load forecast	As submitted in load forecast	Increase due to electric vehicle growth
Natural Gas Prices	Current industry forecast	Current industry forecast	Current industry forecast
Coal Prices	Current industry forecast	Current industry forecast	Current industry forecast
Emissions Prices	Current industry forecast	Current industry forecast	Current industry forecast
Fossil Fuel Retirements	Current forecast	Coal age-based 56+, Gas/Oil age-based 50+, subject to generator owner review	Coal age-based 52+, Gas/Oil age-based 48+, subject to GO review and ESWG approval
Environmental Regulations	Current regulations	Current regulations	Current regulations
Demand Response[1]	As submitted in load forecast	As submitted in load forecast	As submitted in load forecast
Distributed Generation (Solar)	As submitted in load forecast	As submitted in load forecast	+300MW +500MW
Energy Efficiency	As submitted in load forecast	As submitted in load forecast	As submitted in load forecast
Storage	None	20% of projected solar	35% of projected solar

Source: 2021 ITP Assessment Scope dated August 5, 2020.

4.4. Determination of Network Upgrades

ICF reviewed MISO's Definitive Planning Phase (DPP) reports published for all cycles from 2016 onwards and SPP's Definitive Interconnection System Impact Study (DISIS) reports published for all clusters from 2014[42] onwards to come up with an initial list of network upgrades that could be evaluated.

[41] Future 1 – Reference Case | Future II – Emerging Technologies
[42] As SPP is currently evaluating GI projects that have entered the queue in 2017, ICF began with DISIS reports for the 2014 cluster as opposed to MISO's DPP reports that were reviewed from 2016 onwards.

The exhibit below presents a set of criteria ICF applied to shortlist the set of network upgrades that would eventually be analyzed.

Exhibit 11: Determination of Network Upgrades[43]

Criteria	Description
Sub-Region	Representations from throughout MISO's and SPP's footprints were considered for the analysis. For MISO, the focus was around the sub-regions (West, Central, East, and South) and for SPP, the focus was around the SPP North and SPP South.
Voltage Threshold	Proposed transmission network upgrades 230 kV and above for MISO and 345 kV and above for SPP were considered for the analysis[44]
Implied Cost Threshold ($/kW) [45]	Proposed transmission network upgrades with a $100/kW or below were considered for the analysis
Repetitiveness	Transmission network upgrades that were identified in multiple DPP cycles (MISO) or DISIS studies (SPP) were given preference

Six network upgrades were subsequently selected from each ISO for the study. The shortlisted projects for both markets are shown in exhibits 16 and 17 with exhibit 18 showing the geographic location of each project in both markets.

Exhibit 12: Shortlisted MISO Network Upgrades

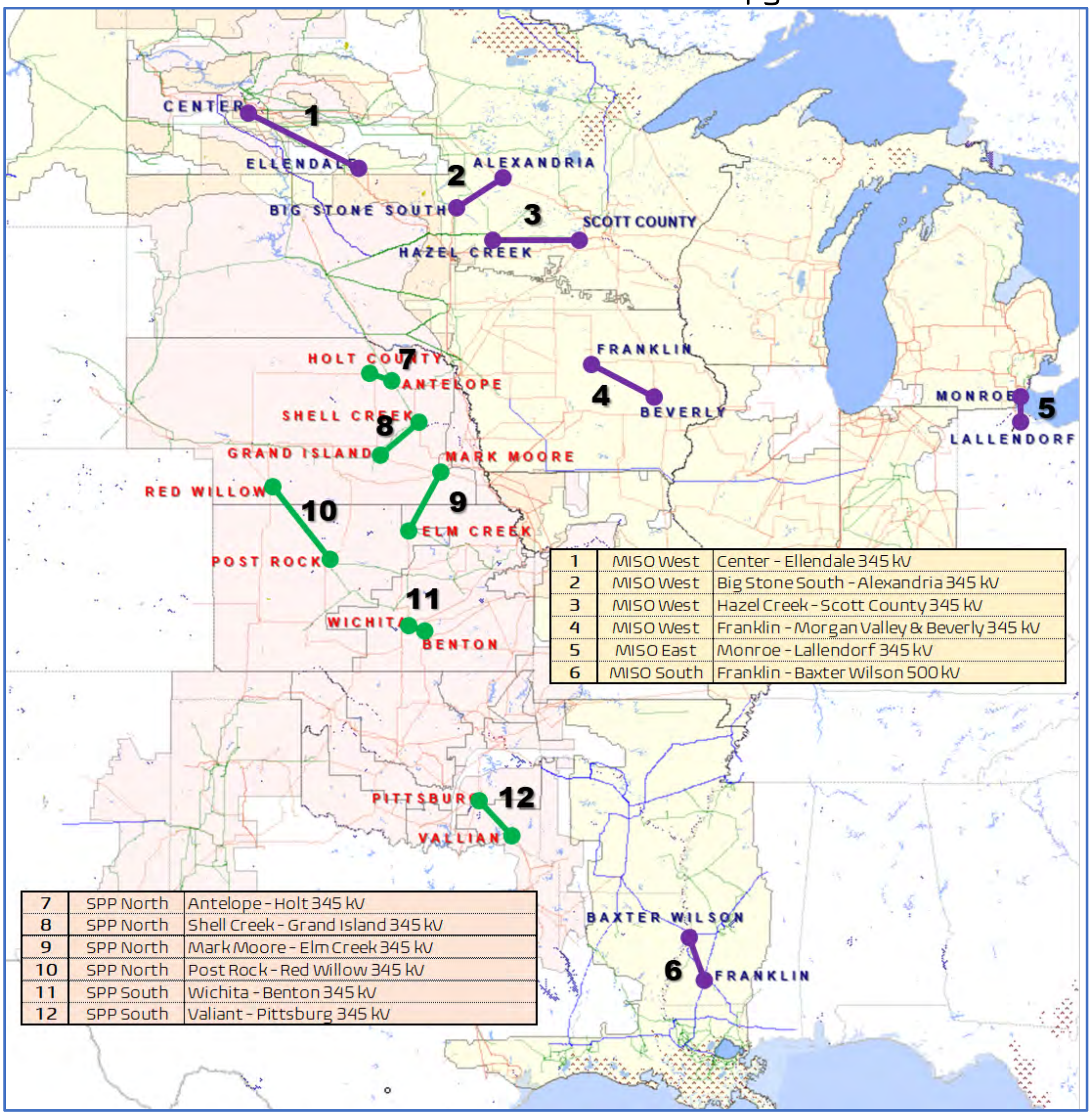
Network Upgrade	Sub-Region	Voltage (kV)	Implied Cost Threshold ($/kW)	Repetitiveness [46]
Franklin – Morgan Valley & Beverly	West	345	$94.83	2
Big Stone South – Alexandria	West	345	$45.05	3
Center – Ellendale [47]	West	345	$332.31	2
Hazel Creek – Scott County	West	345	$47.70	3
Monroe – Lallendorf	East	345	$7.21	2
Franklin – Baxter Wilson	South	500	$58.35	1

[43] Due to the differences in modeling methodology and the analytical approach between RTOs, inter-regional network upgrades were not considered as part of the study.
[44] The 230 kV and 345 kV voltage thresholds for MISO and SPP respectively is consistent with how the two ISOs determine transmission projects that would be regionally cost allocated through their economic planning studies.
[45] The set of generators allocated the cost of a network upgrade is referred to as the GI capacity associated with that network upgrade. The implied cost is calculated as the total GI capacity associated with the network upgrade divided by cost of the network upgrade.
[46] The repetitiveness indicates the number of DPP/DISIS cycles the network upgrades were proposed.
[47] Even though Center – Ellendale 345 kV network upgrade did not meet the $100/kW criteria, the upgrade was evaluated to determine complementary nature of this upgrade to Big Stone South – Alexandria 345 kV line which is discussed in the Section 5

Exhibit 13: Shortlisted SPP Network Upgrades

Network Upgrade	Sub-Region	Voltage (kV)	Implied Cost Threshold ($/kW)	Repetitiveness
Antelope – Holt	SPP North	345	$44.90	3
Shell Creek – Grand Island	SPP North	345	$87.90	1
Mark Moore – Elm Creek	SPP North	345	$108.52	1
Post Rock – Red Willow	SPP North	345	$90.50	2
Wichita – Benton (2nd Line)	SPP South	345	$5.30	2
Valiant – Pittsburg (2nd Line)	SPP South	345	$65.70	2

Exhibit 14: MISO and SPP Network Upgrades



4.5. Matching GI Projects Associated with Network Upgrades

Because the network upgrades are proposed to enable interconnection of specific generation resources, ICF examined firm and proposed builds in MISO's and SPP's Future I assumptions to determine if the GI projects associated with the shortlisted network upgrades or similarly placed GI projects were included in the model. Firm generation includes projects that are under construction or in advanced stages of development and are very likely to be placed in service. Proposed generation in the MISO Future 1 assumptions include Regional Resource Forecast (RRF) generation, and Integrated Resource Plan (IRP) generation. RRF generation are various resource types that are defined in and selected by MISO's capacity expansion tool, EGEAS, to achieve each of the Futures scenarios. The RRF units used in MISO comprise wind, solar, hybrid resources, 4-hour storage, distributed energy resources (DERs), natural gas resources, and combined cycle & carbon capture sequestration[48]. SPP also includes RRF generation identified through its capacity expansion analysis in its Future 1 assumptions.

For GI projects that were not originally included in the regions' Future I assumptions, ICF determined if similarly placed generators could act as a proxy for the GI builds. Similarly placed generators were determined based on a set of criteria as laid out below.

- **Location of builds.** For MISO, similarly placed generators were determined based on the Local Resource Zones (LRZ). For example, a similarly placed generator could function as a proxy of a GI project associated with a network upgrade if both the generators are intended to be in the same LRZ. With this approach, the overall LRZ level build and the MISO-wide build assumptions in Future I remained the same. For SPP, similarly placed generators were determined by subregion (SPP North and SPP South) while retaining the overall subregional level builds.
- **Impact on the network upgrade.** ICF relied on a distribution factor[49] (DFAX) criteria to determine if a similarly placed generator could function as a proxy for the GI projects. The impact of a similarly placed generator on the network upgrade from DFAX standpoint should tantamount to the DFAX of the GI project on the network upgrade.
- **Resource capacity.** The capacity of the similarly placed GI project should be in line with the GI project associated with the network upgrade.

Based on the above criteria, only a portion of the GI builds associated with the network upgrades were matched in the PROMOD databases of both RTOs. For MISO, the year 5 (2025) database had the least GI builds at 19% while year 10 (2030) and year 15 (2035) databases had just under 50% of the GI builds. The limitations were largely due to the lack of same or similarly placed generators within a specific LRZ and the DFAX methodology that was applied.

For SPP, ICF matched nearly 81% of the GI builds associated with shortlisted network upgrades in year 5 and nearly 92% of the GI builds in year 10. Exhibits 19 and 20 below presents the level of GI builds associated with the shortlisted network upgrades that were matched in the models for MISO and SPP, respectively.

[48] Source: MISO Futures Report dated April 2021

[49] Distribution factor is a measure of the proportion of the output of a generator that will flow on a specified transmission line.

Exhibit 15: Same or Similarly Placed Builds Associated with Network Upgrades in MISO

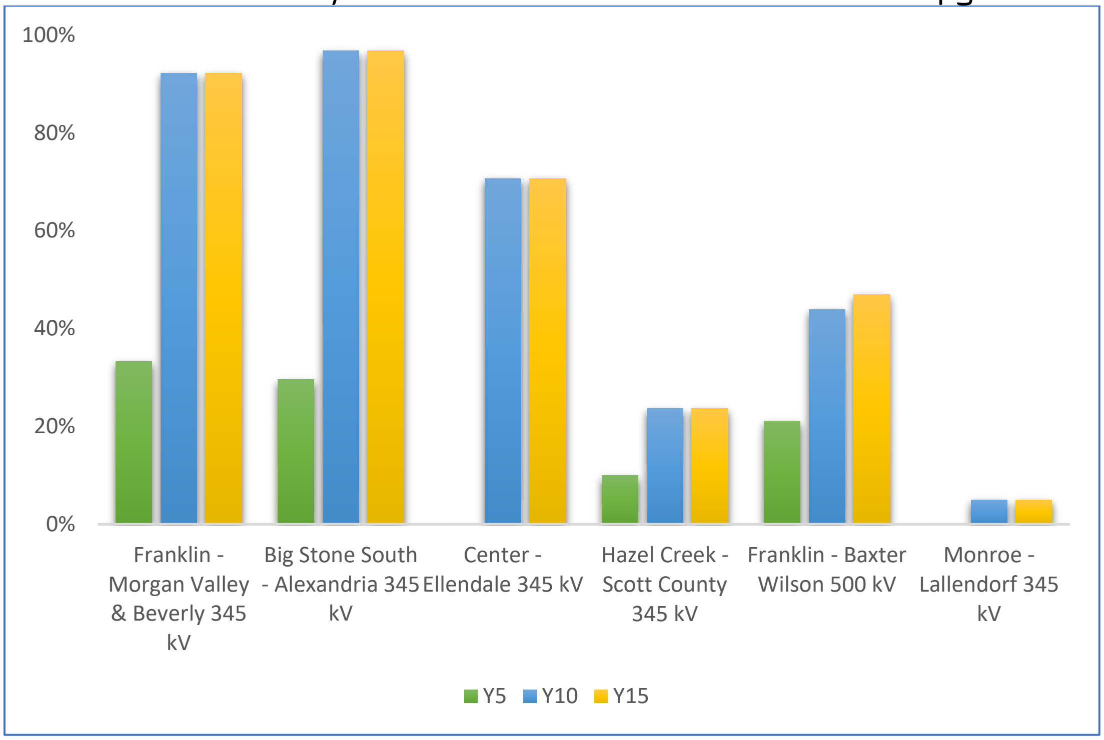


Exhibit 16: Same or Similarly Placed Builds Associated with Network Upgrades in SPP

5. RESULTS

A summary of the 12 network upgrades analyzed in this study is shown in Exhibit 26. The exhibit also summarizes the cost of the network upgrade, the benefits in the form of APC savings calculated from the PROMOD modeling, and the benefit-to-cost ratio. In addition, the table provides a percentage of generator interconnection (GI) builds associated with each of the network upgrades that are represented in MISO's and SPP's planning scenarios, which impacts the resulting benefits calculation.

Exhibit 17: Summary of Findings

Region	NU #	Network Upgrade	GI Capacity [50] Y2 / Y5 / Y10 / Y15[51]	Cost[52]	APC Savings (Benefits)[53]	B/C[54]
MISO West	1	Center – Ellendale 345 kV	- / 0% / 71% / 71%	$456.2M	$181.9M	0.40
MISO West	2	Big Stone South – Alexandria 345 kV	- / 30% / 97% / 97%	$221.4M	$335.8M	1.52
MISO West	3	Hazel Creek – Scott County 345 kV	- / 10% / 24% / 24%	$236.4M	$85.4M	0.36
MISO West	4	Franklin – Morgan Valley & Beverly 345 kV	- / 33% / 92% / 92%	$597.4M	-$4.8M	-
MISO East	5	Monroe – Lallendorf 345 kV Rebuild	- / 0% / 5% / 5%	$44.9M	$2.9M	0.06
MISO South	6	Franklin – Baxter Wilson 500 kV	- / 21% / 44% / 47%	$350.5M	$41.1M	0.12
SPP North	7	Antelope – Holt 345 kV	0% / 82% / 90% / -	$276.6M	$142.8M	0.52
SPP North	8	Shell Creek – Grand Island 345 kV	0% / 100% / 100% / -	$208.7M	$61.7M	0.30
SPP North	9	Mark Moore – Elm Creek 345 kV	0% / 89% / 96% / -	$259.3M	$10.4M	0.04
SPP North	10	Post Rock – Red Willow 345 kV	0% / 72% / 100% / -	$345.8M	-$8.9M	-
SPP South	11	Wichita – Benton 345 kV 2nd Line	0% / 90% / 97% / -	$32.1M	$59.3M	1.85
SPP South	12	Valiant – Pittsburg 345 kV 2nd Line	0% / 90% / 97% / -	$282.9M	$86.2M	0.30

Ten of the 12 network upgrades assessed in this study provided positive APC benefits.

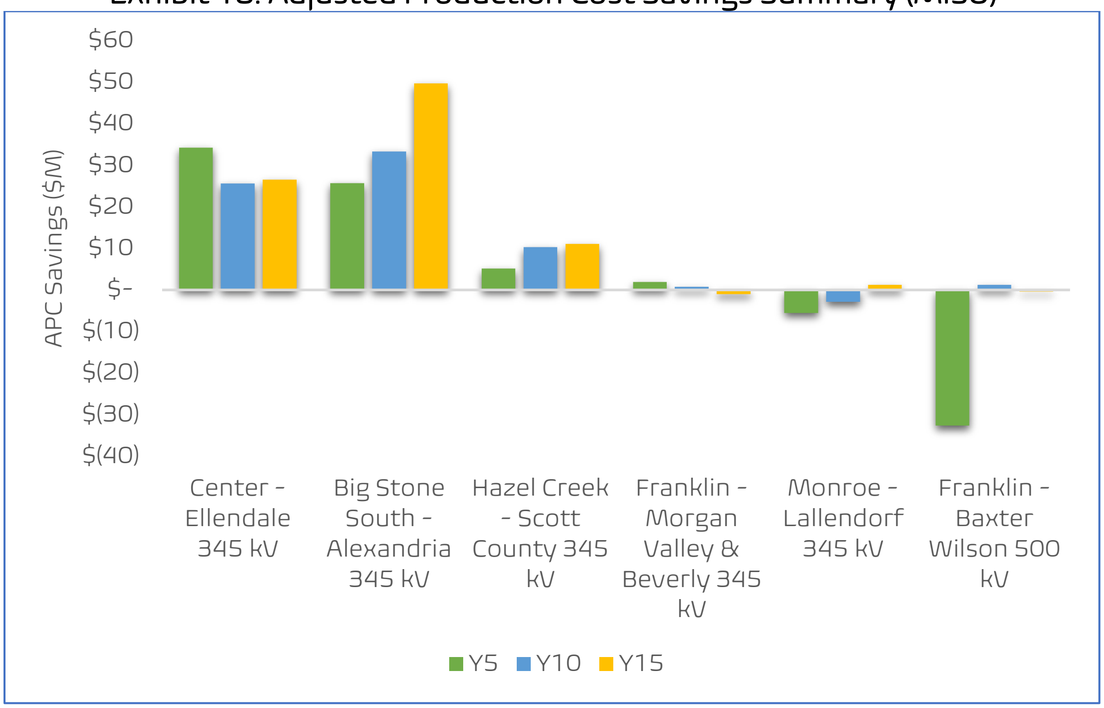
[50] Percent capacity of the total GI projects associated with each of the network upgrades that is represented in the RTO Planning Scenarios.
[51] MISO's model run years: Y5 (2025), Y10 (2030), Y15 (2035) | SPP's model run years: Y2 (2023), Y5 (2026), Y10 (2031).
[52] Cost represents the 20-year (for MISO) or 40-year (for SPP) total costs of each network upgrade.
[53] Benefits represent adjusted production cost (APC) savings attributed to the new transmission project. For MISO network upgrades, the APC savings represent the 20-year NPV while the APC savings represent the 40-year NPV for SPP network upgrades.
[54] Calculated as benefits divided by cost for each transmission project. A ratio greater than 0.1 in MISO and 0 in SPP indicates that benefits to the consumer exceeds cost allocated to them.

In general, of the network upgrades modeled, those with a higher percentage of interconnection projects represented in the future scenario resulted in higher APC savings. Six of the nine network upgrades with 70% or greater of the same or similarly placed GI capacity represented in the RTO planning models resulted in significant benefits to the system, ranging from $59M to $335M.

Specifically, Center – Ellendale (NU #1), Big Stone South – Alexandria (NU #2), Antelope – Holt (NU #7), Shell Creek - Grand Island (NU # 8), Wichita - Benton (NU #11), and Valiant - Pittsburg (NU #12) provided high APC savings due to significant share of GI capacity in the planning models. Other upgrades with a lower percentage match, such as Monroe – Lallendorf (NU #5) and Franklin – Baxter (NU #6) with only 5% and 47% of the associated GI capacity respectively, showed diminutive benefits. Higher GI capacity representation in the planning models was not the only driver of APC savings.

Consistent with the MISO and SPP planning processes, APC savings and costs were assessed over 20-year and 40-year study periods, respectively. The exhibit below shows the APC savings for the network upgrades in MISO for the three model run years- Year 5 (2025), Year 10 (2030) and Year 15 (2035). The APC values from the PROMOD model run years[55] were interpolated and extrapolated to determine the 20-year present value of the benefits.

Exhibit 18: Adjusted Production Cost Savings Summary (MISO)

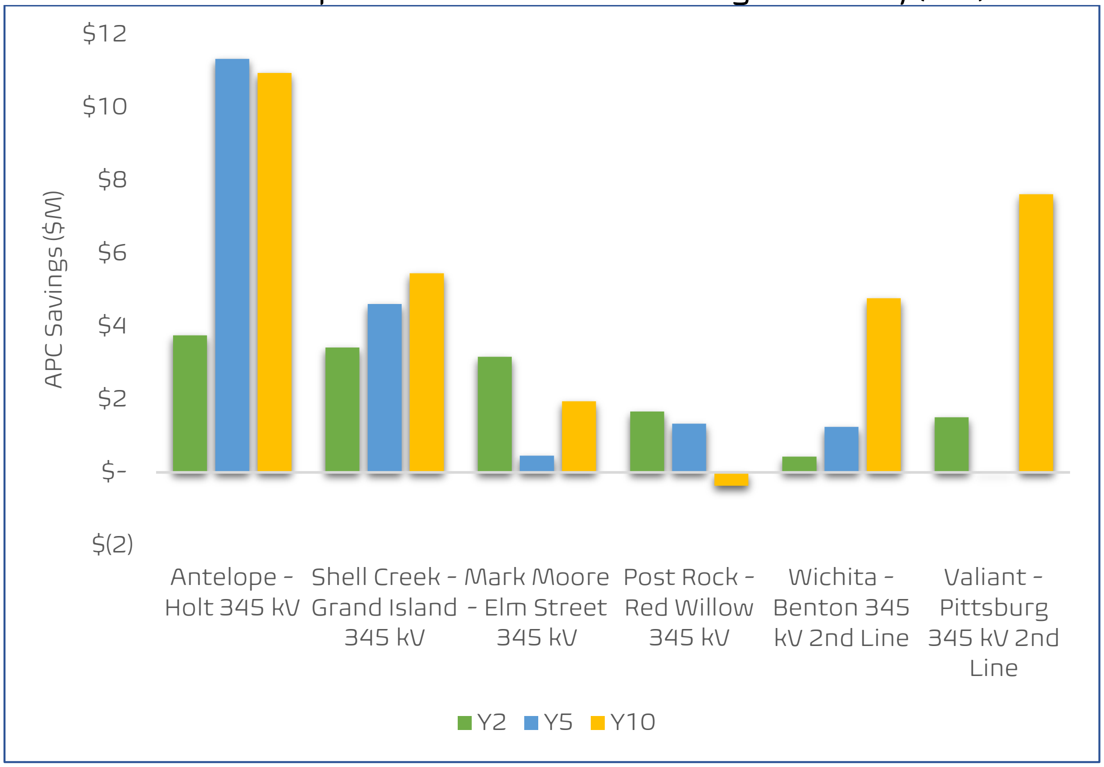


The APC savings for the three run years modeled in SPP, Year 2 (2023), Year 5 (2026), Year 10 (2031), are shown in the exhibit below. The APC values from the PROMOD model run years were interpolated and extrapolated to determine the present value of

[55] MISO's model run years: Y5 (2025), Y10 (2030), Y15 (2035) | SPP's model run years: Y2 (2023), Y5 (2026), Y10 (2031).

the benefits for years 1-15. ICF applied an inflation rate of 2%[56] to capture the benefits for years 16-40. The 40-year value of costs are based on the revenue requirement over the first 40 years of the project. The study uses approaches that are consistent with MISO's and SPP's planning processes.

Exhibit 19: Adjusted Production Cost Savings Summary (SPP)



Several factors affected the level of observed APC savings. These include:

- **Upgrades in locations with frequent and persistent congestion provided benefits even with relatively lower percentage of associated generation interconnection projects.** Regardless of the amount of associated generation represented in the planning model, a network upgrade in an area with frequent and persistent congestion could provide significant benefits to the system through congestion relief.

- **Increase in congestion on transmission lines in the vicinity of the upgrade after implementation of the upgrade.** Implementing the network upgrade could result in congestion moving to other facilities in the vicinity of the network upgrade. For example, congestion could move to a line downstream of the network upgrade and reduce the impact of the project. Because the scope was narrowly focused on single network upgrades, only one upgrade was selected and implemented in each case. Other network upgrades deemed required in the MISO and SPP

[56] Based on SPP's approach in calculating 40-year NPV benefits.

generation interconnection studies to enable the full capacity of each cluster of generation interconnection projects were not implemented. Including these upgrades could result in additional benefits.

5.1. Benefit-to-Cost Ratios

The exhibits below provide details around the benefit-to-cost (B/C) ratios for each of the ten network upgrades with positive APC savings. Exhibit 29 shows the results for the projects in MISO and Exhibit 30 shows the results for SPP. Each exhibit shows the present value of the benefits and costs, as well as the B/C ratio. For example, the present value of benefits of the Big Stone South – Alexandria network upgrade is approximately $335.8M, compared with a present value of cost of approximately $221.4M. The resulting B/C ratio is 1.52.

The B/C ratio for the ten projects shown ranged from a low of 0.04 for the Mark Moore – Elm Creek 345 kV network upgrade in SPP to as high as 1.85 for the Wichita – Benton 345 kV network upgrade in SPP. Seven network upgrades have B/C ratios greater than or equal to 0.30. The results show that many projects provide significant regional economic benefits, and some even more than the costs. For example, the Big Stone – South Alexandria 345 kV in MISO and Wichita – Benton 345 kV in SPP have the potential to provide benefits that far exceed the cost to the system.

Exhibit 22: 20-Year NPV ($M) and B/C Ratio of Network Upgrades (MISO)

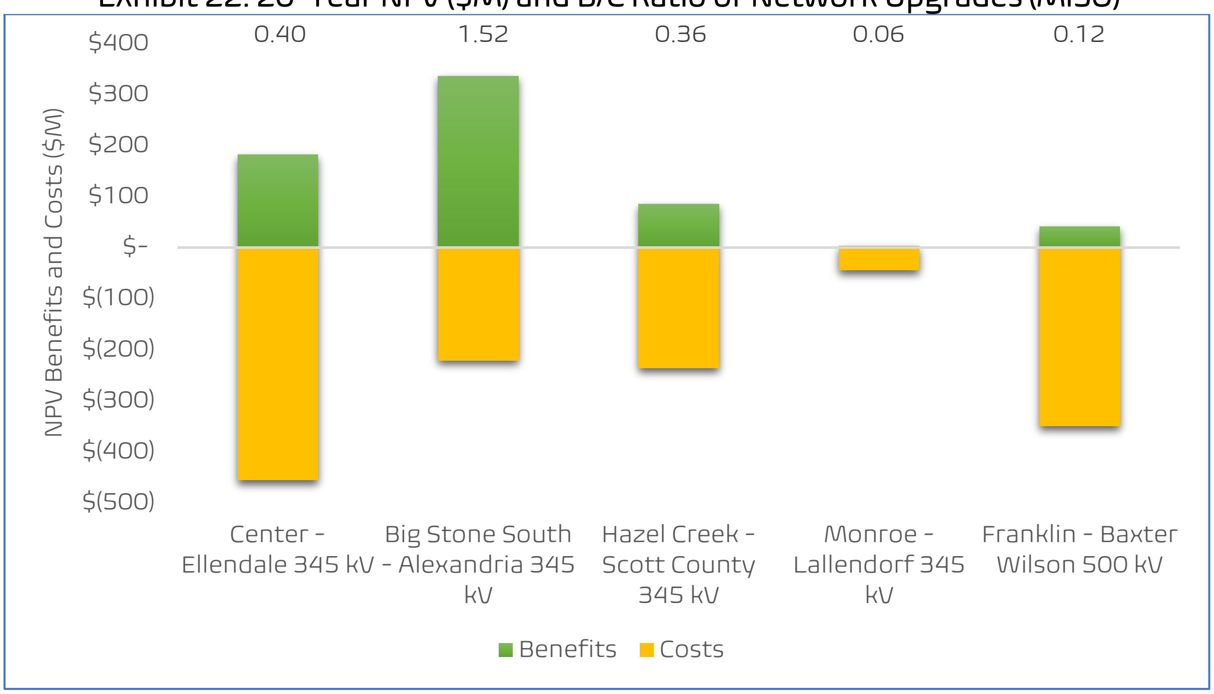
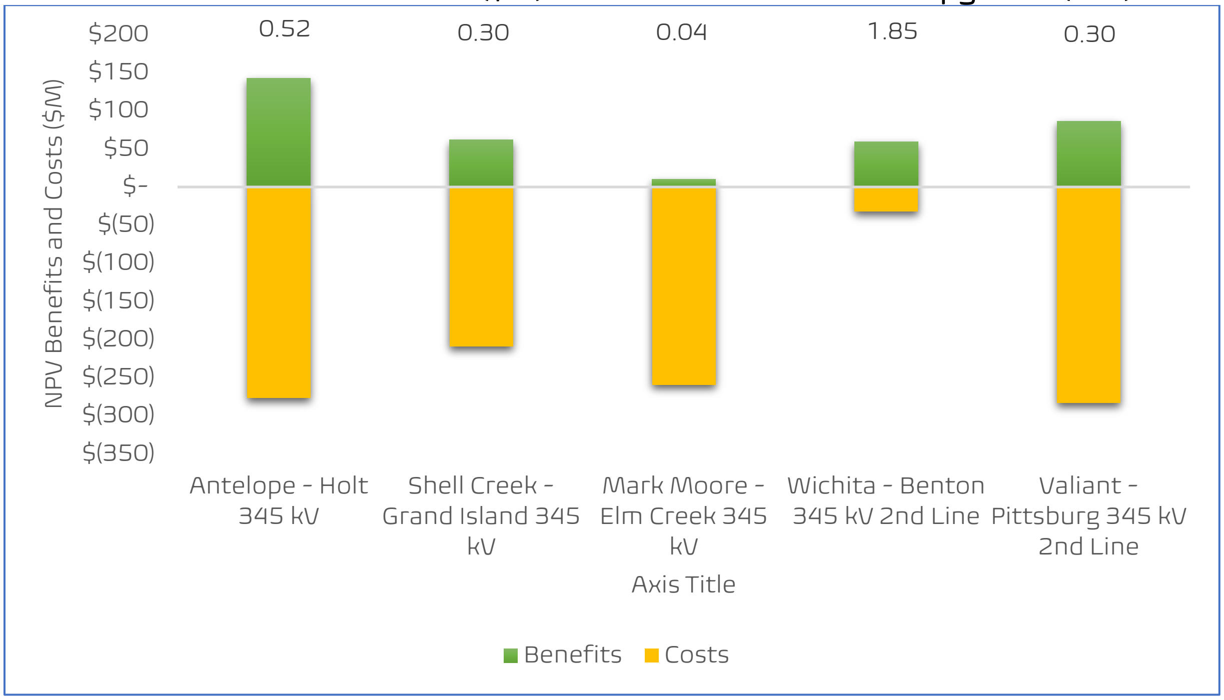
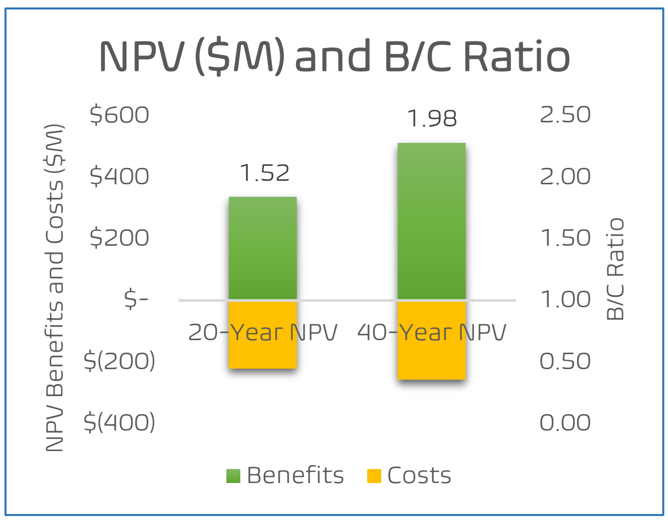


Exhibit 23: 2040-Year NPV ($M) and B/C Ratio of Network Upgrades (SPP)



The 20-year NPV calculation is based on MISO's current Market Congestion Planning Study (MCPS) process. However, understanding that transmission lines are usually far greater than 20-year assets, ICF calculated a 40-year NPV of the benefits and the costs by extrapolating the results from the models. Applying this method to Big Stone South – Alexandria 345 kV network upgrade, for example, yielded a B/C ratio of 1.98 (as compared with the B/C ratio of 1.52 across a 20-year period). This demonstrates that over its service life, the network upgrade could potentially provide even more benefits to consumers than what the 20-year B/C ratio indicates.



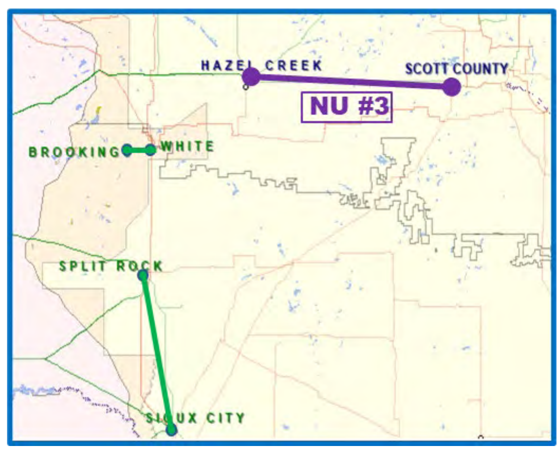
The drivers of benefits and B/C ration for each of the network upgrades is described in more detail below.

MISO Network Upgrades

- **Center – Ellendale 345 kV (NU #1),** located in North Dakota, helps deliver power from the wind-rich region to load centers in MISO West. Up to 71% of the GI projects associated with NU #1 were represented in the planning model, resulting in significant benefits from the network upgrade. Over the 20-year study period NU #1 provided $181.9M in APC savings, compared to a cost of $456.2M, and resulting in a B/C ratio of 0.40. The network upgrade eases congestion on the 230 kV line from West Oakes to Ellendale. However, inclusion of this upgrade increases congestion on the downstream Big Stone South to Browns Valley and White to Brookings County transmission lines.

- **Big Stone South – Alexandria 345 kV (NU #2)** provides the highest benefits of the projects in MISO. Up to approximately 97% of the GI projects associated with NU #2 were represented in the planning model. The result was $335.8M in APC savings relative to a cost of $221.4M, and a B/C ratio of 1.52. NU #2 also relieves congestion on 230 kV line from Big Stone South to Browns Valley and significantly reduces wind curtailment. Much like NU#1, increased flows enabled by NU#2 also increases congestion on West Oakes to Ellendale, likely limiting the overall benefits. Inclusion of associated network upgrades such as the West Oakes – Ellendale 345 kV line upstream of Big Stone South – Alexandria could increase the value proposition of the network upgrade. The constraints affected by NU #1 and NU #2 suggest some synergies between the two network upgrades and a portfolio comprising of the two projects may potentially result in significantly higher benefits. Additional analysis will be required to determine the potential for the projects to be developed as a portfolio.

- **Hazel Creek – Scott County 345 kV (NU #3)** is located between wind-rich areas in MISO West and load centers in MISO Central. Unlike NU #1 and NU #2, NU #3 had only 24% of the associated GI projects represented in the planning model. Despite that, NU #3 provided significant benefits to the system – approximately $85M in APC savings and a B/C ratio of 0.36. The reason for the relatively high APC savings is the fact that NU #3 is located in an area with frequent and persistent congestion. It helps reduce congestion on lines southwest of Hazel Creek, such as White – Brookings County 115 kV and Aurora – Flandreau 115 kV. The network upgrade is also a critical path that transfers power into the city of Minneapolis.



- **Franklin – Morgan Valley & Beverly 345 kV (NU #4)** was the only project with a net cost in MISO. This was despite the high percentage (92%) of associated GI projects that were represented in the planning model. The primary driver for the negative savings attributed to this upgrade was increased congestion on the Tiffin – Hills 345 kV line. It is likely that additional network upgrades associated with GI projects in the DPP studies, which also highlighted the need for NU#4, may alleviate these chokepoints and potentially yield higher benefits. For example, MISO identified the need for new Webster – Franklin 345 kV line and Beverly – Sub92 345 kV lines in the same DPP study cycles as Franklin-Morgan Valley & Beverly. Additional analysis will be required to determine the potential for the projects to be developed as a portfolio.

- **Monroe – Lallendorf 345 kV (NU #5)** had the lowest percentage (5%) of associated GI capacity in the planning model and therefore had a very low APC savings of approximately $2.9M.

- **Franklin – Baxter Wilson 500 kV (NU #6)** network upgrade, located in Mississippi (MISO South) resulted in relatively low benefits compared to some of the MISO West network upgrades mentioned earlier. However, comparing the results from the model run years indicate that the benefits are somewhat suppressed due to the lack of higher levels of associated GI projects in the models. The APC of the network upgrade for year 5 resulted in incurred costs of over $30M. However, increase in associated GI builds between year 5 and year 10 resulted in APC savings of over a $1M (a change of nearly $34M). By year 10, only 47% of the GI capacity associated with this network upgrade was represented in the planning models. Inclusion of higher renewable builds could potentially yield significant benefits.

SPP Network Upgrades

- Located in Nebraska, the **Antelope – Holt 345 kV (NU #7)** network upgrade helps address congestion on transmission elements that serve the Lincoln and Omaha load centers and further east and southeast. Over the 40-year study period NU #7 provided $142.8M in APC savings at a B/C ratio of 0.52. In addition to high percentage of GI capacity match, this upgrade also eases pre-existing constraints on the Gentleman interface which leads to reduction in curtailment of wind energy that can be transferred from Nebraska and the Dakotas into the load centers in the east and south.

- Despite $61.7M in savings, the B/C ratio of **Shell Creek – Grand Island (NU #8)** was low due to higher upgrade cost. Much like NU#4, savings attributed to NU#8 were restricted due to increase in congestion on the Sweetwater – Grand Island 345 kV line. SPP identified the need for a 2nd Hoskins – Shell Creek 345 kV line that was not factored into the analysis. This is another example where a portfolio assessment may yield higher savings in addition to primary goal of reliably interconnecting large amounts of renewables. However, additional analysis will be required to determine the potential for the projects to be developed as a portfolio.

- **Mark Moore – Elm Creek 345 kV (NU #9)** network upgrade had the least B/C ratio of all the network upgrades that were evaluated. The inclusion of this network upgrade resulted in increased congestion on downstream elements such as the Columbus 230/115 kV transformer that limited the value proposition of this upgrade. The mitigation for the constraint however is the Shell Creek – Grand Island 345 kV line that was evaluated on a standalone basis. Similar to the potential synergies between Big Stone South – Alexandria 345 kV and Center – Ellendale 345 kV network upgrades in MISO, this region in Nebraska could benefit from a holistic solution that considers NUs #7, 8, and 9.

- Located in the southern portion of Nebraska, **Post Rock – Red Willow (NU #10)** was the only project with a net cost in SPP. This was despite the high percentage of associated GI projects that were represented in the planning model. The upgrade led to significant increase in congestion on the upstream Gentleman – Red Willow 345 kV line which yielded negative savings for this upgrade. In the same DISIS study cluster, SPP identified keystone – Red Willow 345 kV as a mitigation for several constraints including Gentleman – Red Willow 345 kV line.

- The **Wichita – Benton 345 kV (NU# 11)** network upgrade relieves congestion on lines such as the existing Wichita – Benton 345 kV transmission line and Wichita 345/138 kV transformer. In addition to that, the upgrade has significant GI capacity associated with it which leads to B/C ratio of 1.85, the highest for SPP and all twelve projects across both markets. The high B/C is in part driven by the low cost of the upgrade (of $59.2M). The upgrade pushes more power into load centers such as Wichita and Kansas City and increasing congestion on Benton – Rose Hill 345 kV and Butler – Altoona 138 kV transmission lines. However, these factors are not sufficient to restrict the immense value provided by this network upgrade.

- Located in the southeastern portion of Oklahoma, near the Oklahoma/Texas border, the **Pittsburg – Valliant 345 kV (NU# 12)** network upgrade helps facilitate the transfer of power from the North and West towards Arkansas and Louisiana. This network upgrade eliminates congestion on the existing Pittsburg – Valliant 345 kV line circuit 1 and reduces congestion on Hugo – Valliant 345 kV line. However, the inclusion of the upgrade creates new congestion on the Valliant – Lydia 345 kV line that offsets some of the savings discussed above and leads to lower B/C ratio of 0.3. SPP identified Valliant – Lydia 345 kV 2nd circuit as a network upgrade in the same DISIS study cluster. Incorporating this upgrade would potentially increase the benefits ($86.2M) that the line currently provides.

5.2. Conservative Aspects of Key Study Assumptions

ICF's reliance on Future I assumptions for assessment of benefits of transmission upgrades should be considered a conservative assumption. All else equal, higher renewable capacity associates with each network upgrade will yield higher system benefits. As observed for NU#4, the APC savings attributed to the network upgrade increased by nearly $34M as the percentage of GI capacity associated with the network increased from 21% in year 5 to 47% in year 10. Inclusion of higher renewable builds could potentially yield significant benefits.

This study examined a selection of proposed network upgrades in the two regions to determine their potential to provide benefits associated with APC savings. It assumed network upgrades would be built primarily to interconnect the associated generation resources. Aspects of transmission planning that could enhance market efficiency benefits were not incorporated explicitly. In particular, the study was designed to test the one-off addition of single network upgrades. The only difference between the Reference Case and each of the change cases was the addition of a single transmission network upgrade. As a result, the economic benefits evaluated and described in this report are conservative and may understate the full benefits of the projects to consumers.

As discussed above, ICF observed increased congestion on existing corridors after the network upgrade was incorporated as the main driver lower savings. Some of the observed chokepoints were identified in the DPP/DISIS studies along with the network upgrade of interest. While additional sensitivity analysis needs to be performed, it is likely that if assessed as a portfolio, these upgrades may yield significantly higher APC savings in addition to reliably integrating the renewables.

In addition, the associated generation resources were not derated in the Reference Case without the network upgrade. In real world operations the output of generators may be limited by the operator in the absence of required network upgrades. This approach significantly understates the actual production cost savings associated with each network upgrade. A sensitivity was conducted to demonstrate the effect of this assumption on the APC savings associated with Franklin – Baxter Wilson 345 kV line. As discussed above, this line provides relatively low net benefits in the reference scenario. However, in the de-rate scenario, in which 92% of renewables assigned to the network upgrades are excluded from the Base Case and only assumed in the Change Case along with the network upgrade that is being evaluated, APC savings increased by an average of nearly $87M and yielded a B/C ratio to 2.03 (as compared with 0.12 in the reference case).

Finally, as noted some network upgrades yielded substantial savings in spite of GI capacity match rate. This was attributed to the ability of the network upgrade to mitigate some of the existing transmission bottlenecks. ICF did not select projects based on their ability to relieve existing constraints. As shown in Section 4, the criteria for screening and shortlisting the upgrades was to ensure that all regions within both markets are represented, the voltage class, level of GI capacity that was identified as potentially limited in its ability to deliver its output to the load and persistence of the issue. The benefits could have been higher if the selection process included consideration for addressing persistent congestion.

6. CONCLUSION

The cost of transmission network upgrades in MISO and SPP have become a significant hurdle for the integration of low-cost new renewable generation. In addition to the direct interconnection costs, generators are being required to fund increasingly more expensive network upgrades because the network is over-subscribed. Both markets allocate most, if not all, of the network upgrade costs to the generation developer.

Using very conservative assumptions, this study evaluated the economic benefits of a representative sample of network upgrade projects assigned through the MISO and SPP GI process over the last seven years. The results show that the network upgrades provide benefits to consumers that can exceed their allocated costs, resulting in an inconsistency between the payments and the benefits received. Of the 12 network upgrades reviewed, ten provided positive benefits to consumers, with eight having benefits that exceeded 10% of the costs.

Because of the conservative nature of the study, the economic benefits evaluated and described in this report may understate the full benefits of the projects to consumers. A sensitivity analysis on one of the network upgrades demonstrated that under real world operating conditions, the network upgrades could provide significantly higher benefits to the system.

The study shows that the network upgrades identified through the DPP and DISIS studies provide broader regional benefits resulting in real value to consumers. Understanding these potential areas of consumer benefits can help policy makers and other stakeholders to determine how to leverage such projects to the advantage of customers, while ensuring that costs are allocated equitably.

EXHIBIT 6

Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs

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NOTICE

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The report also incorporates research from our prior client engagements and public reports, including:

- Gramlich and Caspary, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure,* January 2021.
- Pfeifenberger, Ruiz, Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, published by Boston University's Institute for Sustainable Energy, September 1, 2020.
- Pfeifenberger and Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future*, prepared for WIRES May 2016.
- Gramlich and REBA Institute, *Designing the 21st Century Electricity System*, for Renewable Buyers Alliance Institute, March 2021.
- Caspary, Goggin, Gramlich, Schneider, Disconnected: The Need for a New Generator Interconnection Policy, for Americans for a Clean Energy Grid, January 2021.
- Pfeifenberger, Chang, and Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES, April 2015.
- Chang, Pfeifenberger, Hagerty, *The Benefits of Electric Transmission Identifying and Analyzing the Value of Investments*, prepared for WIRES, July 2013.

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Executive Summary

The U.S. is at a critical juncture in transmission network planning. System vulnerabilities to severe weather are illuminating the need and opportunity for transmission to enable power sharing across and between regions. Existing transmission infrastructure, mostly constructed in the 1960s and 1970s, is nearing the end of its useful life, and decisions today about how this aging infrastructure is replaced will have long-lasting impacts on system costs and reliability. At the same time, public policy mandates, customer preferences, and the power generation mix necessary to address these needs are rapidly changing, causing a need for various types of transmission in different locations to maintain reliable and efficient service.

While the current transmission system and grid planning processes have functioned adequately in the past, they are failing to address these diverse 21st century needs. Current transmission planning processes routinely ignore realistic projections of the future resource mix, how the transmission system is utilized during severe weather events, and the economies of scale and scope that can reduce total costs. Today's planning is overwhelmingly reactive and focused on addressing near-term needs and business-as-usual trends.

The large majority of current transmission investments are narrowly focused on network reliability and what is needed to connect the next group of generators in interconnection queues, ignoring the efficiencies that occur when simultaneously and proactively planning for multiple future needs and benefits across the system. Even if Planning Authorities look beyond reliability-driven needs, they typically compartmentalize transmission into individual planning efforts that separately examine reliability, economic, public policy, and generator-interconnection driven transmission projects—instead of conducting multi-value planning that optimizes investments across all reliability, economic, public policy, or generator interconnection needs. The current approaches also lack a proactive scenario-based outlook that explicitly recognizes long-term planning uncertainties.

Together, these deficiencies yield an inefficient patchwork of incremental transmission projects and they limit the planning processes' ability to identify more cost-effective investments that meet both current and rapidly changing future system needs, address uncertainties, and reduce system-wide costs and risks. The inevitable outcome of such reactive and siloed planning is unreasonably high overall system costs and risks, which are ultimately passed on to electricity customers and can deter the development of low-cost generation resources.

Fortunately, there have been exceptions to the rule. Effective transmission planning efforts have proven repeatedly that proactive, multi-value, scenario-based planning delivers greater benefits to the entire electric system at lower overall costs and risks. These holistic transmission planning efforts have led to well-documented, highly beneficial transmission investments across the United States.

The available industry experience thus points to the following proven planning practices and core principles with which transmission planning can achieve reliable and efficient solutions capable of meeting the needs of the evolving 21st century power system at a lower total system cost:

1. **Proactively plan for future generation and load** by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.
2. **Account for the full range of transmission projects' benefits** and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.
3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.
4. **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.
5. **Jointly plan across neighboring interregional systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

As set forth in greater detail in the remainder of this report, these principles form the standard for efficient transmission planning that can maintain a reliable grid while more cost-effectively meeting all other transmission-related needs to avoid unreasonably high electricity costs. Policymakers and planners need to reform current transmission planning requirements to avoid unreasonably high system-wide costs that result from the current planning approaches, thereby enabling customers to pay just and reasonable rates by implementing these principles.

I. Today's Transmission Planning Results in Unreasonably High Electricity Costs

This report focuses on improving transmission planning, including for generation interconnection, which consists of identifying transmission needs and evaluating and selecting solutions to address these needs. We recognize, however, that successful approval and development of planned transmission infrastructure also requires improvements to cost allocation and approval (including permitting) processes. Creating a more effective transmission planning and development process to build a grid that can cost-effectively meet 21st Century needs will require improving every phase of this process, as illustrated in the figure below. Improvements will have to specifically focus on: (1) expanding initial needs assessment and project identification; (2) improving the analyses of transmission solutions and their costs and benefits to determine the which are most effective from a total system-wide cost perspective; (3) refining project cost recovery (*i.e.*, cost allocation) to be roughly commensurate with benefits; and (4) presenting the needs, benefits, and proposed cost recovery to obtain approvals from the various federal and state permitting and regulatory agencies.

FIGURE 1. TRANSMISSION PLANNING PROCESS

Electricity costs consist of three major components: generation, transmission, and distribution costs. Transmission, the focus of this report, consists of the electrical wires and other equipment that transports electricity from generators to local distribution utilities. In many regions, including some served by regional transmission organizations (RTOs) or independent system operators (ISOs), these three functions are provided by one vertically integrated entity. Even in RTO areas with disaggregated generation and distribution ownership, transmission owners (TOs) are still primarily monopolies and affiliates of other utility entities.

Transmission currently accounts for about 13% of the total national average electricity costs, while generation accounts for 56% of the total.[1] Well-planned transmission investment reduces the total system-wide cost of electricity by allowing more electricity to be generated from lower-cost resources and making more efficient use of available generation resources. Unfortunately, current transmission planning processes fail to achieve the efficient quantity or type of investment needed to realize maximum reductions in generation costs and lowest total costs, which results in unreasonably high system-wide costs.

While the U.S. has recently been investing between $20 to $25 billion annually in improving the nation's transmission grid,[2] most of this investment addresses individual local asset replacement needs, near-term reliability compliance, and generation-interconnection-related reliability needs without considering a comprehensive set of multiple regional needs and system-wide benefits. In MISO, for example, baseline reliability projects and other, local projects approved through the annual regional transmission plan have grown dramatically since 2010 and have constituted 100% of approved transmission for the last three years and 80% since 2010.

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1 U.S. Energy Information Administration, *Annual Energy Outlook 2021*, 2021, p4.

2 See slide 2 of Pfeifenberger, Tsoukalis, *Transmission Investment Needs and Challenges*, JP Morgan Renewables and Grid Transformation Series, June 1, 2021.

TABLE 1. MISO MTEP APPROVED INVESTMENT BY PROJECT TYPE[3]

Year	Baseline Reliability Projects (BRP) ($ million)	Market Efficiency Projects (MEP) ($ million)	Multi-Value Projects (MVP) ($ million)	Other (local) ($ million)
2010	94	-	510	575
2011	424	-	5,100	681
2012	468	15	-	744
2013	372	-	-	1,100
2014	270	-	-	1,500
2015	1,200	67	-	1,380
2016	691	108	-	1,750
2017	957	130	-	1,400
2018	709	-	-	2,300
2019	836	-	-	2,800
2020	755	-	-	2,800

Most of the planning processes used today result in inefficient investments that increase total system-wide costs. The narrowly focused current approaches do not identify opportunities to take advantage of the large economies of scale in transmission that come from "up-sizing" reliability projects to capture additional benefits, such as congestion relief, reduced transmission losses, and facilitating the more cost-effective interconnection of the renewable and storage resources needed to meet public policy goals. Neither do the narrowly focused approaches identify investments that create option value by increasing flexibility to respond to changing market and system conditions. For example, in-kind replacement of aging existing facilities misses opportunities to better utilize scarce rights-of-way for upsized projects that can meet multiple other needs and provide additional benefits, thus driving up costs and inefficiencies. And the current piecemeal approach certainly does not yield any larger regional or interregional solutions, such as transmission overlays, that could more cost-effectively address the nation's public policy needs. In short, and as shown through examples below, the current approach systematically results in inefficient infrastructure and excessive electricity costs.

The current lack of proactive, multi-value, and scenario-based planning for future generation and policy needs in most of the U.S. creates a situation where we are essentially trying to plan

[3] Years 2010 through 2019 from Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, Section 206 Complaint and Request for Fast Track Processing, January 21, 2020 at 31–32. 2020 figures from *MTEP20* at p 15. See MISO, *MTEP 20 Full Report.*

an integrated and shared network through the generator interconnection, local upgrades, and reliability planning processes. The lack of proactive, multi-value planning also overburdens generators in the interconnection queue by making them responsible for network upgrades that provide large system-wide benefits.

A recent ICF study showed that generation developers essentially bear the entire cost of regional network upgrades required to interconnect generators, even though these upgrades often provide broad system-wide benefits.[4] PJM's proactive 2021 off-shore wind integration study (discussed below) shows the same: upgrades to accommodate generation interconnection requests provide broad system-wide benefits.[5] This cost allocation consequently is not roughly commensurate with benefits; having to bear the full costs of such upgrades forces many generation developers to withdraw their interconnection requests even if the network upgrade provides substantial regional benefits that exceed costs—resulting in inefficient outcomes and higher system-wide costs. In addition, many of the current generation interconnection processes do not provide interconnection options that rely on non-firm, energy-only injections that take advantage of generation re-dispatch or other solutions. Reforms consequently are needed to ensure cost-effective solutions that more fairly allocate transmission costs.

The higher system-wide costs and inefficiencies associated with the current planning approaches are evident when compared to different planning methods that have been applied to the same needs. For example, comparing the results of PJM's 2021 offshore wind integration analysis with the results of individual PJM generation interconnection studies shows that the current generation interconnection study process (evaluating one interconnection cluster at a time) approximately doubles the transmission-related interconnection costs of offshore wind generation compared to a more proactive, regional study process. Under PJM's current queue-based generation interconnection study process, the total costs of necessary onshore PJM network upgrades identified within individual PJM feasibility and system impact studies related

4 ICF Resources, *Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits*, prepared for American Council of Renewable Energy (ACORE), September 9, 2021. As the study notes, in SPP, 100% of the interconnection costs are assigned directly to generators in SPP. In MISO, generators are responsible for 90% of the cost for upgrades 345 kV and higher, with 10% allocated regionally

5 PJM, *Offshore Transmission Study Group Phase 1 Results,* presented to Independent State Agencies Committee (ISAC), July 29, 2021. See slide 24 for a discussion of the system-wide benefits associated with the network upgrades identified in this proactive study for interconnecting offshore wind generation.

to integrating 15.5 GW of offshore wind equals $6.4 billion.[6] This results in PJM onshore network upgrade costs that adds over $400/kW to the cost of the offshore generation (including offshore transmission), or roughly 13% of offshore generation capital costs.[7,8] By contrast, PJM's 2021 proactive region-wide study holistically evaluated onshore transmission investment needs to connect up to a cumulative 17 GW of offshore wind generation to its footprint (which reflects the offshore wind resource interconnection needs of multiple states' offshore wind plans).[9] This proactive regional study estimated only $3.2 billion in PJM onshore network upgrade costs would be needed for interconnecting 17 GW of offshore wind generation—less than half the costs identified through the individual interconnection request studies. This reduces average interconnection costs to $188/kW-wind, which is only 45% of the over $400/kW cost associated with the current reactive, incremental interconnection study approach. In addition, the regional PJM study found that these identified $3.2 billion in onshore network upgrades result in substantial additional regional benefits in the form of congestion relief, customer load LMP reduction, and reduced renewable generation curtailments that would not be realized using reactive interconnection methods.[10]

Thus, the July 2021 PJM offshore wind study shows that the reliability upgrades necessary to interconnect offshore wind generation needed to meet states' public policy goals also provide substantial benefits to a large portion of the PJM footprint beyond addressing interconnection-related reliability needs, thereby further reducing overall customer costs beyond the 50% of onshore transmission investment cost savings. Contrasting PJM's July 2021 study results to the results of its current interconnection study process demonstrates the inefficiency and excessive costs associated with the current reactive, interconnection- and reliability-driven planning process. The July 2021 PJM study is just one of many similar examples demonstrating the unreasonable expense and lost benefits associated with transmission planning processes that are not proactive and multi-value based.

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6 Based on costs from PJM's feasibility and system impact studies for individual generation interconnection requests as reported in Burke and Goggin, *Offshore Wind Transmission Whitepaper*, October 2020 at p. 40.

7 Reported global project data suggest a decline of the weighted average capital cost of offshore wind capacity to $3,000/kW by the mid-2020s. National Renewable Energy Laboratory, *Offshore Wind Market Report: 2021 Edition*, prepared for U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, DOE/GO-102021-5614, August 2021.

8 If offshore wind generators accept the allocation of these onshore upgrade costs, they will need to pass them on to their wholesale customers, which then pass them on to retail customers, increasing electricity rates.

9 PJM, *Offshore Transmission Study Group Phase 1 Results,* presented to ISAC, July 29, 2021. Across six scenarios studied by PJM, the identified onshore upgrade costs range from $627 million to $3.2 billion for OSW injections ranging from 6.4 GW to 17 GW.

10 *Id*., slide 24.

Similarly, the optimized transmission plans produced as part of PJM's 2014 renewable generation integration study to accommodate large additions of wind, offshore wind, and solar resources also find lower interconnection costs than the individual PJM's interconnection studies. That 2014 study identified transmission costs of $106/kW of renewable generation to integrate the then-projected 35 GW of additional wind and solar capacity needed to meet the PJM-wide RPS requirements of 14%. For a 20% PJM-wide RPS requirement, the cost ranged from $57–$74/kW of new renewable capacity, depending on the mix of wind, offshore wind, and solar capacity.[11] The fact that renewable generation-related interconnection costs are so much lower in the 20% RPS cases than the 14% RPS case confirms the large economies of scale that are captured from a more proactive regional evaluation of transmission needs, further bolstering the case for proactive regional planning for public policy needs rather than relying on incremental reactive upgrades through the generation interconnection process.

Comparing the proactive 2021 and 2014 PJM studies with the results from PJM's individual generation interconnection studies clearly highlight how the current generator interconnection process is unreasonable in two ways. First, the current interconnection process leads to much higher-cost solutions for achieving state clean energy policies, which unreasonably increases overall electricity costs. Second, given the identified system-wide benefits, allocating 100% of the identified interconnection project costs to the interconnecting generators or participant funding does not yield an outcome in which all beneficiaries pay costs that are roughly commensurate to the benefits they receive. Allocating the entire costs of the interconnection-related network upgrades to generators, ignores that PJM's own studies found large benefits associated with these upgrades accrue to other PJM market participants and customers.

Across all FERC-jurisdictional ISO/RTOs, the current approach of identifying and funding network upgrades through the generator interconnection process is becoming unworkable as costs and queue backlogs increase. Grid Strategies' January 2021 report on interconnection

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[11] Transmission costs obtained from PJM scenarios were divided by the wind and solar capacity added in each RPS scenario (minus 5,122 MW of existing wind and 72 MW of existing solar. *PJM Renewable Integration Study, Task 3A Part C*, GE Energy Consulting prepared for PJM Interconnection, March 31, 2014, p 16. *Final Report: Task 2 Scenario Development and Analysis*, GE Energy Consulting prepared for PJM Interconnection, January 26, 2012.

Note that these projected costs of future upgrades, however, are still higher than the average of historical upgrade costs of generation interconnection request (in large part taking advantage of existing grid capabilities) as documented by the Lawrence Berkeley National Laboratory as reported in Will Gorman, Andrew Mills, Ryan Wiser, *Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy*, preprint version of a journal article published in *Energy Policy*. DOI: https://doi.org/10.1016/j.enpol.2019.110994, October 2019, p 12.

queues shows that recent network upgrade costs are 2 to 5 times higher now that the existing transmission capacity has been fully subscribed.[12] For example, the identified upgrade costs for recent entrants into the interconnection queue in western MISO now exceed $750/kW.[13] In contrast, the cost per kW for proactive regionally planned network solutions in these areas has been much lower. For example, the interconnection costs associated with MISO's Multi Value Projects (MVPs) was only approximately $400/kW in today's dollars even before netting out any system-wide benefits.[14] As quantified in the next section, the MVP projects and other comprehensive network solutions designed with multi-value planning approaches provide many other quantified benefits in addition to interconnecting generation, thereby reducing the net cost of generator interconnection.[15]

Since MISO approved its portfolio of MVPs a decade ago, MISO's 2014 MRITS study documented that even lower generation interconnection costs can be achieved if planned regionally rather than integrating renewable generation through the current interconnection process. This 2014 study found that MISO-wide transmission expansion of $2.567 billion would allow the interconnection of 17,245 MW of new wind capacity, at a cost of only $149/kW of wind.[16] The cost per kW may be lower because, unlike the MVP study, this study was not attempting to co-optimize regional economic and reliability benefits, which may yield lower transmission costs but higher net costs. However, comparing the $149/kW cost from the 2014 MRITS study to the $750/kW costs identified for the current interconnection queue in western MISO shows that proactively planned network additions are superior to incremental upgrades through the generation interconnection process. Given that MISO's 2014 Study yielded a plan that made extensive use of 345-kV transmission lines, it is not surprising that it could have achieved economies of scale and produced significant savings relative to the cost of incremental upgrades identified through the interconnection queue—documenting the high cost of the current planning process and the significant savings that could be realized through

[12] J. Caspary, M. Goggin, R. Gramlich, J. Schneider, *Disconnected: The Need for New Generator Interconnection Policy*, Americans for a Clean Energy Grid, January 14, 2021, at pp 8–11

[13] For example, the average cost for wind projects in MISO's August 2017 Definitive Planning Phase 2, West was $756/kW.

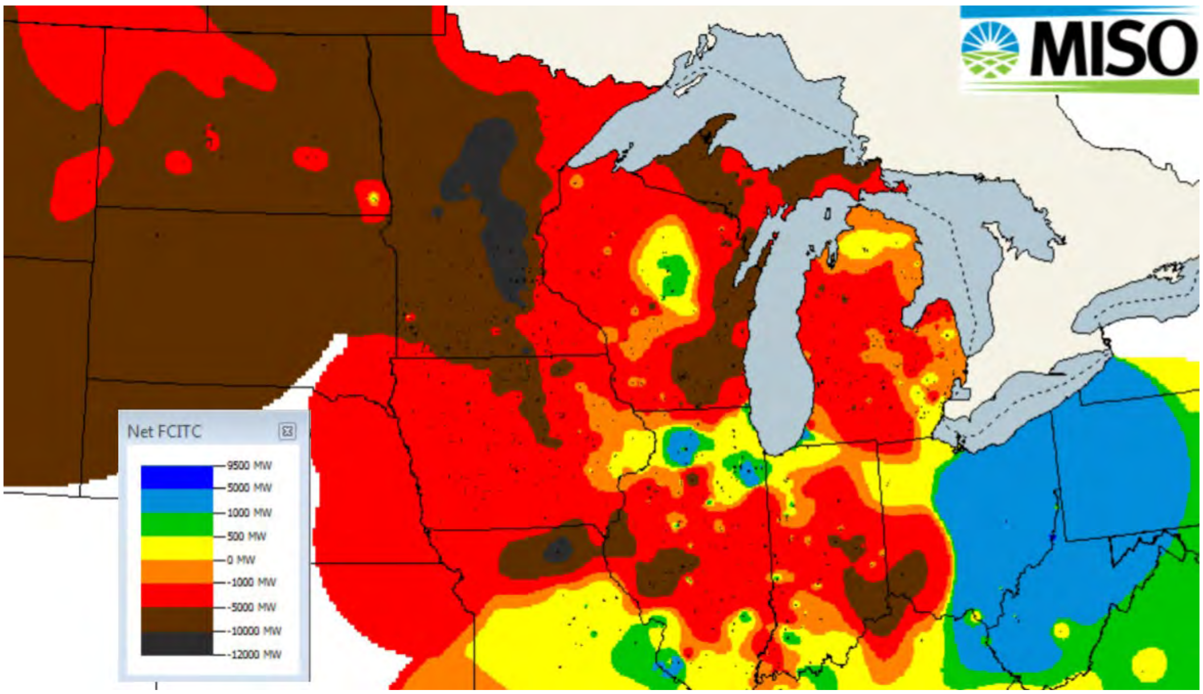
[14] The MVP lines cost $6.57 billion, per MISO, *Regionally Cost Allocated Project Reporting Analysis, MVP Project Status July 2021*, and were designed to interconnect 15,949 MW of wind, per MISO, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio*, September, 2017, which yields $412/kW of wind.

[15] MISO's quantification of MVP-related benefits estimated that the total benefits of the transmission portfolio exceeds its total cost by a factor of 2.2-3.4. *Id.* at p 4.

[16] GE Energy Consulting with MISO, *Minnesota Renewable Energy Integration and Transmission Study: Final Report*, October 31, 2014 at pp 4−21.

more proactive regional planning. Given MISO's analysis showing most of western MISO has a "transmission capacity deficit" of between 5,000 and 10,000 MW,[17] the brown areas in the map below, it is not surprising that the incremental upgrades produced through the current planning process are insufficient and unreasonably expensive solution to address regional transmission needs.

FIGURE 2. TRANSMISSION INTERCONNECTION CAPACITY DEFICIT IN MISO



Source: MISO, 2018.

Cost savings from regionally planned networks are confirmed by a 2009 analysis from Lawrence Berkeley National Laboratory (LBNL). The 2009 study reviewed 40 detailed transmission planning analyses for interconnecting wind generation and found the median cost of planned regional transmission was $300 per kW of wind (roughly $400/kW in today's dollars),[18] almost identical to the cost of the MISO MVP lines. That study also found strong evidence of cost reductions from comprehensive regional planning of transmission solutions that take into consideration a broad set of benefits (compared to relying on piecemeal upgrades planned

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[17] MISO, *August 2017 Definitive Planning Phase Model for Central, MI, ATC, and South regions. August 2016 model for West region*, July 11, 2018.

[18] Andrew Mills, Ryan Wiser, and Kevin Porter, *The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies*, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-1471E, February 2009; $300/kW corresponds to $383/kW today based on the increase in the consumer price index from 2009 to 2021.

solely for the interconnection of new wind resources). As the authors conclude from their review of 40 studies:

> we find that transmission designed to accommodate the full nameplate capacity of all new generation during peak periods on sparsely interconnected transmission lines appears to have a higher cost than transmission designed to reduce congestion costs caused by new wind generation based on an economic dispatch of an interconnected transmission network. This finding may have implications for future transmission planning efforts oriented toward accessing additional wind energy.[19]

The LBNL authors argue that the median transmission cost per kilowatt of wind across these studies likely overstates the true cost by not reflecting the system-wide benefits of interconnecting wind through comprehensive transmission planning. As they explain, their "methodology assigns the full cost of the transmission line to the wind plant without taking into account the other benefits of the transmission line," after noting that "in reality, however, studies frequently point to the additional reliability benefits and congestion relief that new transmission will provide. In these cases, our methodology overstates the transmission costs that are attributable specifically to wind."[20]

While this LBNL study was conducted 12 years ago, the fundamental economic and physical factors driving the economies of scale and broader benefits of comprehensive, regionally planned network upgrades are the same today.[21] Recent analysis, such as the savings identified in PJM's proactive offshore wind plan relative to PJM's interconnection queue results, as discussed above, also confirms the high cost of the current reactive planning process and the cost savings and larger benefits of proactively planned transmission compared to the cost of incremental additions designed to address specific needs like generator interconnection.

While it is surely true that in some cases an incremental single project designed to address a specific need may be more efficient than a larger-scale regional solution, the efficiency of the choice will be known if the planning process quantifies and considers all the benefits and costs of the alternatives. Such a benefits-and-cost-based planning process is important for developing

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[19] *Id.,* at xii

[20] *Id.,* at 27

[21] For a more comprehensive discussion of these underlying factors, see pp 3–5 and 29–30 at American Wind Energy Association (AWEA), *Grid Vision: The Electric Highway to a 21st Century Economy*, May 2019.

cost-effective transmission plans and investment strategies, valuing future investment options, and identifying "least-regrets" projects. Any least-regrets planning approach, however, needs to consider *both* (1) the possible regret that a project may not be cost effective in a particular future; *and* (2) the possible regret that customers may face excessive costs due to an insufficiently robust transmission grid in other futures.[22] A recent example of system planners failing to adequately consider the implications of insufficient expansion of interregional transfer capability to address extreme market conditions is the August 2020 blackouts in California. The final root cause analysis released by California policymakers concluded that "transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint" and "more energy was available in the north than could be physically delivered."[23] CAISO had similarly concluded after the 2000-01 California power crisis, that the crisis and its extremely high costs could have been avoided if more interregional transmission capability had been available to the state.[24]

Even if the share of transmission relative to the total electricity cost increases above today's level, that is not an indication of inefficiency or consumer harm. To the contrary, well-planned transmission investments can have a significant impact on reducing overall costs of delivering reliable electricity. As generation costs continue to fall and transmission needs to provide resilience, reliability, and system efficiency rises, transmission costs may rise as a percentage of total electricity system costs, but system-wide total costs will be lower than they would be with less transmission investment.

Many recent studies that apply proactive, multi-value planning principles have shown the large benefits and overall cost reductions that a more robust transmission system can provide for the

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[22] For a more detailed discussion on how transmission planners can use scenarios proactively to consider long-term uncertainties and the potentially high cost of insufficient infrastructure and associated risk mitigation benefit in transmission planning, see Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015, pp 9–19 and Appendix B.

[23] California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and California Energy Commission (CEC), *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*, Final, January 13, 2021, p 48.

[24] CAISO estimated that if significant additional transmission capacity had been available during the California energy crisis from June 2000 to June 2001, electricity customer costs would have been reduced by up to $30 billion over the 12 month period during which the crisis occurred CAISO, Transmission Economic Assessment Methodology (TEAM), June 2004, p ES-9.

nation's future power system. Some studies show the need for a doubling[25] or tripling[26] of the nation's existing transmission capacity over the next several decades. These studies evaluate the location and timing of output from load and generation and co-optimize across generation and transmission. They find that transmission investments typically enable significant savings in generation costs. Numerous additional studies, listed in Appendix A, show that for varying resource-mix scenarios, large expansion of transmission is needed to achieve cost-effective outcomes, particularly investment in transmission facilities that enable long distance large-volume transfers of energy across regions and across the country and continent. While the cost of these transmission investments would be significant, it only makes up a small portion of total electricity system investment needs (likely under ten percent of total cost).

One such study finds that well-planned transmission expansion results in additional transmission costs of about a half a cent per kWh on average (well under ten percent of total cost) but—in combination with a national policy goal for a zero carbon grid— would result in system-wide cost reductions of over 40% compared to relying on transmission-limited regional and state-level solutions.[27] Figure 3 below displays transmission costs, shown as the gray slice near the top of the bars (and the cost of wind, solar, and storage resources shown as the blue, orange, and green slices below), of decarbonizing the U.S. electricity grid. Another study finds transmission costs of about a quarter cent per kWh, or well under 5% of the total cost of electricity, even with a large-scale buildout of transmission.[28]

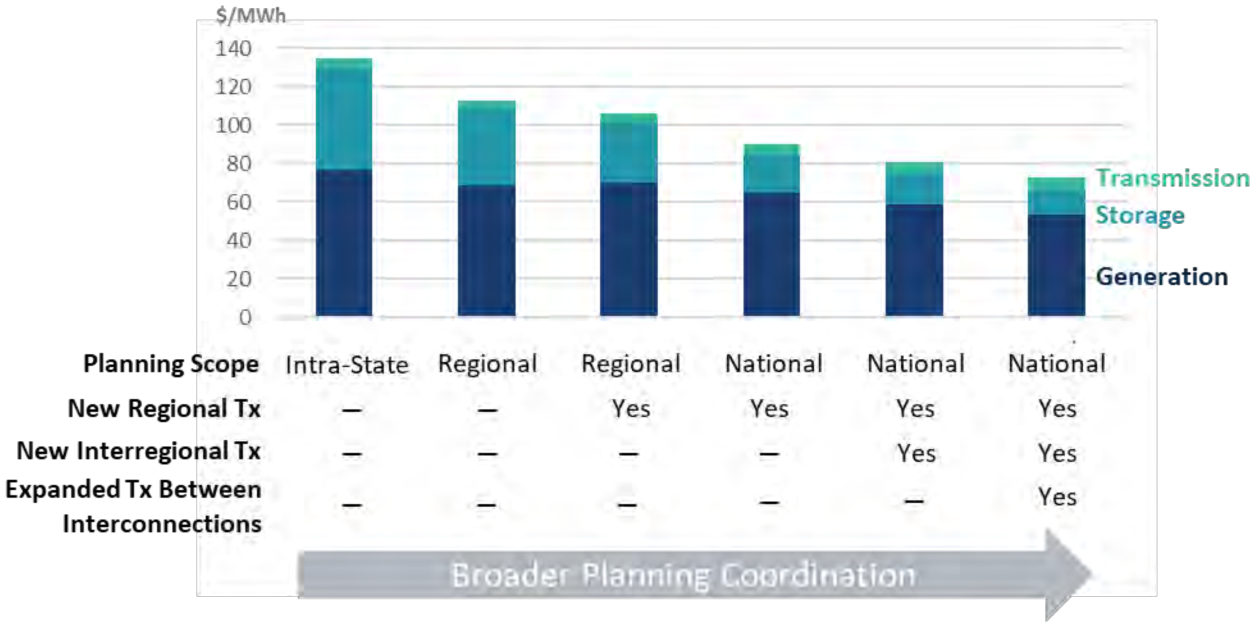
[25] P. R. Brown and A. Botterud, "*The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*," *Joule*, Vol. 5, No. 1, p115–134, January 20, 2021.

[26] E. Larson, C. Greig, J. Jenkins, E. Mayfield, A. Pascale, C. Zhang, J. Drossman, R. Williams, S. Pacala, R. Socolow, EJ Baik, R. Birdsey, R. Duke, R. Jones, B. Haley, E. Leslie, K. Paustian, and A. Swan, *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, interim report, Princeton University, Princeton, NJ, December 15, 2020.

[27] P. R. Brown and A. Botterud, *op. cit.*

[28] C.T.M. Clack (Vibrant Clean Energy LLC), M. Goggin (Grid Strategies LLC), *et al.*, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S*, Americans for a Clean Energy Grid, October 2020., at 9.

FIGURE 3. ELECTRICITY SYSTEM COSTS BY TYPE AND TRANSMISSION PLANNING SCENARIO



Source: Figure displays from data provided by MIT researchers Peter R. Brown and Audun Botterud based on their work modeling the decarbonization of the U.S. electricity system. Scenarios vary by the three planning parameters: (1) geographical scope, (2) whether new regional DC transmission is allowed, (3) whether new interregional DC transmission is allowed, and (4) whether new interconnectional transmission between East, WECC, and ERCOT is allowed.

It is clear that most of the current transmission planning processes are not leading to a cost-effective transmission infrastructure. Fortunately, some examples of better transmission planning, using existing and readily available tools, exist. While these experiences with improved planning process account for only a small portion of nation-wide transmission investments, they provide models for planning processes that, if broadly adopted by the nation's transmission planners, would yield better transmission solutions and lower system-wide costs.

II. Current Planning Generally Fails to Incorporate All Benefits, Scenarios, Portfolios, and Future Needs

Most of the planning processes used today result in inefficient investments that increase total system-wide costs. The table below shows which Planning Authorities are actually implementing these more-efficient planning methods, based on their most recent approved plans. While some of these entities are exploring improvements and have been performing relevant studies, in most cases their approved plans do not reflect these methods.

Table 2 shows the planning authorities' lack of use of proactive, scenario-based, multi-value processes. NYISO is applying this type of comprehensive planning framework in its public policy transmission planning process, but does not do so for addressing generation interconnection or reliability needs. CAISO has utilized such comprehensive planning when applying its TEAM approach, which reflects a multi-value transmission benefit framework that can effectively utilize scenarios, but the scope of benefits the CAISO considers outside of this process is limited. Similarly, MISO's MVP transmission planning benefit-cost analysis was an encouraging example of a comprehensive planning effort. However, since the MVPs were approved a decade ago, MISO's planning process has focused primarily on generation-interconnection and other reliability needs, a few minor market-efficiency projects based on narrowly defined benefits, and no other projects that were planned using MISO's multi-value approach.[29] While PJM has a "multi-driver" option in its planning process, it has never been used. PJM continues to rely primarily on its generation interconnection and reliability planning processes, which we showed in prior sections is much more costly than a comprehensive and proactive approach to build transmission. PJM's planning process for "market efficiency" projects considers only a narrow set of traditional production cost (load LMP) metrics and capacity market impact—which has yielded few such projects. Lastly, ISO-NE, Florida, Southeast Regional, and South Carolina Regional rank very low among the regional planning authorities, having rarely (if ever), applied any of the available comprehensive practices in their planning effort.

[29] Within MISO, American Transmission Company quantified a broad set of transmission benefits for range of different futures, but this process was used only for transmission siting cases before the Wisconsin Public Service Commission. MISO is also currently applying a proactive, scenario-based, multi-value planning framework in it RIIA effort, but has not yet approved any transmission projects based on it.

We offer the following criteria for the five efficient planning practices included in Table 2 below:

- **Proactively plan for future generation and load:** Incorporates a proactive perspective on reasonably anticipated load levels, load profiles, and generation mix over the lifespan of the transmission. Planning inputs extend beyond generic, baseline projections or considerations of such factors and actually include in the plans knowable information about enacted public policy mandates, publicly stated utility plans, and/or consumer procurement targets, which are used to evaluate the need, impacts, and benefits of the transmission.
- **Apply a <u>multi-value</u> planning framework to all transmission projects**: Accounts for a full range of transmission needs rather than separately assessing reliability, economic, and public policy needs. Quantifies and assesses a broad range of benefits, rather than narrow analyses based on traditional production cost savings.
- **Use <u>scenario-based</u> planning to address uncertainties**: Evaluates a set of distinct scenarios representing plausible futures (beyond the status-quo needs) that address the range of long-term uncertainties and also consider high-stress grid conditions. Incorporates plausible ranges of fuel price trends, locations and size of future load and generation, economic and public policy-driven changes to future market rules or industry structure, and/or technological changes to assess transmission effectiveness in multiple futures and any possible modifications needed from scenario differences.
- **Capture portfolio-synergy and use <u>portfolio-based</u> cost recovery**: Considers comprehensive portfolios of synergistic transmission projects to address system needs. Assesses benefits more accurately by taking into account network interactions, as well as other resources such as storage and other technologies. Applies portfolio-based cost recovery rather than a project-by-project cost-recovery approach.
- **Perform <u>joint interregional</u> planning:** Uses joint modeling and analysis of adjacent regions that jointly evaluates transmission regional and interregional needs and analyzes benefits based on multi-value framework, rather than being focused solely on each regions' needs and solutions independently of interregional needs and synergies.

TABLE 2. PLANNING AUTHORITIES CURRENT USE OF EFFICIENT PRACTICES

	Proactive Generation & Load	Multi-Value	Scenario-Based	Portfolio-Based[30]	Joint Interregional Planning
ISO-NE[31]	✗	✗	✗	✓	✗
NYISO[32,33]	✗	✗	✗	✗	✗
– PPTPP only	✓	✓	✓	✓	✗
PJM[34.35]	✗	✗	✗	✗	✗
Florida	✗	✗	✗	✗	✗
Southeastern Regional	✗	✗	✗	✗	✗
South Carolina Regional	✗	✗	✗	✗	✗
MISO (excl. MVP, RIIA)[36]	✗	✗	✗	✗	✗
SPP (ITP)[37,38]	✗	✓	✗	✓	✗
CAISO[39,40]	✓	✗	✓	✗	✓
– TEAM only	✓	✓	✓	✓	✓
WestConnect	✗	✗	✗	✗	✗
NorthernGrid[41]	✗	✗	✗	✗	✗

30 Includes portfolio-based cost recovery for projects approved by ISO-NE, NYISO, SPP, and CAISO. SPP also performs portfolio-based planning through its Integrated Transmission Planning (ITP) process.

31 ISO-NE transmission planning has been based solely on generation interconnection and network reliability needs. Cost recovery of network transmission costs, however, is broadly based on the entire ISO-NE portfolio (*i.e.*, utilizing postage stamp cost recovery)

32 NYISO applies proactive, multi-value, scenario-based planning only for the purpose of its Public Policy Transmission Planning Process (PPTPP). All other New York planning efforts, including for generation interconnection, remain solely reliability focused and individual (incremental) needs. In the most recent (2019) public policy transmission plan, transmission lines were studied using a base case, as well as a Clean Energy Standard + Retirement Scenario. See New York ISO (NYISO), *AC Transmission Public Policy Transmission Plan*, April 8, 2019, at p 14.

33 In the most recent (2019) public policy transmission plan, transmission lines were studied using: (1) a base case, (2) a Clean Energy Standard + Retirement Scenario, (3) a Clean Energy Standard +Retirement case with CO_2 emissions priced at the social cost of carbon. In a separate extended analysis, the NYISO studied two scenarios: (1) a base case, and (2) a case in which the capacity zones are reconstituted due to pending changes to the resource mix and the construction of the AC Transmission projects. See NYISO, *id.,* at pp 14, 19, and 25.

34 PJM's transmission planning manual has documentation on how PJM can develop a multi-driver approach. See PJM Transmission Planning Department, *PJM Manual 14B: PJM Region Transmission Planning Process, Revision: 49*, effective date: June 23, 2021, at p 32.

35 PJM and MISO Boards approved the first interregional market efficiency transmission project – replacement of the Michigan City-Trail Creek-Bosserman 138 kV line – based on a competitive planning process. See PJM, *RTEP: 2020 Regional Transmission Expansion Plan*, February 28, 2021, at p 2. The project has yet to be included in a MISO MTEP plan.

36 MISO's transmission planning manual has documentation on how to develop multi-value projects. See MISO, *Business Practices Manual: Transmission Planning*, Manual No. 020, BPM-020-r24, effective date, May 1, 2021,

To date, only a small portion of transmission spending is justified on economic criteria and full analysis of broader regional and interregional benefits and costs. Table 3 below shows what types of transmission are being planned based on recent spending as they report it (though in a number of cases the information was not readily available in time for publication of this report). As the table shows, the current planning processes do not consider the multiple values and wide-ranging benefits that well-planning transmission projects would be able to provide, which unreasonably increases system-wide costs.

at 160. MISO's transmission planning manual has documentation on constructing portfolios, and has approved and constructed MVP portfolios in the past. See MISO, *Ibid.*

Note that MISO has experience with pro-active, multi-value, scenario-based planning through its MVP and RIIA planning processes. However, no transmission projects have been approved through RIIA at this point and no MVPs were planned or approved by MISO in the last decade.

[37] SPP's multi-benefit Integrated Transmission Planning (ITP) process does not apply to generation interconnection. In SPP's screening of individual economic transmission projects, ITP projects are evaluated under only two "futures:" a reference case and an emerging technologies case. See SPP Engineering, *2020 Integrated Transmission Planning Assessment Report*, Version 1.0, October 27, 2020, at p 11.

[38] While SPP groups transmission into a "consolidated portfolio," all screened reliability projects are automatically included without further analysis. Economic projects are chosen based on the results of cost-benefit analyses; however, they are studied individually and the analysis does not account for the impacts of other economic lines in the portfolio. See SPP Engineering, *Id.*, p 81.

[39] CAISO's multi-value TEAM planning process is not utilized to address generation interconnection and network reliability needs. "CAISO's policy-driven transmission studies were based on a 60 percent RPS policy base portfolio provided by the CPUC, together with sensitivity portfolios based on higher approximately 71 percent – RPS levels." California ISO (CAISO), *2020–2021 Transmission Plan*, approved March 24, 2021, p 1.

[40] CAISO selects for approval of transmission elements that have a high likelihood of being needed and well-utilized under multiple scenarios: "1) the 2019-2020 Reference System Portfolio (RSP) adopted in the Decision, with the 46 million metric ton greenhouse gas target in 2030, as a policy-driven sensitivity, and (2) a portfolio based on the 30 million metric ton scenario, to test the impact of energy-only deliverability status for some generators on congestion and curtailment, as a second policy-driven sensitivity." CAISO, *Id.*, p 27.

[41] NothernGrid's 2020-2021 draft (and first ever) transmission plan has not yet been approved, but does offer a portfolio-based approach and includes a handful of proposed interregional lines. See Northern Grid, *Draft Regional Transmission Plan for the 2020–2021 NorthernGrid Planning Cycle*, n.d., pp 9 and 13.

TABLE 3. PLANNING AUTHORITIES'S RECENTLY APPROVED TRANSMISSION SPENDING FOR DIFFERENT TYPES OF PROJECTS ($ MILLION)

	Local Reliability	Regional Reliability	Economic	Generator Interconnection	Multi-Value Projects
ISO-NE	n/a	$437[42]	$0[43]	n/a	$0
NYISO[44]	n/a	n/a	n/a	n/a	n/a
PJM	$4,106[45]	$388.31[46]	$24.69[47]	$101[48]	$0
Florida	n/a	$0[49]	$0[50]	n/a	$0
Southeastern Regional	n/a	n/a	n/a	n/a	n/a
S Carolina Regional	n/a	n/a	n/a	n/a	n/a
MISO	$2,800[51]	$755[52]	$0[53]	$606[54]	$0
SPP	n/a	$213.5[55]	$318.8[56]	n/a	$0
CAISO	n/a	$3.6[57]	$0[58]	n/a	$0
WestConnect	n/a	n/a	n/a	n/a	n/a
NorthernGrid	n/a	n/a	n/a	n/a	n/a

42 See the list of transmission included under the most recent regional system plan (2019). The cost figure has been calculated for transmission defined as "planned." See ISO-New England, October 2019 ISO-New England Project Listing Update (Draft)–ISO-NE Public, Excel spreadsheet, October 2019. It is possible that some local reliability projects are included under this category, and likely that ISO-NE does not track local reliability projects in general.

43 "To date, the ISO has not identified the need for separate market-efficiency transmission upgrades (METUs), primarily designed to reduce the total net production cost to supply the system load." See ISO New England, *2019 Regional System Plan*, October 31, 2019 at 7.

44 NYISO does not report approved transmission investment cost figures.

45 PJM, *RTEP: 2020 Regional Transmission Expansion Plan*, February 28, 2021, p 259.

46 *Id*., p 259. Of the $413 million in baseline projects approved under the 2020 PJM Regional Transmission Expansion Plan, one interregional market efficiency project at a total estimated cost of $24.69 million was approved. See *Id.*, p 75.

47 *Id., p* 75.

48 *Id.*, p 2.

49 "The Regional Projects Subcommittee (RPS) has completed its proactive planning analysis per the Biennial Transmission Planning Process (BTPP). In summary, no potential [Cost Effective or Efficient Regional Transmission Solutions] CEERTS Projects have been identified." See Florida Reliability Coordinating Council, Inc. (FRCC), FRCC Proactive Planning Results and CEERTS Proposal Solicitation Announcement, April 21, 2021.

50 *Ibid.*

51 MISO, *MTEP 20*, n.d., full report, p 15.

52 *Ibid.*

53 *Ibid.* No market efficiency projects were approved.

PJM's recent offshore wind generation study (discussed earlier in the report) shows that this absence of a multi-value framework in the generation interconnection process means that costs are higher than they would be under a proactive planning framework and, in the case of generation interconnections, they are unfairly placed on generators when large benefits accrue to the system as a whole. Fair treatment would align cost allocation for generation-interconnection-related network upgrades with benefits. If under such a multi-value framework there are generator interconnection-related network upgrades that do not show material benefits for load, generators would still be responsible for these costs.[59] However, many generation-interconnection-related network upgrades do provide economic and reliability benefits to load. A multi-value framework would correctly allocate a commensurate share of project costs to load.

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54 *Ibid.*

55 SPP offers the project cost figures for approved reliability projects. See SPP Engineering, *op. cit.*, pp 4–5. It is possible that some local reliability projects are included under this category, and likely that SPP does not track local reliability projects in general.

56 SPP offers the project costs of approved economic projects. See SPP Engineering, *op. cit.*, pp 4-5.

57 CAISO, *op. cit.*, p 440 –higher end of cost estimates chosen for each. It is possible that some local reliability projects are included under this category, and likely that CAISO does not track local reliability projects in general.

58 *Ibid*.

59 GIR are responsible for network upgrades needed to accommodate the full output of the generator on a non-firm, energy-only basis (N-0 conditions with optimal re-dispatch).

III. Market and Regulatory Failures Cause Under-Investment in Regional and Interregional Transmission

The lack of planning for and investment in the type of cost-effective, beneficial transmission that is needed to achieve reasonable electricity costs is caused by structural and regulatory problems in the electric industry. Below we comment on several of these problems.

1. Small utility planning areas encourage local transmission planning while discouraging regional transmission planning

There are 329 transmission owners (TOs) in the country, each of which evolved out of the early industry structure of local utilities serving local load with local generation resources.[60] Nearly all of these utilities were vertically integrated for most of their history and many remain so. Under this model, transmission was only built to serve the load and generation of the owner.[61] It was not until the late 1990s that regional operation and planning was introduced with the FERC Order 888 and the advent of RTOs and ISOs, and mandatory Planning Authorities were not established until FERC Order 1000 was issued in 2011.

Despite the formation of ISOs, RTOs, and regional Planning Authorities, much decision-making power over transmission planning and investments remains with the individual transmission owners. Planning authority over "local transmission" (which constitutes about half of the nation's transmission grid and is specifically exempt from regional planning requirements) has been retained by the individual transmission owners, which created barriers to coordinated planning over a larger regional footprint. Additionally, the regional planning efforts in the RTOs are collaborative processes that require broad consensus, as RTO membership is voluntary and individual members who do not support regional or interregional transmission investments

60 See NERC, Compliance Registry Matrix, tab "NCR Summary," under heading "TO." Accessed 10/2/2021

61 Vertically integrated utilities are generally monopoly entities that get full cost recovery through regulated, commission-approved rates.

have the option to leave the RTO. Regional planning outside of RTO areas is minimal to nonexistent.

2. Differing TO incentives between local transmission and regional plans leads to inefficient levels of each

TOs are allowed under current federal regulations to plan and install upgrades on their local systems without regional planning oversight; this also allows them to grow their transmission rate base on which they earn commission-approved rates of return, including incentive returns. While local transmission investment is necessary to replace aging infrastructure, regionally planned investments that address local needs may provide larger system-wide benefits. Some of these regionally planned projects may be bid out competitively, in which case incumbent TOs have to compete with independent third parties and are much less likely to end up owning the asset. Even where the incumbent TO wins a regional transmission project bid, the investment cost may be capped and the rate of return may have been reduced through the competitive bidding process. No such competitive pressure exists for local transmission facilities and many types of regional transmission, including any transmission that is not subject to regional cost sharing or that is located in states that (often at the urging of incumbent transmission owners) have prevented competitive bidding through their right of first refusal (ROFR). This creates a bias against larger regional solutions even if they are more innovative and cost-effective, but would involve cost sharing and competitive processes.

Current FERC regulations cause this regulatory failure. If there were not such a different ability to own and profit from regional vs local transmission, this bias would not exist.

3. Economies of scale cause inefficiently small investments unless mitigated through regulations

A very common “market failure” that is standard across regulated industries is the declining average cost at larger quantities of production, known as economies of scale. This physical and economic feature causes what is known as a “natural monopoly” in which the most efficient structure is to build and own large assets by a single company, with an economic regulator to determine the efficient level of investment and with cost recovery spread across all consumers. Economies of scale still exist in transmission such that the costs of high-capacity lines are much lower per unit of delivered energy than the cost of lower capacity lines. These economies mean that large regional lines would need to be planned through a regulatory process to achieve sufficient scale, rather than left to market forces alone or to processes where only small incremental upgrades are made by the local transmission owners. This regional planning process needs to function as intended to actually determine the most cost-effective scale of transmission investment, based on future needs over the life of the assets. This would require that the regional planning evaluate local transmission solutions and reject them if more cost effective regional solutions are available. The current planning processes, however, mostly accept the local transmission solutions (implemented by transmission owners outside the regional planning processes) and only add regional projects to address specific remaining needs, which are mostly reliability-only needs.

The current planning processes thus unreasonably lead to inefficiently small investments and higher system-wide costs by forgoing the economies of scale that regional projects would offer.

4. Economies of scope cause inefficient plans unless mitigated through regulations

When the production of one product reduces the cost of other products, there are "economies of scope." An apple orchard might sell both apple sauce and apples, for example, using the same inputs to production. In the case of transmission, there are a variety of uses and benefits that all come from the existence of high capacity transmission facilities. For example, transmission used to cover for the loss of generation due to extreme weather by sending power in the direction of the shortfall is also used to connect low-cost generation and reduce congestion costs, and vice versa. When transmission planning is based only on identifying least-cost transmission solutions for single drivers—such as generation interconnection and other reliability needs, economic and market efficiency needs, or public policy needs—these economies of scope provided by larger regional projects capable of simultaneously addressing multiple needs at both the regional and local transmission system levels are not captured, unreasonably raising system-wide electricity costs and rates.

Economies of scope can be captured only if multi-value/multi-driver planning is performed. Public policy that achieves cost-effective outcomes needs to require regional multi-value/multi-driver planning, particularly if the planning outcomes are not in the economic interest of TOs.

5. Externalities cause inefficient plans unless mitigated through regulations

When parties beyond the buyer and seller of a product are impacted, positively or negatively, from the transaction, that third-party impact is an "externality" of the transaction. Achieving efficient outcomes requires that the value of these externalities be taken into account. In transmission, electricity flows across the entire alternating-current network according to the laws of physics, which send power along the path of least electrical resistance (a function of the voltage levels, design, and length of transmission lines). For this reason, individual transactions and uses on the system impact all other transactions and uses. An expansion of transmission capacity to accommodate one transaction (or purpose) will thus increase or decrease capacity for other uses. The interactions of power flows across grid facilities also means that synergistic portfolios of transmission facilities can provide system-wide value that exceeds the value of the individual facilities.

Given the prevalence of network externalities, it is generally inefficient to plan transmission one line at a time and for one local (or even regional) system at a time. Efficiency requires planning a full portfolio of network assets together, across a wide geographic area. A transmission planning process that results in little regional (or interregional) capacity and only plans local or incremental regional upgrades at a time—and in response to a specific generator interconnection request or a single other need—will result in inefficient solutions that are unreasonably expensive from a system-wide perspective.

6. Horizontal market power

Another market failure in transmission relates to the exercise of horizontal market power, which is the power to withhold service to raise prices. Avoiding the exercise of such market power is a standard feature of the regulation of natural monopolies. Withholding is prevented by regulators requiring that all capacity is provided to any customer willing to pay the cost. For example, FERC's open access transmission regulations require that all "Available Transmission Capability" be provided to market participants. And the ability of entities with market power to raise prices is prevented by regulators establishing rates that are "just and reasonable," usually as a function of the total cost of providing the service. Thus, horizontal market power is largely addressed in the electric transmission industry through FERC regulations—but not completely.

Horizontal market power can still exist in electric transmission systems. When efficient transmission investments are not made by a TO with the power to determine which type of investments to make, then system-wide costs are increased. In the U.S. electric transmission industry, when more efficient regional and interregional transmission investments are not made due to barriers and biases in the planning processes such that less-efficient local and small regional upgrades are made instead, it is a form of unmitigated horizontal market power. A regulatory requirement to plan the efficient amount and scale of transmission, and charge only rates based on the cost of the efficient investment, is necessary to mitigate this market power.

7. Vertical market power

The ability to withhold service in one stage of production to increase profit in another stage of production is called vertical market power. Regulations that prevent the exercise of vertical market power are common in the electricity industry. If there were no such regulations related to the electric transmission system, TOs could withhold transmission and interconnection service from other market participants in order to increase the value of and the profits from their own generation. FERC open access rules introduced in 1996 through Order No. 888 and interconnection rules in Order No. 2003 are intended to mitigate the exercise of this type of vertical market power. But, again, these regulations are imperfect.

In the current electricity system, when interconnection and transmission planning processes are inefficient or even dysfunctional, then valuable transmission service is withheld, disadvantaging third party consumers and sellers, potentially advantaging a TO’s owned generation, and unreasonably increasing system-wide costs. Most TOs in the country still own generation and thus have incentives to underinvest in regional transmission and prefer less efficient local transmission solutions. Transmission planning requirements thus need to ensure that remaining opportunities to exercise vertical market power are removed.

Overall, these barriers and incentives serve to bias transmission planning against more innovative and cost-effective regional and interregional solutions to address the identified (multiple) transmission needs, the result of which is an inefficient outcome with higher system-wide costs.

IV. Adoption of Pro-Active, Scenario-Based, Multi-Value, and Portfolio-Based Transmission Planning Practices Is Necessary to Avoid Unreasonably High Electricity Costs

As discussed in prior sections, structural and regulatory problems in the electric industry have resulted in a lack of comprehensive planning for and investment in the type of transmission that offers the most cost-effective system-wide results. Fortunately, significant experience exists with proactive, scenario-based transmission planning that quantifies the wide range of economic, reliability, and public policy ("multi-value") benefits of transmission investments, whether it be individual projects or synergistic portfolios. This experience shows that proactive, scenario-based, multi-value planning yields infrastructure that lowers the overall, system-wide costs of supplying and delivering electricity.

In the cases when such comprehensive transmission planning processes have been used, the outcomes have yielded lower-cost results (even though without explicit but-for analysis, this difference in costs cannot always be quantified precisely). One example is Texas' proactive Competitive Renewable Energy Zone (CREZ) project. Recognizing the economic potential of connecting western Texas' sparsely populated wind-rich areas to load, the Texas legislature passed a bill in 2005 that ordered that the Public Utility Commission of Texas to develop a transmission plan to deliver renewable power to customers. The $7 billion effort was designed to interconnect around 11.5 GW of new wind generation capacity. After its 2013 completion, wind curtailment fell from a previous high of 17% to 0.5%.[62] Unforeseen at the time it was planned, interest in developing solar capacity in West Texas, as well as load growth from shale oil and gas production in the region, has further elevated the benefits of the projects.

Similarly, MISO's multi-value projects serve as another planning success story. Over 10 years ago, MISO began proactively planning in anticipation of the development of wind generation capacity to meet the state-by-state Renewable Portfolio Standards in its territory. Diverging from the standard planning processes, the MVP planning process identified a comprehensive

[62] ERCOT, *The Texas Competitive Renewable Energy Zone Process*, September 2017.

set of upgrades across its footprint that would provide a mix of reliability, policy, and economic benefits to the system under a range of scenarios. The resulting transmission infrastructure offers a broad range of regional benefits and has allowed over 11 GW of wind to be interconnected and delivered, with total benefits that are estimated to exceed project costs by $7 to $39 billion over the next 20–40 years.[63] In other words, without the proactively and regionally planned MVP portfolio, MISO's system-wide costs would be $7–$39 billion higher.

The California Independent System Operator (CAISO) also has extensive experience with evaluating a broad range of benefits for transmission projects as documented in CAISO's case study of the Palo Verde to Devers No. 2 project, which is discussed in more detail below. Nevertheless, this multi-value transmission planning experience has not been broadly applied in the CAISO's recent planning efforts. Rather, candidates for economically justified transmission projects have been evaluated based mostly on their impacts on wholesale market prices or their ability to reduce congestion charges based on either historically observed congestion charges or the congestion cost observed in base-case production cost simulations.

The Southwest Power Pool (SPP) has similarly found that the transmission upgrades it installed between 2012 and 2014 through its integrated planning process (ITP) yield a broad range of benefits that exceed $4.6 billion of project costs by nearly $12 billion over the next 40 years.[64] The $16.6 billion in total benefits is higher than SPP's multi-value transmission planning models had initially estimated, and 3.5 times greater than the cost of the transmission upgrades. SPP is the only RTO which regularly quantifies a broad range of transmission-related benefits in its planning and cost allocation process. In contrast, for example, while PJM also has experience quantifying a wide range of benefits for transmission projects,[65] it has not been utilizing any of this experience in its transmission planning process.

NYISO has recently added a multi-value planning framework through its Public Policy Transmission Planning Process (PPTPP), which has yielded a number of transmission projects with benefits in excess of project costs, thereby reducing system-wide costs.[66] However, NYISO is not applying this multi-value planning framework to its generation interconnection and reliability-driven planning efforts.

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63 MISO, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio*, September, 2017

64 Southwest Power Pool (SPP), *The Value of Transmission*, January 26, 2016.

65 PJM Interconnection, *The Benefits of the PJM Transmission System*, April 16, 2019.

66 NYISO, AC Transmission Public Policy Transmission Plan. April 8, 2019. Potomac Economic, *NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects*, February 2019.

Proactive, multi-value, scenario-based planning approaches have also been successfully utilized in other countries. For example, the Australian Electricity Market Operator (AEMO) has used scenario-based planning for a number of years after an independent review found that Australian transmission planning processes needed to be improved.[67] In the latest "Integrated System Plan" (ISP), the AEMO drew upon an extensive stakeholder engagement and internal and external industry and power system expertise to develop a blueprint that maximises consumer benefits through a transition period of great complexity and uncertainty.[68] The ISP serves the regulatory purpose of identifying actionable and future ISP projects, as well as the broader purposes of informing market participants, investors, policy decision makers and consumers.[69] As the AEMO explains, the ISP is based on the following principles:

- *Whole-of-system plan:* A plan to maximize net market benefits and deliver low cost, secure, and reliable energy through a complex and comprehensive range of plausible energy futures. It identifies the optimal development path for the National Electricity Market (NEM), consisting of ISP projects and development opportunities, as well as necessary regulatory and market reforms.
- *Consultation and scenario modelling:* AEMO developed the ISP using cost-benefit analysis, least-regret scenario modelling, and detailed engineering analysis, covering five scenarios, four discrete market event sensitivities, and two additional sensitivities with materially different inputs. The scenarios, sensitivities, and assumptions have been developed in close consultation with a broad range of energy stakeholders.
- *Least-regret energy system:* This analysis identified the least system cost investments needed for Australia's future energy system. These are distributed energy resources (DER), variable renewable energy (VRE), supporting dispatchable resources, and power system services. Significant market and regulatory reforms will be needed to bring the right resources into the system in a timely fashion.

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[67] A. Finkel, K. Moses, C. Munro, T. Effeney, and M. O'Kane, "*Independent Review into the Future Security of the National Electricity Market—Blueprint for the Future*," energy.gov.au, June 1, 2017, find that "Incremental planning and investment decision making based on the next marginal investment required is unlikely to produce the best outcomes for consumers or for the system as a whole over the long-term or support a smooth transition. Proactively planning key elements of the network now in order to create the flexibility to respond to changing technologies and preferences has the potential to reduce the cost of the system over the long-term" (at p 123)

[68] AEMO, *2020 Integrated System Plan*, July 30, 2020.

[69] Australian Energy Market Operator (AEMO), *Our 20-year plan for the National Electricity Market*, 2020. See also Transgrid, *Energy Vision 2050: A Clean Energy Future for Australia*, October 2020, as an example of a long-term, scenario-based energy industry and transmission grid analysis by one of the Australian transmission owners and developers, which explores alternative futures and their transmission implications through 2050.

- *Projects to augment the transmission grid:* The analysis identified targeted augmentations of the NEM transmission grid, and considered sets of investments that together with the non-grid developments could be considered candidate development paths for the ISP.
- *Optimal development path:* A path needed for Australia's energy system, with decision signposts to deliver the affordability, security, reliability and emissions outcome for consumers throughout the energy transition.
- *Benefits:* When implemented, these investments will create a modern and efficient energy system that is expected to deliver $11 billion in net market benefits and meets the system's reliability and security needs through its transition, while also satisfying existing competition, affordability, and emissions policies.

As we have shown with the examples in the prior section of this report, the current incremental and reactive transmission planning processes result in higher system-wide electricity costs than more proactive planning processes that simultaneously consider multiple needs and quantify a broad range of transmission benefits. The industry experience with such more effective planning and cost-allocation processes, where utilized, points to several core principles for transmission planning that can avoid these higher-cost traditional planning solutions.[70] The already-available experience with improved planning processes points to the following five core principles for efficient transmission planning:

1. **Proactively plan for future generation and load** by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.
2. **Account for the full range of transmission projects' benefits** and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.
3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.

[70] While this report focuses on the need to improve transmission planning processes, we recognize that addressing cost allocation challenges will also be an important element to the development of just and reasonable transmission solutions. For recommendations on improving cost allocation frameworks, see slides 25–30 of Pfeifenberger, *Transmission Planning and Benefit-Cost Analyses*, prepared for FERC Staff, April 29, 2021. See also P.L. Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector*, Economics of Energy & Environmental Policy, Vol. 10, No. 2 (2021).

4. **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.
5. **Jointly plan across neighboring interregional systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

The remaining section provides a more detailed examination of how these core planning principles work in practice.

1. Proactively Plan for Future Generation and Load

Most of today's transmission planning processes ignore the location, types, and quantities of the future generation mix needed to meet federal, state, utility, and customer clean energy goals, and thus do not consider how system needs will change as the grid continues to evolve. Looking further into the future to include knowable information about already enacted public policy mandates, publicly stated utility goals, and consumer preferences can identify more cost-effective grid solutions. From a system-wide cost perspective, the lack of proactive planning can lead to numerous piece-meal transmission upgrades that fail to holistically consider what is most cost-effective for the system over the 40–50 year life of the investments. Incorporating proactive forward-looking planning, identifies more efficient, integrated network solutions that cost significantly less than the sum of the often piecemeal upgrades identified through current planning processes.

As noted above, the recent PJM offshore wind integration study shows that the current generation interconnection study process (evaluating one interconnection cluster at a time) approximately doubles the onshore transmission costs of integrating offshore wind generation compared to a proactive planning process.

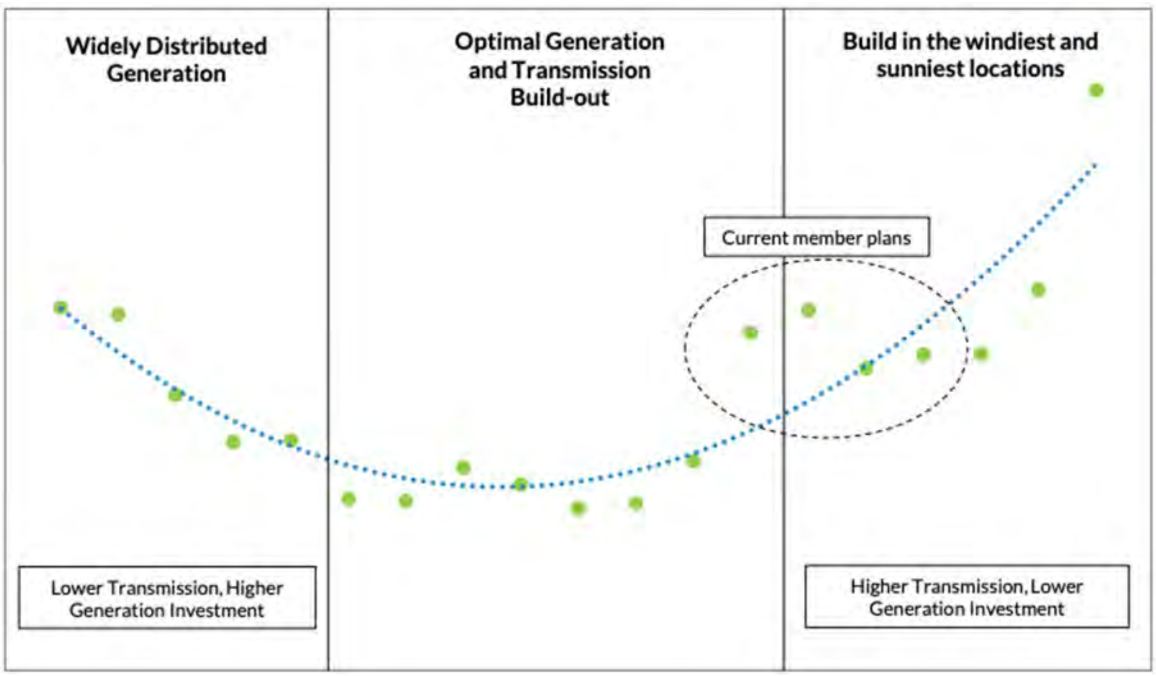
The MISO MVPs present another example of proactive forward-looking planning that resulted in transmission solutions that reduce system wide costs. The MVPs were the result of MISO's proactive planning effort prior to 2010, the Regional Generation Outlet Study (RGOS).[71] RGOS performed proactive planning and identified so-called "RGOS start projects." These projects were estimated to be beneficial in all scenarios evaluated by the study. These "no-regrets" RGOS start projects turned into the MVP portfolio that has allowed over 11 GW of wind to be integrated and delivered with system-wide cost savings (economic net-benefits) of $12–$53

[71] Midwest ISO (MISO), *RGOS: RGOS: Regional Generation Outlet Study*, November 19, 2010.

billion over the next 20–40 years.[72] MISO has found through its updated studies that the net benefits of the MVP portfolio exceed MISO's initial estimates.

Proactive planning also identifies transmission upgrades that guide the market towards the optimal mix of local and remote generation that can be delivered through the transmission grid. Local renewable generation can serve customers with less regional transmission but is often more expensive. Remote generation often has lower generation cost but requires more regional transmission. The trade-off can be evaluated through scenario-based proactive studies that consider generation in different locations and their transmission cost. The MISO "smile curve" illustrates this trade-off (Figure 4).

FIGURE 4. TOTAL MISO PROJECT GENERATION AND TRANSMISSION COSTS



Source: MISO Planning Advisory Committee, *Long Range Transmission Planning - Preparing for the Evolving Future Grid*, August 12, 2020, pg. 7.

Similarly, NYISO analyses of transmission projects evaluated under its public policy transmission planning processes (PPTPP) show significant benefits from placing up-sized public policy projects on the rights-of-way of aging existing transmission facilities, thereby avoiding the cost of the otherwise needed replacement of these existing facilities.[73] In fact, the avoided costs of

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[72] MISO, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio*, September, 2017.

[73] Newell, *et al.*, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, September 15, 2015.

aging facility replacement was one of the largest benefits identified for some of the public policy projected studied in in New York.

2. Account for the Full Range of Transmission Project Benefits, and use Multi-Value Planning to Comprehensively Identify Investments that address all Categories of Needs and Benefits

To identify solutions that result in lower overall costs to customers, planning needs to consider the multiple values (system-wide cost reductions) offered by transmission investments, irrespective of whether the primary driver of transmission infrastructure is based on reliability, public policy, or economic needs. For example, two solutions to address a particular reliability need may offer vastly different total system-wide benefits. Thus, the higher-cost transmission solutions can actually result in significantly lower net cost from a system-wide perspective. Multi-value transmission planning identifies these lower-total-cost solutions, by quantifying and considering a larger portion of total transmission-related benefits. Multi-value transmission planning can also inform policymakers about the system-wide costs of not investing in transmission to provide a more comprehensive picture of overall costs and benefits beyond transmission project costs.

Table 4 summarizes the benefits quantified and considered in four RTOs' multi-value transmission planning efforts. In addition to this RTO experience, many industry and academic studies have discussed the cost savings that transmission investments can provide and how to quantify them.[74] Most current transmission planning processes, however, do not consider these benefits. And even the few transmission projects approved under RTOs' "economic" (or "market efficiency") planning processes have been evaluated solely based on a very narrow set of benefits, such as production cost savings simulated under highly normalized system conditions. As the multi-value planning examples of RTOs and industry studies show, however, there already is much experience in quantifying a larger set of transmission benefits using existing evaluation tools.

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[74] For example, see: Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector*, Economics of Energy & Environmental Policy, Vol. 10, No. 2 (2021).

Pfeifenberger, *Transmission Planning and Benefit-Cost Analyses*, prepared for FERC Staff, April 29, 2021.

Pfeifenberger, Ruiz, Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, published by Boston University's Institute for Sustainable Energy, September 1, 2020.

Chang, Pfeifenberger, Hagerty, *The Benefits of electric Transmission Identifying and Analyzing the Value of Investments*, presentation prepared for WIRES, July 31, 2013.

TABLE 4. EXAMPLES OF EXPANDED TRANSMISSION BENEFITS ANALYSIS

SPP 2016 RCAR, 2013 MTF	MISO 2011 MVP ANALYSIS	CAISO 2007 TEAM ANALYSIS OF DPV2 PROJECT	NYISO 2015 PPTN STUDY OF AC UPGRADES
Quantified 1. **production cost savings** value of reduced emissions reduced AS costs 2. avoided transmission project costs 3. reduced transmission losses capacity benefit energy cost benefit 4. lower transmission outage costs 5. value of reliability projects 6. value of meeting policy goals 7. Increased wheeling revenues	**Quantified** 1. production cost savings 2. reduced operating reserves 3. reduced planning reserves 4. reduced transmission losses 5. reduced renewable generation investment costs 6. reduced future transmission investment costs	**Quantified** 1. production cost savings and reduced energy prices from both a societal and customer perspective 2. mitigation of market power 3. insurance value for high-impact low-probability events 4. capacity benefits due to reduced generation investment costs 5. operational benefits (RMR) 6. reduced transmission losses* 7. emissions benefit	**Quantified** 1. production cost savings (includes savings not captured by normalized simulations) 2. capacity resource cost savings 3. reduced refurbishment costs for aging transmission 4. reduced costs of achieving renewable & climate goals
Not Quantified 8. reduced cost of extreme events 9. reduced reserve margin 10. reduced loss of load probability 11. increased competition/liquidity 12. improved congestion hedging 13. mitigation of uncertainty 14. reduced plant cycling costs 15. societal economic benefits	**Not Quantified** 7. enhanced generation policy flexibility 8. increased system robustness 9. decreased nat. gas price risk 10. decreased CO2 emissions 11. decreased wind volatility 12. increased local investment and job creation	**Not Quantified** 8. facilitation of the retirement of aging power plants 9. encouraging fuel diversity 10. improved reserve sharing 11. increased voltage support	**Not Quantified** 5. protection against extreme market conditions 6. increased competition and liquidity 7. storm hardening and resilience 8. expandability benefits

Sources: SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016. SPP Metrics Task Force, Benefits for the 2013 Regional Cost Allocation Review, July, 5 2012; Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011; CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity; Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015.

Unfortunately, most existing planning processes do not take advantage of the available experience or consider the multiple values proposed transmission investment can provide beyond addressing specific drivers and needs. If a project is driven by reliability needs, the broader economic and public policy benefits provided by the project are usually not quantified and considered. If a project is categorized as an economic or public policy project, but simultaneously provides reliability benefits without addressing a specific reliability violation, that reliability benefit usually is not considered either. This particular "compartmentalized" or "siloed" planning approach leads to an understatement of transmission-related system benefits and a significant under-appreciation of the costs and risks imposed on customers by an insufficiently robust and flexible transmission infrastructure.

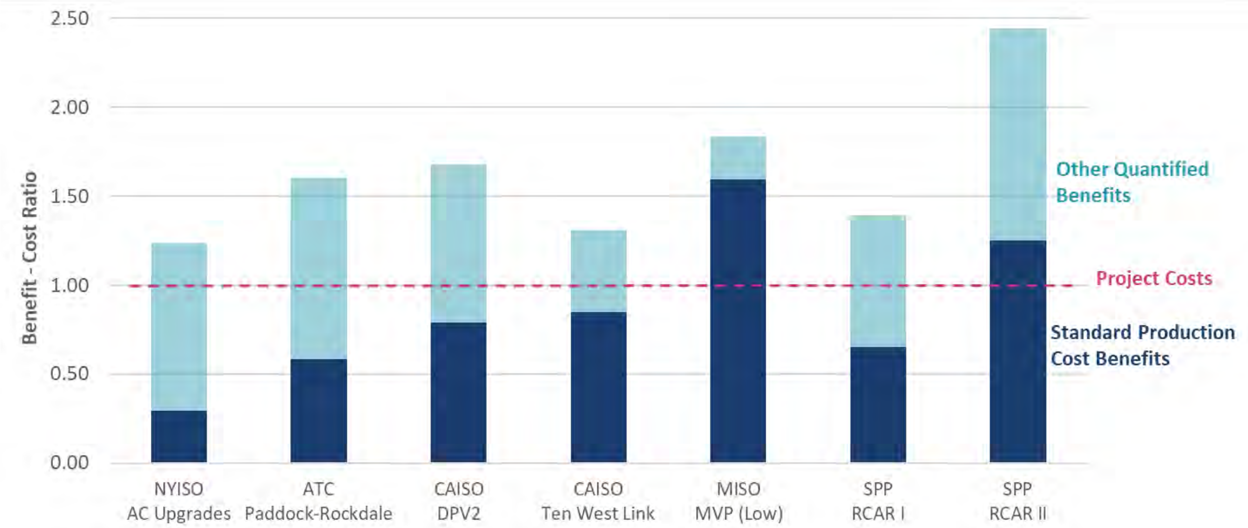
While not all proposed transmission investments provide benefits that exceed project costs, overlooking benefits because traditional tools and processes do not automatically capture these benefits leads to the premature rejection of valuable projects and underinvestment in transmission infrastructure. Many beneficial projects that have been built would not have passed cost-benefit ratios when only considering limited benefits, such as the traditionally quantified production cost benefits as shown in Figure 5 below. This leads to planning outcomes that impose unreasonable costs on customers.

Even though some of transmission-related benefits have been classified "unquantifiable" or "difficult to quantify," such as increased liquidity, the available industry experience shows that this is not the case. Many of these (frequently not quantified) transmission-related benefits can be readily estimated using existing planning and market simulation tools as the RTO examples in Table 4 and industry reports clearly show.

Quantifying a broader range of transmission benefits for individual projects or a portfolio of synergistic transmission upgrades will yield a more accurate benefit-cost analysis, provide more insightful comparisons, and would avoid rejecting beneficial investments that would reduce system-wide costs. Not quantifying these transmission-related benefits where they likely exist, results in unreasonably imposing additional costs on customers.

An effective multi-value planning process would: (1) consider for each project (or synergistic portfolio of projects) the full set of benefits transmission can provide (*e.g.*, as shown in Table 5); (2) identify the set of benefits that plausibly exist and may be significant for that particular project or portfolio; and (3) then focus on quantifying those benefits. This will yield a clear list of all benefits considered and quantified (along with those considered only qualitatively), akin to the list of quantified and not quantified benefits shown in industry examples of effective planning processes as summarized in Table 4 above.

FIGURE 5. BENEFIT-COST RATIOS OF TRANSMISSION PROJECTS WITH AND WITHOUT A BROAD SCOPE OF BENEFITS



Sources: Newell, *et al.* (The Brattle Group), Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, prepared for NYISO and DPS Staff. September 15, 2015. ATC uses expected benefits under "high environmental scenario." American Transmission Company, Planning Analysis of the Paddock-Rockdale Project, April 2007. CAISO, Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2), February 24, 2005. Testimony of Yi Zhang on Behalf of the California Independent System Operator, In the Matter of the Application of DCR Transmission, LLC for a Certificate of Public Convenience and Necessity for the Ten West Link Project, submitted to California Public Utilities Commission, Application 16-10-012, December 20, 2019. MISO, MTEP19 MVP Limited Review Report, 2019. Southwest Power Pool (SPP), Regional Cost Allocation Review (RCAR I), October 8, 2013. Southwest Power Pool (SPP), Regional Cost Allocation Review (RCAR II), July 11, 2016.

We continue this section with a review of the types of transmission-related benefits and how they can and have been quantified. We then describe efforts to integrate them into multi-benefit planning.

a. Types of Transmission Benefits

Most economic analyses used in transmission planning rely primarily on traditional applications of production cost simulations to determine whether the "adjusted production cost savings" (typically simulated only for highly normalized system conditions) offered by a transmission project exceed the project's costs. These production cost savings, adjusted for wholesale purchases and sales (or imports and exports), are mostly composed of fuel cost savings. The many RTO planning processes that are focused on traditional production cost savings do not examine or quantify the expanded set of well-known and tested transmission-related benefits, including (but not limited to): other production cost savings (*e.g.*, lower line losses and operating reserves), greater reliability and resilience, greater resource adequacy through reduced planning reserves and higher capacity value, and market benefits.[75] Compiled from the available RTO and industry experience, a full set of transmission-related benefits is listed in Table 5 and discussed further below.

TABLE 5. ELECTRICITY SYSTEM BENEFITS OF TRANSMISSION INVESTMENTS

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic "Day 1" market representation
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
4. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operational benefits

Benefits unrelated to electricity costs, such as jobs supported jobs supported, economic growth, and public health are shown in Table 6.[76]

[75] Chang, Pfeifenberger, Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, prepared for The WIRES Group. July 2013.

[76] We are not including these types of benefits, but rather limit the discussion to benefits that affect system-wide electricity costs as measure of whether rates paid by consumers are just and reasonable, which we understand is the main focus of FERC and the Federal Power Act.

TABLE 6. TRANSMISSION BENEFITS BEYOND ELECTRICITY SYSTEM IMPACTS

Benefit Category	Transmission Benefit
9. Employment and Economic Stimulus Benefits	Increased employment and economic activity; Increased tax revenues
10. Increased Health Benefits	Lower fossil-fuel burn can result in better air quality

1. Traditional Production Cost Savings

The most commonly used metric for measuring the economic benefits of transmission investments is the reduction in production costs. Production cost savings include savings in fuel and other variable operating costs of power generation that are realized when transmission projects allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies. Lower production costs will generally also reduce market prices as lower-cost suppliers will set market clearing prices more frequently than without the transmission project. The tools used to estimate the changes in production costs and wholesale electricity prices are typically security-constrained production cost models that simulate the hourly operations of the electric system and the wholesale electricity market by emulating how system operators would commit and dispatch generation resources to serve load at least cost, subject to transmission and operating constraints.

Within production cost models, changes in system-wide production costs can be estimated readily. These estimated changes, however, do not necessarily capture how costs change within individual regions or utility service areas. This is because the cost of serving these regions and areas will depend not only on the production cost of generating plants within the region or area, but will also depend on the extent to which power is bought from or sold to neighbors. The production costs within individual areas thus need to be "adjusted" for such purchases and sales. This is approximated through a widely used benefit metric referred to as Adjusted Production Cost (APC).

APC for an individual utility is typically calculated as the sum of (1) the production costs of generating resources owned by or contracted to the utility, plus (2) the net cost of the utility's market-based power purchases and sales.[77] The traditional method for estimating the changes

[77] For example, APC for a utility is typically calculated as: (1) the production costs of generating resources owned by or contracted to the utility, plus (2) the cost of market-based power purchases valued at the simulated LMPs

in the APC associated with a proposed transmission project is to compare the adjusted production costs with and without the transmission project. Analysts typically call the market simulations without the transmission project the "Base Case" and the simulations with the transmission project the "Change Case."

2. Additional Production Cost Savings

While production cost simulations are a valuable tool for estimating the economic value of transmission projects and have been used in the industry for many years, the specific practices continue to evolve. RTOs and transmission planners are increasingly recognizing that traditional production cost simulations are quite limited in their ability to estimate the full congestion relief and production cost benefits. These limitations, caused by simplifications in assumptions and modeling approaches, tend to understate the likely future production cost savings associated with transmission projects. As an example, failure to consider transmission's value of diversifying uncertain renewable generation through the transmission system can significantly under-estimate benefits.[78]

This is problematic, as in most cases, the simplified market simulations assume:

- No change in transmission-related energy losses as a result of adding the proposed transmission project;
- No planned or unplanned transmission outages;
- No extreme contingencies, such as multiple or sustained generation and transmission outages;
- Only weather-normalized peak loads and monthly energy (*i.e.*, no typical heat waves, typical cold snaps, or more extreme weather conditions);
- Perfect foresight of all real-time market conditions (*i.e.*, no day-ahead and intra-day forecasting uncertainty of load and renewable generation);
- Incomplete cycling costs of conventional generation;
- Over-simplified modeling of ancillary service-related costs (*e.g.*, assuming all operating reserves are deliverable);

of the utility's load locations (Load LMP), net of (3) the revenues from market-based power sales valued at the simulated LMP of the utility's generation locations (Gen LMP).

78 Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, BU-ISE, October 14, 2020.

- Incomplete simulation of reliability must-run conditions; and
- Unrealistically optimal system dispatch in non-RTO and "Day-1" markets.

Appendix B provides additional discussion regarding how to quantify the additional production cost savings (items 2.i through 2.x in Table 5 above) that are traditionally missed due to these simplifications.

3. Reliability and Resource Adequacy Benefits

Transmission investments will generally increase the reliability of the electric power system even when meeting reliability standards is not the primary purpose of the line. For example, additional transmission investments made to improve market efficiency and meet public policy goals also increase operating flexibility, reduce the risk of load shed events, and increase options for recovering from supply disruptions. This increase in reliability provides economic value by reducing the frequency, duration, and magnitude of load curtailments—or, alternatively, by reducing the planning reserve margins needed to maintain resource adequacy targets, such as a 1-day-in-10-year loss of load probability. These reliability benefits are not captured in production cost simulations, but can be estimated separately. Below we describe the categories of reliability and resource adequacy benefits.

i. Benefits from Avoided or Deferred Reliability Projects and Aging Infrastructure Replacement

When certain transmission projects are proposed for economic or public policy reasons, transmission upgrades that would otherwise have to be made to address reliability needs or replace aging facilities may be avoided or could be deferred for a number of years. These avoided or deferred reliability upgrades effectively reduce the incremental cost of the planned economic or public-policy projects. These benefits can be estimated by comparing the revenue requirements of reliability-based transmission upgrades without the proposed projects (the Base Case) to the lower revenue requirements reflecting the avoided or delayed reliability-based upgrades assuming the proposed projects would be in place (the Change Case). The present value of the difference in revenue requirements for the reliability projects (including the trajectory of when they are likely to be installed) represents the estimated value of avoiding or deferring certain projects. If the avoided or deferred projects can be identified, then the avoided costs associated with these projects can be counted as a benefit (*i.e.*, cost savings) associated with the proposed new projects.

SPP, for example, uses this method to analyze whether potential reliability upgrades could be deferred or replaced by proposed new economic transmission projects.[79] Similarly, a recent projection of deferred transmission upgrades for a potential portfolio of transmission lines considered by ITC in the Entergy region found the reduction in the present value of reliability project revenue requirements to be $357 million, or 25% of the costs of the proposed new transmission projects.[80] This method has also been used by MISO, which found that the proposed MVP projects would increase the system's overall reliability and decrease the need for future baseline reliability upgrades. In fact, MISO's MVP projects were found to eliminate future transmission investments of one bus tie, two transformers, 131 miles of transmission operating at less than 345 kV, and 29 miles of 345 kV transmission.[81] Similarly, NYISO has found that public policy projects that utilize the right of way of aging existing transmission facilities, often offer the significant benefit of avoiding having to replace the aging facility in the future.[82]

ii. Reduced Loss of Load Probability

Transmission provides tremendous flexibility to ensure reliable service through many situations, both predictable and unpredictable. Even if not targeted to address identified reliability needs, transmission investments can reduce the frequency and severity of necessary load curtailments by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages. From a risk mitigation perspective, transmission projects provide insurance value to the system such that when contingencies, emergencies, and extreme market conditions stress the system, having a more robust grid would reduce: (1) the need to rely on high-cost measures to avoid shedding load (a production cost benefit considered in the previous section of this paper); and (2) the likelihood of load shed events, thus improving physical reliability.

Today, North American Reliability Corporation (NERC) sets the minimum requirements of transmission needed to comply with NERC reliability criteria. That is essentially the reliability planning that all transmission owners and planning authorities perform today.

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79 Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012, Section 3.3.

80 Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 77-78.

81 Midwest ISO (MISO), Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 42-44.

82 Newell, *et al.* (The Brattle Group), *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, prepared for NYISO and DPS Staff. September 15, 2015.

However, many transmission investments will generally increase the reliability of the electric power system even when meeting reliability standards is not the primary purpose of the line. Additional transmission investments made for market efficiency and public policy goals help to avoid or defer reliability upgrades that would otherwise be necessary, increase operating flexibility, reduce the risk of load shed events, and increase options for recovering from supply disruptions. This increase in reliability provides economic value by reducing the frequency, duration, and magnitude of load curtailments—or, alternatively, by reducing the planning reserve margins needed to maintain resource adequacy targets, such as a 1-day-in-10-year loss of load probability. Transmission's reduction in the required planning reserve margin accounted for a large share of the quantified transmission benefits in the MISO, SPP, and PJM studies discussed earlier in this section. These reliability benefits are not captured in production cost simulations, but can be estimated separately.

As recognized by SPP's Metrics Task Force, for example, such reliability benefits can be estimated through Monte Carlo simulations of systems under a wide range of load and outage conditions to obtain loss-of-load related reliability metrics, such as Loss of Load Hours (LOLH), Loss of Load Expectation (LOLE), and Expected Unserved Energy (EUE).[83] The reliability benefit of transmission investments can be estimated by multiplying the estimated reduction in EUE (in MWh) by the customer-weighted average Value of Lost Load (VOLL, in $/MWh). Estimates of the average VOLL can exceed $5,000 to $10,000 per curtailed MWh. The high value of lost load means that avoiding even a single reliability event that would have resulted in a blackout would be worth tens of millions to billions of dollars. As ATC notes, for example, had its Arrowhead-Weston line been built earlier, it would have reduced the impact of blackouts in the region.[84]

London Economics performed a similar study for hypothetical lines in the Western and Eastern Interconnects.[85] The study found over a single year period, under constrained system operating conditions, electric consumers are projected to save as much as $1.3 billion in PJM and $740

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[83] Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012, Section 5.2.

LOLH measures the expected number of hours in which load shedding will occur. LOLE is a metric that accounts for the expected number of days, hours, or events during which load needs to be shed due to generation shortages. And EUE is calculated as the probability-weighted MWh of load that would be unserved during loss-of-load events.

[84] American Transmission Company LLC (ATC), *Arrowhead-Weston Transmission Line: Benefits Report*, February 2009.

[85] J. Frayer, E. Wang, R. Wang, *et al.*(London Economics International, Inc.), *How Does Electric Transmission Benefit You?: Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investment*, A WIRES report, January 8, 2018.

million in MISO with the 1,300 MW Eastern Interconnect project. This is equal to savings of about $20 (in MISO) to $40 (PJM) on a typical household's annual electricity utility bill in the affected regions. As the authors note, "Although benefits of transmission investment are based on a simulation, they are nevertheless measurable and quantifiable."[86]

iii. Lower Planning Reserve Margins

When a transmission investment reduces the loss of load probabilities, system operators can reduce their resource adequacy requirements, in terms of the system-wide required planning reserve margin or the required reserve margins within individual resource adequacy zones of the region. If system operators choose to reduce resource adequacy requirements, the benefit associated with such reduction can be measured in terms of the reduced capital cost of generation. Effectively, the reduced cost would be estimated by calculating the difference in the cost of generation needed under the required reserve margins before adding the new transmission projects versus the cost of generation with the lower required reserve margins after adding the new transmission. Transmission investments tend to either reduce loss-of-load events (if the planning reserve margin is unchanged) or allow for the reduction in planning reserve margins (if holding loss-of-load events constant), but not both simultaneously.[87]

Using transmission to aggregate diverse loads allows peak electricity demand to be met with less generating capacity, as localized peaks in demand can be met using surplus generating capacity from other areas that are not experiencing peak demand at the same time. For example, the June 2021 West Coast heat wave was quantified as a 1-in-1000 year event in the Pacific Northwest,[88] yet grid operators were able to keep the lights on because the heat wave most severely affected California and the Pacific Northwest at different times, allowing each region to meet load using imports from the other region that were only possible because of sufficient transmission interconnection.

Load diversity is primarily driven by regional differences in weather and climate, and to some extent by time zone diversity across very large east-west aggregations of load. Climate diversity benefits occur in all regions, but are particularly pronounced in regions, like the Northwest and

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[86] *Id.* p 43.

[87] This is due to the overlap between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with a reduced loss-of-load probability (if the reserve margin requirement is not adjusted). Only one of these benefits is typically realized.

[88] R. Lindsey, "Preliminary analysis concludes Pacific Northwest heat wave was a 1,000-year event…hopefully," *Climate.gov*, July 20, 2021.

Southeast, that contain both winter-peaking and summer-peaking power systems. Transmission's ability to access weather diversity is also very valuable, particularly during severe weather events that tend to be at their most extreme across a relatively small footprint.[89] There are inherent diversity benefits from larger aggregations of load, as the variability in usage from even very large industrial loads is cancelled out.

The potential for transmission investments to reduce the reserve margin requirement has been recognized by a number of system operators. MISO recently estimated through LOLE reliability simulations that its MVP portfolio is expected to reduce required planning reserve margins by up to one percentage point. Such reduction in planning reserves translated into reduced generation capital investment needs ranging from $1.0 billion to $5.1 billion in present value terms, accounting for 10–30% of total MVP project costs.[90] This benefit was similarly recognized by the SPP Metrics Task Force,[91] as well as by the Public Service Commission of Wisconsin, which noted that "the addition of new transmission capacity strengthening Wisconsin's interstate connections" was one of three factors that allowed it to reduce the planning reserve margin requirements of Wisconsin utilities from 18% to 14.5%.[92]

As shown below, SPP's Value of Transmission report found its recent transmission investments provide an assumed two percent reduction in SPP's planning reserve margin, yielding 40-year net present value savings of $1.34 billion from reduced generating capacity costs, in addition to $92 million in net present value from a reduced need for generating capacity due to lower on-peak transmission losses.[93] MISO analysis shows that a lower need for capacity due to load diversity saves $1.9–$2.5 billion annually, nearly two-thirds of the RTO's total value proposition of $3.1–$3.9 billion annually.[94] Notably, this is 4–5 times larger than the roughly $500 million

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[89] M. Goggin (Grid Strategies, LLC), *Transmission Makes the Power System Resilient to Extreme Weather*, Prepared for ACORE, with Support from the Macro Grid Initiative, July 2020.

[90] Midwest ISO (MISO), *Proposed Multi Value Project Portfolio*, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 34-36.

[91] Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012, Section 5.1.

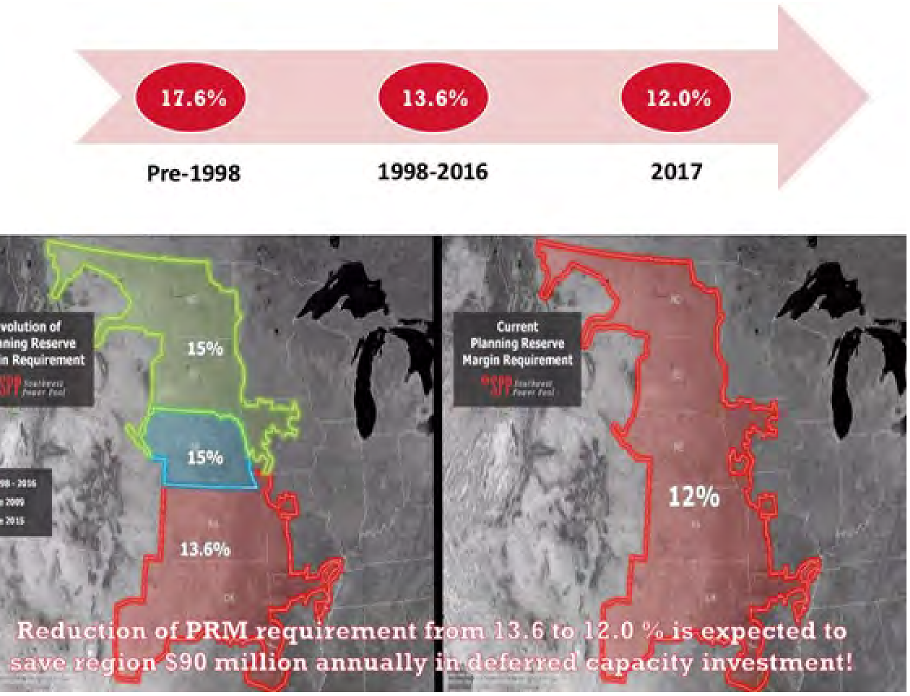
[92] Public Service Commission (PSC) of Wisconsin (WI), *Order*, re Investigation on the Commission's Own Motion to Review the 18 Percent Planning Reserve Margin Requirement, Docket 5-EI-141, PSC REF#:102692, dated October 9, 2008, received October 11, 2008, p 5. Two other changes that contributed to this decision were the introduction of the Midwest ISO as a security constrained independent dispatcher of electricity and the development of additional generation in the state.

[93] Southwest Power Pool (SPP), *The Value of Transmission*, January 26, 2016, p. 16.

[94] MISO, *MISO Value Proposition 2020*, Detailed Circulation Description, n.d., p. 22.

annual benefit from being able to make use of higher quality wind resources. Similarly, PJM finds annual savings of $1.2–$1.8 billion from regional load diversity.[95]

FIGURE 6. SPP RESERVE MARGIN EVOLUTION



Source: L. Nickell (SPP), *Resource Adequacy in SPP*, Spring 2017 Joint CREPC-WIRAB Meeting, April 2017, slides 10 and 14.

As noted above, there is additional benefit when considering severe weather and unusual grid situations. For example, this year's winter storm Uri presented a situation where a variety of generation sources in the Central region were incapacitated. MISO was able to import 13 GW from the East and deliver some of that to SPP to the West. Both of those regions largely avoided blackouts. Interestingly, the lines that were used to ship power from the East to the West were the MISO MVP lines that had originally been justified and cost allocated on the assumption of West-to-East prevailing flow, illustrating the broad reliability benefits that result from interregional transmission. ERCOT which covers most of Texas, on the other hand, had only a maximum of 0.8 GW of import capability, which limited its ability to import power, to catastrophic effect.

Another way to quantify reliability benefit is to look back to an extreme event where reliability was compromised and consider the value of hypothetical lines. In a recent example, one such

[95] PJM, *Value Proposition*, 2019, p 2.

study found that an additional GW of delivery capacity into Texas during winter storm Uri would have fully paid for itself over the course of the four-day event.[96] The same study found that an additional GW of capacity into MISO from the East would have earned $100 million during that short period of time.

Transmission also provides a reliability benefit in the form of dynamic stability. The MISO RIIA study, for example, evaluated dynamic stability needs at a range of renewable energy penetration levels.[97] At 40% renewables, MISO found weak grid issues. As synchronous generators retire, significant HVDC was added to mitigate these issues.

4. Generation Capacity Value

Transmission investments can reduce generation investment costs beyond those related to increasing the reliability benefits and reduced reserve margin requirements. Transmission upgrades can also reduce generation capacity costs in the form of: (1) lowering generation investment needs by reducing losses during peak load conditions; (2) delaying needed new generation investment by allowing for additional imports from neighboring regions with surplus capacity; and (3) providing the infrastructure that allows for the development and integration of lower-cost generation resources. Below, we discuss each of these three benefits.

i. Capacity Cost Benefits from Reduced Transmission Losses

Investments in transmission often reduce generation investment needs by reducing system-wide energy losses during peak load conditions. This benefit is in addition to the production cost savings associated with reduced energy losses. During peak hours, a reduction in energy losses will reduce the additional generation capacity needed to meet the peak load, transmission losses, and reserve margin requirements. For example, in a system with a 15% planning reserve margin, a 100 MW reduction in peak-hour losses will reduce installed generating capacity needs by 115 MW.

The economic value of reduced losses during peak system conditions can be estimated through calculating the capital cost savings associated with the reduction in installed generation requirements. These capital cost savings can be calculated by multiplying the estimated net

[96] M. Goggin (Grid Strategies, LLC), *Transmission Makes the Power System Resilient to Extreme Weather*, Prepared for ACORE, with Support from the Macro Grid Initiative, July 2020.

[97] MISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, Summary Report, February 2021.

cost of new entry (Net CONE), which is the cost of new generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource-constrained, with the reduction in installed capacity requirements.[98]

Several planning regions have estimated the capacity cost savings associated with loss reductions due to transmission investments:

- SPP's evaluation of its Priority Projects showed $92 million in net present value capacity savings from reduced losses, or 3% of total project costs.[99]
- ATC found that its Paddock-Rockdale project provided an estimated $15 million in capacity savings benefits from reduced losses, or approximately 10% of total project costs.[100]
- MISO found that its MVP portfolio reduced transmission losses during system peak by approximately 150 MW, thereby reducing the need for future generation investments with a present value benefit in the range of $111 to $396 million, offsetting 1–2% of project costs.[101]
- An analysis of potential transmission projects in the Entergy footprint showed that the projects could reduce peak-period transmission losses by 32 MW to 49 MW, offering a benefit of approximately $50 million in reduced generating investment costs, offsetting approximately 2% of total project costs.[102]

ii. Deferred Generation Capacity Investments

Transmission projects can defer generation investment needs in resource-constrained areas by increasing the transfer capabilities from neighboring regions with surplus generation capacity. For example, an analysis for ITC of potential transmission projects in the Texas portion of Entergy's service area showed that the transmission projects provide increased import

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[98] Net CONE is an estimate of the annualized fixed cost of a new natural gas plant, net of its energy and ancillary service market profits. Fixed costs include both the recovery of the initial investment as well as the ongoing fixed operating costs of a new plant. This is an estimate of the capacity price that a utility or other buyer would have to pay each year—in addition to the market price for energy—for a contract that could finance a new generating plant.

[99] Southwest Power Pool, *SPP Priority Projects Phase II Report, Rev. 1*, April 27, 2010, p 26.

[100] American Transmission Company LLC (ATC), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598), pp 4, 63.

[101] Midwest ISO (MISO), *Proposed Multi Value Project Portfolio*, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 25 and 27.

[102] Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 58-59.

capability from Louisiana and Arkansas. The imports allow surplus generating capacity in those regions to be delivered into Entergy's resource-constrained Texas service area, thereby deferring the need for building additional local generation. By doing so, existing power plants that have the option to serve the Entergy Texas service area and the rest of Texas (the ERCOT region) would be able to serve the resource-constrained ERCOT region, thereby addressing ERCOT resource adequacy challenges. The economy-wide benefit of the deferred generation investments was estimated at $320 million, about half of which was estimated to accrue to customers in Texas, with the other half of the benefit to accrue to merchant generators in Louisiana and Arkansas.[103] A similar analysis also identified approximately $400 million in resource adequacy benefits from deferred generation investments associated with a transmission project that increases the transfer capability from Entergy's Arkansas and Louisiana footprint to TVA. These overall economy-wide benefits would accrue to a combination of TVA customers, Arkansas and Louisiana merchant generators, and, through increased MISO wheeling-out revenues, Entergy and other MISO transmission customers.

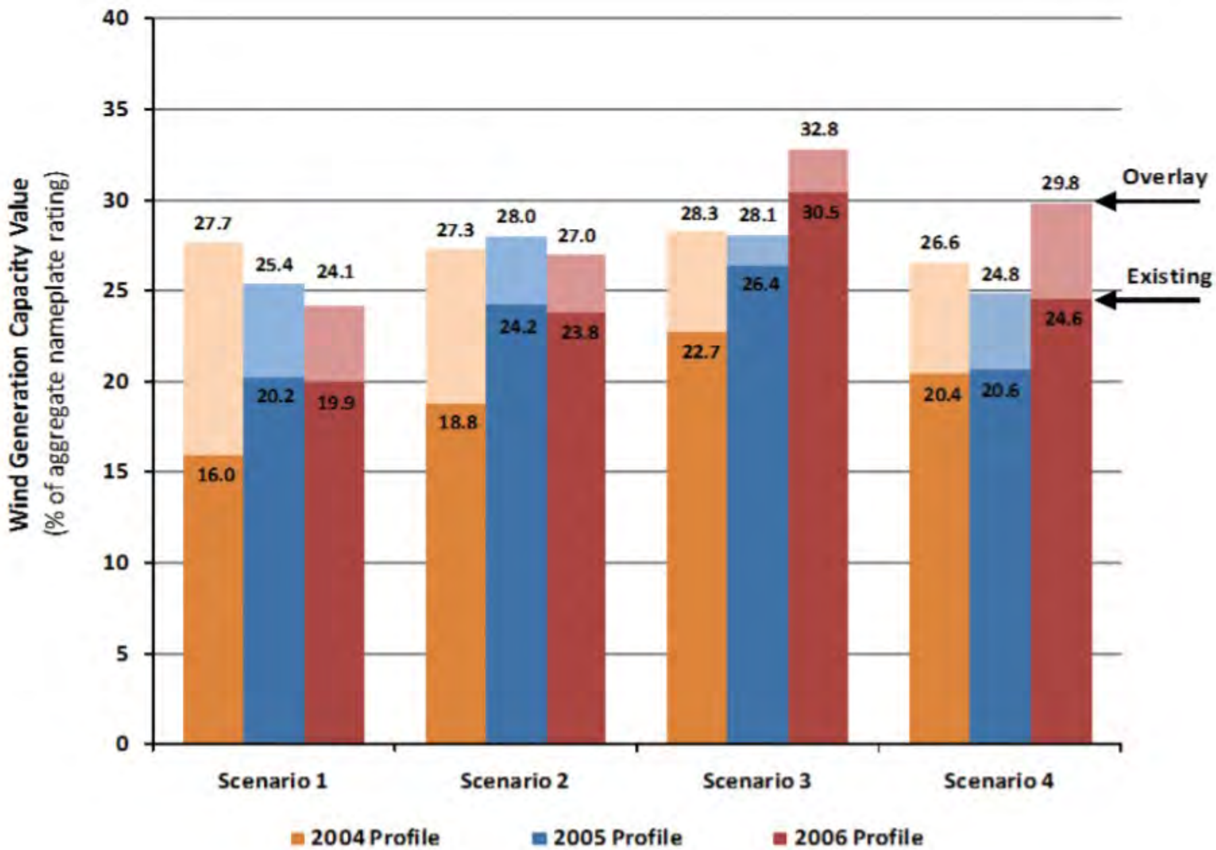
Transmission can increase the capacity value of existing resources, particularly wind and solar resources due to their geographic diversity. Higher capacity values reduce system (generation plus transmission) costs and increase net benefits. In the chart below from the Eastern Wind Integration and Transmission Study (EWITS),[104] higher wind capacity values of a few percentage points are achievable with the transmission "overlay" versus the "existing" grid. Other studies indicate even larger resource adequacy benefits from aggregating diverse renewable resources and loads.[105]

[103] *Id.*, pp 69.

[104] Enernex Corporation, *Eastern Wind Integration and Transmission Study*, prepared for The National Renewable Energy Laboratory (U.S. Department of Energy), NREL/SR-550-47078, January 2010.

[105] Energy and Environmental Economics, Inc., *Resource Adequacy in the Pacific Northwest*, March 2019.

FIGURE 7. ELCC RESULTS FOR HIGH PENETRATION SCENARIOS, WITH AND WITHOUT TRANSMISSION OVERLAYS



Source: EnerNex Corporation, *Eastern Wind Integration and Transmission Study*, prepared for The National Renewable Energy Laboratory (NREL), Revised February 2011, p 54

iii. Access to Lower-Cost Generating Resources

Some transmission investments increase access to generation resources located in low-cost areas. Generation developed in these areas may be low cost due to low permitting costs, low-cost sites on which plants can be built (*e.g.*, low-cost land and/or sites with easy access to existing infrastructure), low labor costs, low fuel costs (*e.g.*, mine mouth coal plants and natural gas plants built in locations that offer unique cost advantages), access to valuable natural resources (*e.g.*, hydroelectric or pumped storage options), locations with high-quality renewable energy resources (*e.g.*, wind, solar, geothermal, biomass), or low environmental costs (*e.g.*, low-cost carbon sequestration and storage options).

While production cost simulations can capture cost savings from fuel and variable operating costs if the different locational choices are correctly reflected in the Base and Change Case simulations, the simulations would still not capture the lower overall generation investment costs. To the extent that transmission investments provide access to locations that offer generation options with lower capital costs, these benefits need to be estimated through separate analyses. At times, to accurately capture the production cost savings of such options may require that a different generation mix is specified in the production cost simulations for the Base Case (*e.g.*, with generation located in lower-quality or higher-cost locations) and the Change Case *(e.g.*, with more generation located in higher-quality or lower-cost locations).

The benefits from transmission investments that provide improved access to lower-cost generating resources can be significant from both an economy-wide and electricity customer perspective. For example, the CAISO found that the Palo Verde-Devers transmission project was providing an additional link between Arizona and California that would have allowed California resource adequacy requirements to be met through the development of lower-cost new generation in Arizona.[106] The capital cost savings were estimated at $12 million per year from an economy-wide (*i.e.*, societal) perspective, or approximately 15% of the transmission project's cost, half of which it was assumed would accrue to California electricity customers. Similarly, ATC found that its Paddock-Rockdale transmission line enabled Wisconsin utilities to serve their growing load by building coal or IGCC generating capacity at mine-mouth coal sites in Illinois instead of building new plants in Wisconsin.[107] The analysis found that sites in Illinois offered significantly lower fuel costs (or, in the future, potentially lower carbon sequestration costs) and that the transmission investment likely reduced the total cost of serving Wisconsin load compared to new resources developed within Wisconsin.

Access to a lower-cost generation option can significantly reduce the cost of meeting public-policy requirements. For example, as discussed further under "public-policy benefits," the MISO evaluated different combinations of transmission investments and wind generation build-out options, ranging from low-quality wind locations that require less transmission investment to high-quality wind locations that require more transmission investment.[108] This analysis found that the total system costs could be significantly reduced through an optimized combination of transmission and wind generation investments that allowed a portion of total renewable energy needs to be met by wind generation in high-quality, low-cost locations. Similarly, the CREZ projects in Texas have provided new opportunities for fossil generation plants to be located away from densely populated load centers where it may be difficult to find suitable

[106] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005, pp 25-26.

[107] American Transmission Company LLC (ATC) (2007), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007, pp 54-55.

[108] Midwest ISO, *RGOS: Regional Generation Outlet Study*, November 19, 2010, p 32 and Appendix A.

sites for new generation facilities, where environmental limitations prevent the development of new plants, or where developing such generation is significantly more costly.

5. Market Benefits

Transmission expands the geographic reach of electric power markets, increasing competition, and reducing system costs. Transmission projects provide additional market benefits, both from an economy-wide and electricity customer rate perspective, by increasing competition in and the liquidity of wholesale power markets. As noted by Dr. Frank Wolak of Stanford University:

> Expansion of the transmission network typically increases the number of independent wholesale electricity suppliers that are able to compete to supply electricity at locations in the transmission network served by the upgrade...With the exception of the U.S., most countries re-structured at a time when they had significant excess transmission capacity, so the issue of how to expand the transmission network to serve the best interests of wholesale market participants has not yet become significant. In the U.S., determining how to expand the transmission network to serve the needs of wholesale market participants has been a major stumbling block to realizing the expected benefits of electricity industry re-structuring.[109]

i. Benefits of Increased Competition

Production cost simulations generally assume that generation is bid into wholesale markets at its variable operating costs. This assumption does not consider that some bids will include markups over variable costs, particularly in real-world wholesale power markets that are less than perfectly competitive. For this reason, the production cost and market price benefits associated with transmission investments could exceed the benefits quantified in cost-based simulations. This will be particularly true for transmission projects that expand access to broader geographic markets and allow more suppliers than otherwise to compete in the regional power market.[110]

[109] F. A. Wolak, "*Managing Unilateral Market Power in Electricity*," Policy Research Working Paper; No. 3691. World Bank, Washington, DC, 2005.p 8.

[110] Such effects are most pronounced during tight market conditions. Specifically, enlarging the market by transmission lines that increase transfer capability across multiple markets can decrease suppliers' market power and reduce overall market concentration. The overall magnitude of benefits from increased competition

A lack of transmission to ensure competitive wholesale markets can be particularly costly to customers. For example, the Chair of the CAISO's Market Surveillance Committee estimated that if significant additional transmission capacity had been available during the California energy crisis from June 2000 to June 2001, electricity customer costs would have been reduced by up to $30 billion over the 12-month period during which the crisis occurred.[111] More recently, ISO New England noted that increased transmission capacity into constrained areas such as Connecticut and Boston have significantly reduced congestion, "thereby significantly reducing the likelihood that resources in the submarkets could exercise market power."[112]

Given the experience during the California Power Crisis, the ability of transmission investment to increase competition in wholesale power markets has been considered explicitly in the CAISO's review of several proposed new transmission projects. For example, in its evaluation of the proposed Palo Verde-Devers transmission project, the CAISO noted that the "line will significantly augment the transmission infrastructure that is critical to support competitive wholesale energy markets for California consumers" and estimated that increased competition would provide $28 million in additional annual consumer and "modified societal" benefits, offsetting approximately 40% of the annualized project costs.[113] Similarly, in its evaluation of the Path 26 Upgrade transmission projects, the CAISO estimated the expected value of competitiveness benefits could offset up to 50 to 100% of the project costs, with a range depending on project costs and assumed future market conditions.[114] A similar analysis was performed for ATC's Paddock-Rockdale line, estimating that the benefits of increased competition would offset between 10 to 40% of the project costs, depending on assumed market structure and supplier behavior.[115]

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can range widely, from a small fraction to multiples of the simulated production cost savings, depending on: (1) the portion of load served by cost-of-service generation; (2) the generation mix and load obligations of market-based suppliers; and (3) the extent and effectiveness by which RTOs' market power mitigation rules yield competitive outcomes.

111 California ISO, *Transmission Economic Assessment Methodology (TEAM)*, June 2004, pp ES-9.

112 Federal Energy Regulatory Commission, *2011 Performance Metrics for Independent System Operators and Regional Transmission Organizations*, A Report to Congress in Response to Recommendations of the United States Government Accountability Office, April 7, 2011.

113 California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005, pp 18 and 27. Under the "modified societal perspective" of the CAISO TEAM approach, producer benefits include net generator profits from competitive market conditions only. This modified societal perspective excludes generator profits due to uncompetitive market conditions.

114 California ISO, *Transmission Economic Assessment Methodology (TEAM)*, June 2004.

115 Pfeifenberger, Direct Testimony on behalf of American Transmission Company, before the Public Service Commission of Wisconsin, Docket 137-CE-149, January 17, 2008; and American Transmission Company LLC

ii. Benefits of Increased Market Liquidity

Limited liquidity in the wholesale electricity markets imposes higher transaction costs and price uncertainty on both buyers and sellers. Transmission expansions can increase market liquidity by increasing the number of buyers and sellers able to transact with each other, which in turn will reduce the transaction costs (*e.g.*, bid-ask spreads) of bilateral transactions, increase pricing transparency, increase the efficiency of risk management, improve contracting, and provide better clarity for long-term planning and investment decisions.

Estimating the value of increased liquidity is challenging, but the benefits can be sizeable in terms of increased market efficiency and thus reduced economy-wide costs. For example, the bid-ask spreads for bilateral trades at less liquid hubs have been found to be between $0.50 to $1.50/MWh higher than the bid-ask spreads at more liquid hubs.[116] At transaction volumes ranging from less than 10 million to over 100 million MWh per quarter at each of more than 30 electricity trading hubs in the U.S., even a $0.10/MWh reduction of bid-ask spreads due to a transmission-investment-related increase in market liquidity would save $4 million to $40 million per year for a single trading hub, which would amount to a transactions cost savings of approximately $500 million annually on a nation-wide basis.

6. Environmental Benefits

Depending on the effects of transmission expansions on the overall generation dispatch, some projects can reduce harmful emissions (*e.g.,* SO_2, NO_x, particulates, mercury, and greenhouse gases) by avoiding the dispatch of high-emissions generation resources. The benefits of reduced emissions with a market pricing mechanism are largely calculated in production cost simulations for pollutants with emissions prices such as SO_2 and NO_x. However, for pollutants that do not have a pricing mechanism yet, such as CO_2 in some regions, production cost simulations do not directly capture such environmental benefits unless specific assumptions about future emissions costs are incorporated into the simulations.

Not every proposed transmission project will necessarily provide environmental benefits. Some transmission investments can be environmentally neutral or even displace clean but more

(ATC), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598C), pp 44-47.

116 Pfeifenberger, Oral Testimony on behalf of Southern California Edison Company re economic impacts of the proposed Devers-Palo Verde No. 2 transmission line, before the Arizona Power Plant and Transmission Line Siting Committee, Docket No. L-00000A-06-0295-00130, Case No. 130, September and October, 2006

expensive generation (*e.g.*, displacing natural gas-fired generation when gas prices are high) with lower-cost but higher-emissions generation. In some instances, a reduction in local emissions may be valuable (*e.g.*, reduced ozone and particulates) but not result in reduced regional (or national) emissions due to a cap and trade program that already limits the total of allowed emissions in the region. Nevertheless, even if specific transmission projects do not reduce the overall emissions, they may affect the costs of emissions allowances which in turn could affect the cost of delivered power to customers.

As more and more transmission projects are proposed to interconnect and better integrate renewable resources, some project proponents have quantified specific emissions reductions associated with those projects. For example, Southern California Edison estimated that the proposed Palo Verde-Devers No. 2 project would reduce annual NO_x emissions in WECC by approximately 390 tons and CO_2 emissions by about 360,000 tons per year. These emissions reductions were estimated to be worth in the range of $1 million to $10 million per year.[117] Similarly, an analysis of a portfolio of transmission projects in the Entergy service area estimated that the congestion and RMR relief provided by the projects would eliminate approximately one million tons of CO_2 emissions from fossil-fuel generators every year.[118] That estimated emissions reduction is equivalent to removing the annual CO_2 emissions from over 200,000 cars.

7. Public Policy Benefits

Some transmission projects can help regions reduce the cost of reaching public-policy goals, such as meeting the region's renewable energy targets by facilitating the integration of lower-cost renewable resources located in remote areas; while enlarging markets by interconnecting regions can also decrease a region's cost of balancing intermittent renewable resources.

As an illustration of these savings, transmission investments that allow the integration of wind generation in locations with a 40% average annual capacity factor can reduce the investment cost of wind generation by *one quarter* for the same amount of renewable energy produced compared to the investment costs of wind generation in locations with a 30% capacity factor.[119]

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[117] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005, pp 26.

[118] Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 83.

[119] Burns & McDonnell Engineering Company, Inc., *Wind Energy Transmission Economics Assessment*, prepared for WPPI Energy, Project No. 55056, March 2010, pp 1–2, Figure 2.

Access to higher quality wind resources will reduce both economy-wide and electricity customer costs if the higher-quality wind resources can be integrated with additional transmission investment of less than the benefit, estimated to be $500 to $700 per kW of installed wind capacity.

As noted earlier, the MISO has assessed this benefit by evaluating different combinations of transmission investments and wind generation build-out options. The MISO analysis shows that the total cost of wind plants and transmission can be reduced from over $110 billion for either all local or all regional wind resources to $80 billion for a combination of local and regional wind development. The savings achieved from an optimized combination of local and regional wind and transmission investment would be over $30 billion.[120] These cost savings could be achieved by increasing the transmission investment per kW of wind generation from $422/kW in the all-local-wind case to $597/kW in the lowest-total-cost case.

A similar analysis was carried over into MISO's analysis of its portfolio of multi-value projects, which were targeted to help the Midwestern states meet their renewable energy goals. By facilitating the integration of high-quality wind resources, MISO's initial analysis found that its MVP portfolio reduced the present value of wind generation investments by between $1.4 billion and $2.5 billion, offsetting approximately 15% of the transmission project costs.[121] Similarly, ATC found that its Arrowhead-Weston transmission project has the capability to deliver hydro resources from Canada and wind power from the Dakotas and interconnect local renewable generation to help meet Wisconsin's RPS requirement.[122]

Additional transmission investment can help reduce the cost associated with balancing intermittent resources. Interconnecting regions and expanding the grid allow a region to simultaneously access a more diverse set of intermittent resources than smaller systems. Such diversity would reduce the cost of balancing the system due to the "self-balancing" effect of generation output diversity and the larger pool of conventional resources that are available to compensate for the variable and uncertain nature of intermittent resources. The associated savings can be estimated in terms of the reduction of the balancing resources required (which is a fixed cost reduction) and a more efficient unit-commitment and system operation (which includes a variable cost reduction). If less generating capacity from conventional generation is

[120] Midwest ISO (MISO), *RGOS: Regional Generation Outlet Study*, November 19, 2010, p 32 and Appendix A.

[121] Midwest ISO (MISO), *Proposed Multi Value Project Portfolio*, Technical Study Task Force and Business Case Workshop, August 22, 2011, pp 25 and 38-41.

[122] American Transmission Company LLC (ATC), *Arrowhead-Weston Transmission Line: Benefits Report*, February 2009, p 7.

needed, the reduction in capacity costs can be estimated using the Net Cost of New Entry. For the potential reduction in the operational costs associated with balancing renewable resources, if we assume that the renewable generation balancing benefit of an expanded regional grid reduces balancing costs by only $1/MWh of wind generation, the annual savings associated with 10,000 MW of wind generation at 30% capacity factor would exceed $25 million.

To summarize, even though making significant transmission investments to gain access to remotely located renewable resources seems to increase the cost of delivering renewable generation, the savings associated with reducing the renewable generation costs (by obtaining access to high quality renewable resources), reducing the system balancing costs, and achieving other reliability and economic benefits can exceed the incremental cost of those transmission projects. In such cases, despite the fact that both transmission and retail electricity rates may increase, the transmission investment can reduce the overall cost of satisfying public policy goals.[123] While this rationale will not apply to every public-policy-driven transmission project, it is instructive to consider these benefits and, if needed, estimate all potential benefits when evaluating large regional transmission investments.

8. Other Benefits

Some transmission investments can create additional benefits that are very specific to the particular set of projects. These benefits may include improved storm hardening and wild-fire resilience, increased load-serving capability, synergies with future transmission projects, the option value of large transmission facilities to improve future utilization of available transmission corridors, fuel diversity benefits, increased resource planning and system operational flexibility, increased wheeling revenues, and the creation of additional physical or financial transmission rights to improve congestion hedging opportunities. Please see Appendix C for more details.

b. Multi-Value Planning Examples

As Table 4 has summarized in the beginning of this section, significant experience with multi-value transmission planning already exists within SPP, MISO, CAISO, and NYISO.

[123] In developing public policy goals, state or federal policy makers may have identified benefits inherent in the policies that are not necessarily economic or immediate. For the evaluation of public policy transmission projects, however, the objective is not to assess the benefits and costs of the public policy goal, but the extent to which transmission investments can reduce the overall cost of meeting the public policy goal.

1. SPP Integrated Transmission Planning (ITP), Metrics Task Force (MTF), and Regional Cost Allocation Review (RCAR)

The ITP efforts by SPP have moved toward examining a range of transmission-related benefits in its transmission project evaluations, which included: production cost savings, reduced transmission losses, wind revenue impacts, natural gas market benefits, reliability benefits, and economic stimulus benefits of transmission and wind generation construction. Along with the benefits for which monetary values were estimated, the SPP's Economic Studies Working Group agreed that a number of transmission benefits that require further analysis include, enabling future markets, storm hardening, Improving operating practices/maintenance schedules, lowering reliability margins, improving dynamic performance and grid stability during extreme events, societal economic benefits.

Later, to support cost allocation efforts, SPP's MTF further expanded SPP's frameworks for estimating additional transmission benefits to include the value of reduced energy losses, the mitigation of transmission outage-related costs, the reduced cost of extreme events, the value of reduced planning reserve margins or the loss of load probabilities, the increased wheeling through and out of revenues (which can offset a portion of transmission costs that need to be recovered from SPP's internal loads), and the value of meeting public-policy goals. SPP's MTF also recommended further evaluation of methodologies to estimate the value of other benefits such as the mitigation of costs associated with weather uncertainty and the reduced cycling of baseload generating units.

SPP's Regional Cost Allocation Review has further expanded the scope of benefits to include avoided or delayed reliability projects, capacity savings due to reduced on-peak transmission losses, transmission outage cost savings, and marginal energy loss benefits.[124]

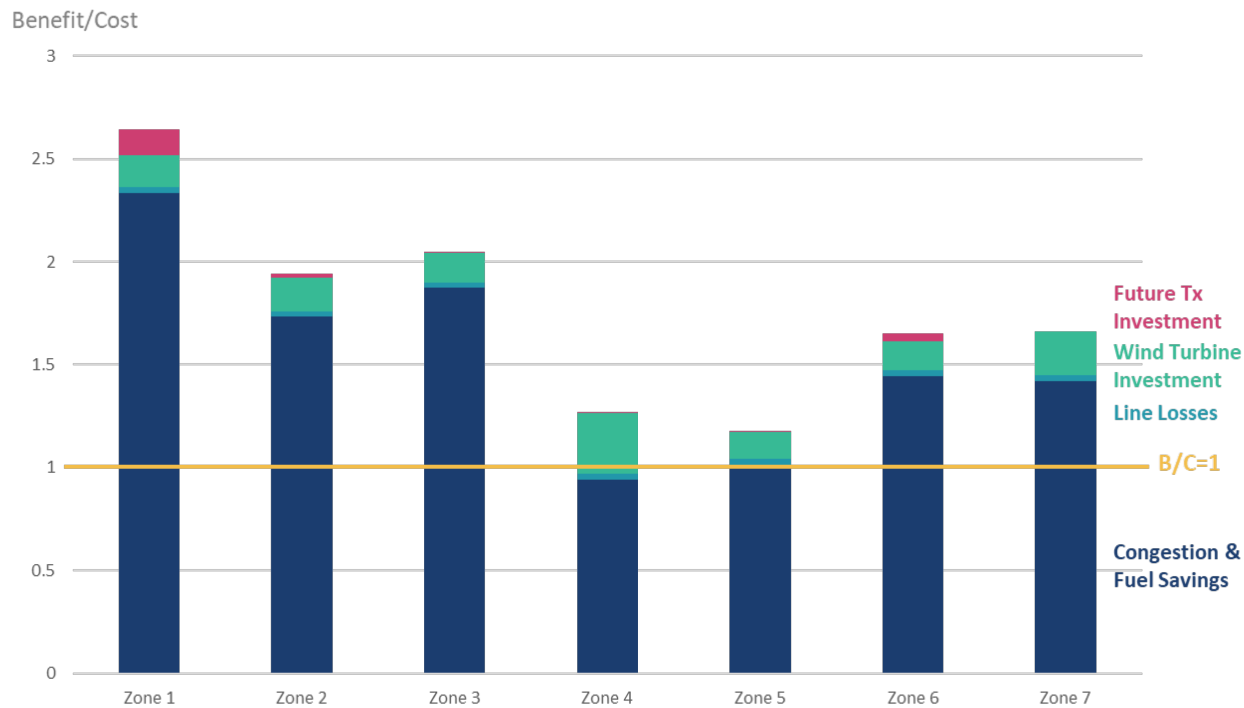
2. MISO Multi Value Projects (MVP)

MISO's evaluation and development of its MVP portfolio is a good example of a pro-active planning process that considered multiple benefits. The quantified benefits included:
(1) congestion and fuel cost savings; (2) reduced costs of operating reserves; (3) reduced planning reserve margin requirements; (4) deferred generation investment needs due to

[124] Southwest Power Pool (SPP), *Regional Cost Allocation Review (RCAR II)*, July 11, 2016.

reduced on-peak transmission losses; (5) reduced renewable investment costs to meet public policy goals; and (6) reduced other future transmission investments. When approving projects in 2011, the MISO board of directors based their approval on the need to support a variety of state energy policies, to maintain reliability, and to obtain economic benefits in excess of costs. The $6.6 billion worth of MVP projects that resulted are now estimated to provide economic net-benefits of $7.3 to $39 billion over the next 20 to 40 years, which (as shown in Figure 8) produces net benefits in each of MISO's planning zones.[125]

FIGURE 8. MISO MVP BENEFITS BY ZONE



Source: Low range 20 year NPV from MISO, MTEP19 MVP Limited Review Report, 2019.

3. New York Public Policy Transmission Planning Process

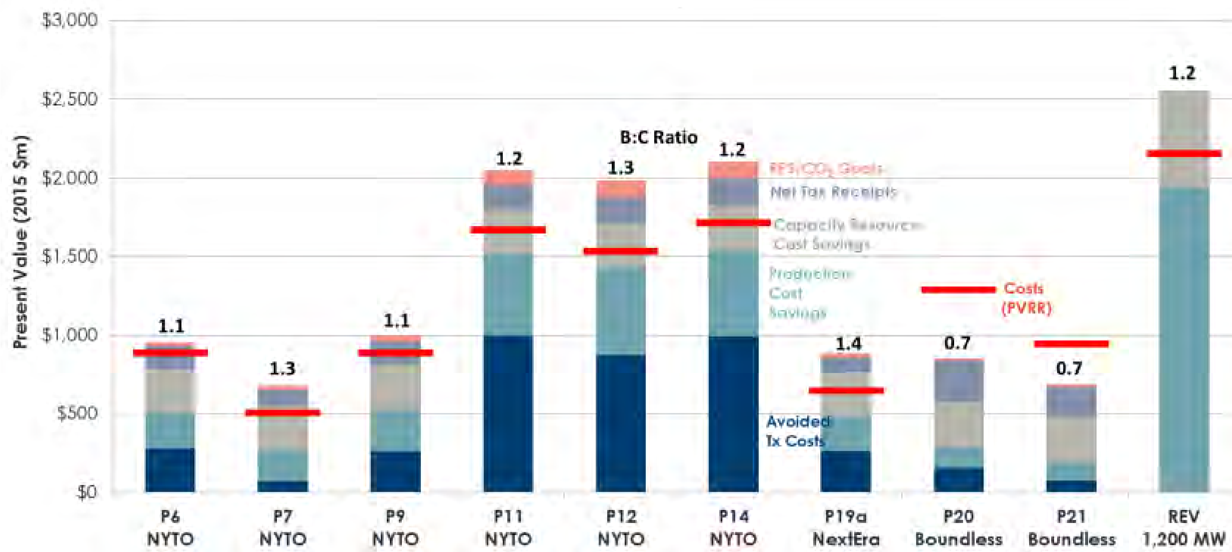
In New York, NYISO implemented a multi-value "public policy" transmission planning process after the New York Public Service Commission (PSC) mandated that approach in 2015. Prior, the existing approach for identifying "economic" projects through the NYISO Congestion Assessment and Resource Integration Study (CARIS) failed to identify regional projects to be built due to its limited scope of benefits considered: it focused solely on adjusted production

[125] MISO, *MTEP19 MVP Limited Review Report*, 2019.

cost savings over a 10-year period.[126] The PPTPP starts with the suggestions of public policy transmission needs (PPTN) by market participations. After the PSC approves specific needs, the NYISO solicits solutions from market participations, which are then being evaluated based on a multi-value framework that recognizes and quantifies the broad set of benefits that the proposed solutions may provide.

Considering the broader range of benefits that transmission provides, and that a large portion of total benefits are the avoided costs of not having to upgrade the aging infrastructure later (due to facilities nearing the end of their useful life), seven portfolios of initially proposed projects and the Reforming the Energy Vision (REV) resources were found to provide net societal benefits as (see Figure 9) and two upgrades were ultimately approved.

FIGURE 9. SUMMARY OF NEW YORK SOCIETAL BENEFIT-COST ANALYSIS



Source: Newell, *et al.* (The Brattle Group), Benefit-Cost Analysis of Proposed New York AC Trans9ission Upgrades, prepared for NYISO and DPS Staff. September 15, 2015.

[126] Newell, *et al.* (The Brattle Group), *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, prepared for NYISO and DPS Staff. September 15, 2015.

4. CAISO Transmission Economic Assessment Methodology (TEAM)

CAISO has occasionally utilized its TEAM approach in its transmission planning effort, which considers multiple benefits.[127] When initially evaluating CAISO's Palo Verde-Devers 2 (PVD2) line, the California Public Utility Commission (CPUC) relied on results from the TEAM approach.[128] Quantified benefits included production cost benefits, operational benefits, generation investment cost savings, reduced losses, competitiveness benefits, and emissions benefits.[129] This proved critical, as the PVD2 project benefits exceeded project costs by more than 50%, but only if multiple benefits were quantified (Figure 10). Thus, traditional planning approaches would have rejected the PVD2 transmission investment despite the fact that the CAISO's more comprehensive analysis shows it offered overall costs savings in excess of the project costs including significant risk mitigation benefits. In contrast, the CAISO TEAM analysis of PVD2 went beyond a base-case production cost analysis to identify a much broader range of transmission-related benefits and estimated the value associated with them more comprehensively than what most economic analyses of transmission projects do today.

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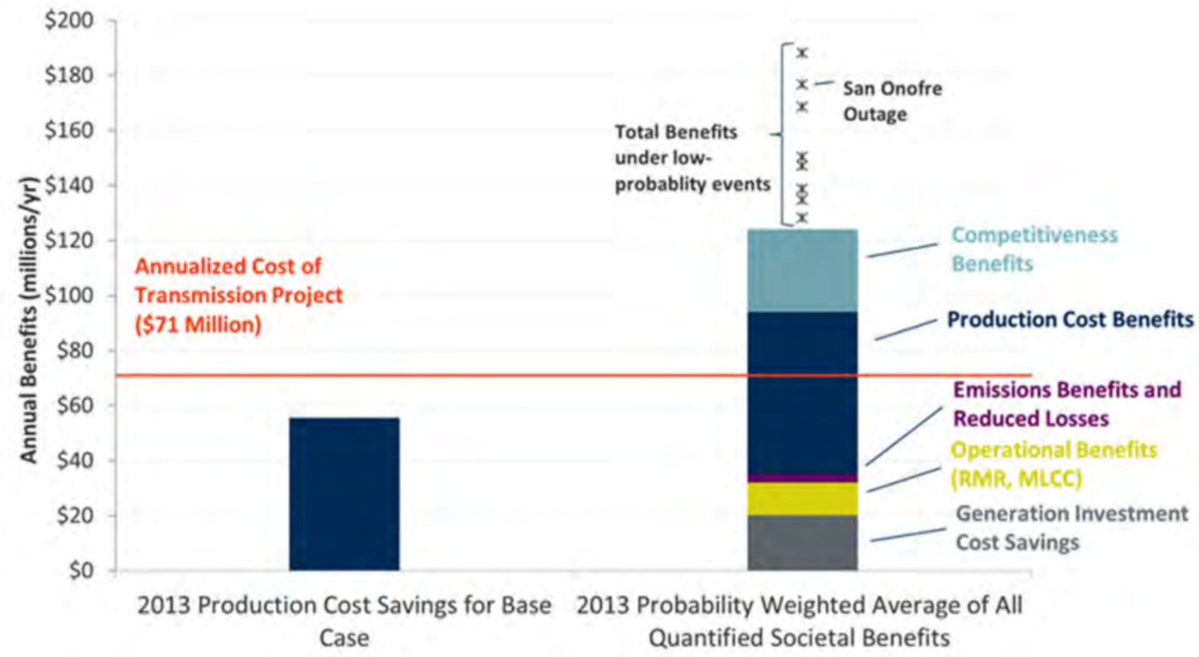
[127] CAISO, Transmission Economic Assessment Methodology (TEAM), June 2004.

[128] CAISO, Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2), February 24, 2005.

[129] The CAISO identified a number of project-related benefits that were not quantified for the purpose of comparing benefits and costs. These unquantified benefits included: increased operational flexibility (providing the system operator with more options for responding to transmission and generation outages); facilitation of the retirement of aging power plants; encouraging fuel diversity; improved reserve sharing; and increased voltage support.

FIGURE 10. PVD2 ANNUAL BENEFITS IN COMPARISON TO COSTS



However, despite its experience with TEAM, most of CAISO's recent planning efforts focus solely on reliability needs or impacts on wholesale market prices, congestion, and production costs. We are aware of only two recent transmission projects—the Harry Allen to Eldorado 500 kV line and the Delaney to Colorado River 500 kV line (the successor of the PVD2 project first evaluated in 2004)—which the CAISO justified and approved based on quantification of multiple economic benefits.

3. Address Uncertainties and High-Stress Conditions Explicitly through Scenario-Based Planning

While proactive planning improves planning beyond considering status-quo needs or reliability needs (including those created by generation interconnection requests), it may still only consider a single "base case" scenario (as was done in the PJM offshore wind study). Scenario-based planning takes the planning process a step further by explicitly recognizing that planning for the future requires dealing with uncertainty. Because the industry, its market conditions, and even its regulations are invariably uncertain, today's conditions or current trends should not be the primary scenario, let alone the exclusive basis, for how the industry plans transmission facilities in the next decade or two for service 20, 30, or 40 years in the future. This type of scenario-based long-term planning is widely used by other industries, such as the oil and gas, utility planning, and many other industries.[130] Such scenario-based planning using existing tools and proven methods can be deployed to identify robust solutions that are beneficial across a range of scenarios.

Reactive planning to meet near-term reliability or interconnection needs often completely ignores uncertainty, as other future needs are not even considered in the planning effort. Uncertainties about future regulations, industry structure, or generation technology (and associated investments and retirements) can substantially affect the need and size of future transmission projects. A well-planned, flexible transmission system can insure against the risks of high-cost outcomes in the future ("insurance value"). Because future outcomes are highly uncertain, it is important to plan in such a way to minimise "regret" in all plausible scenarios and consider "option value." Without considering a range of plausible scenarios, planning procedures do not address the risk of leaving customers with few options beyond a cost-ineffective set of infrastructure that results in very high system-wide costs. Factors to consider in scenario-based planning include (but not limited to):

- Public Policy Mandates and Goals
- Electrification and Efficiency Adoption
- Economic Growth
- Commodity Costs
- Technology Costs & Availability
- Generation Type and Location
- Future Weather/Climate Conditions, including Extreme Weather Frequency
- Resource Adequacy and Reserve Needs
- Customer Preferences

Finding efficient solutions under conditions of uncertainty is a well-established field of economic policy. One methodological approach relies on the concept of "expected value," which is a calculation of the (probability-weighted) average of multiple potential outcomes in the future. In transmission planning, this methodology is very important because transmission can be extremely valuable in scenarios that can occur in reality but are often not considered in current planning processes' analyses. For example during winter storm Uri in February 2021, additional transmission lines into Texas would have provided so many benefits that they would

[130] Royal Dutch Shell plc, *New Lens Scenarios: A Shift in Perspective for a World in Transition*, March 2013; Wilkinson, Angela and Roland Kupers, "*Living in the Futures*," Harvard Business Review, May 2013.

have fully paid for themselves in 2.5 days, and an additional Gigawatt of transmission capacity into MISO would have provided $100 million in benefit over the event.[131] Prospectively, such scenarios can be considered with proper weighting for the likelihood or probability of such events. For example, even if only one such extreme event can be expected in any decade, the probability weighted annual average would be 1/10th of the benefits the transmission is estimated to provide. However, the distribution of possible outcomes needs to be considered beyond the probability-weighted expected value, since two projects with the same expected value may have vastly different risk profile—with one project significantly reducing the risk of very high cost outcomes relative to the other project.

A frequently voiced concern is that effective transmission planning is not possible until key uncertainties are resolved. This concern has effectively stalled regional and interregional planning processes. However, delaying long-term planning because the future is uncertain will necessarily limit transmission upgrades and miss opportunities to capture higher values through investments that could address longer-term needs more cost effectively. While objectively determining a reasonable set of scenarios that captures possible future market conditions requires careful considerations, it will be much more efficient to do that than ignore uncertainties all together or wait for uncertainties to resolve themselves.

Evaluating long-term uncertainties by defining various distinctive (and equally plausible) “futures” is important given the long useful life of new transmission facilities that can exceed four or five decades. Long-term uncertainties around fuel price trends, locations, and size of future load and generation patterns, economic and public policy-driven changes to future market rules or industry structure, and technological changes can substantially affect the need and size of future transmission projects. Results from scenario-based analyses of these long-term uncertainties can then be used to: (1) identify “least-regrets” projects that mitigate the risk of high-cost outcomes and whose value would be robust across most futures;[132] and (2) identify or evaluate possible project modifications (such as building a single circuit line on double circuit towers) in order to create valuable options that can be exercised in the future depending on how the industry actually evolves. In other words, the range in long-term values

[131] M. Goggin (Grid Strategies, LLC), *Transmission Makes the Power System Resilient to Extreme Weather*, Prepared for ACORE, with Support from the Macro Grid Initiative, July 2020.

[132] For least regret’s planning to deliver robust planning choices, it is important to consider how transmission projects can reduce the risk that some future outcomes may lead to either (a) the regret that the cost of building the project significantly exceeds the project’s benefits, or (b) the regret that not building the project results in very-high-cost outcomes that far exceed the project’s cost. Reducing the cost of both types of regrettable outcomes is necessary to reduce the project’s overall risk in light of an uncertain future.

of economic transmission projects under the various scenarios can be used both to assess the robustness of a project's cost effectiveness and to help identify project modifications that increase the flexibility of the system to adapt to changing market conditions.

For example, a scenario-based long-term transmission planning study was first presented to the Public Service Commission of Wisconsin by American Transmission Company (ATC) in 2007.[133] In its Planning Analysis of the Paddock-Rockdale Project, ATC evaluated the benefit that the project would provide under seven plausible futures. That ATC study, which evaluated a wide range of transmission-related benefits, found that while the 40-year present value of the project's customer benefits fell short of the project's revenue requirement in the "Slow Growth" future, the present value of the potential benefits substantially exceeded the costs in other futures scenarios analyzed. The other scenarios also showed that not investing in the project could leave customers as much as $700 million worse off. Overall, the Paddock-Rockdale analysis showed that understanding the potential impact of projects across plausible futures is necessary for transmission planning under uncertainties and for assessing the long-term risk mitigation benefit of a more robust, more flexible transmission grid.

In 2014, ERCOT improved their stakeholder-driven long-term transmission planning process by applying a scenario-based planning framework to identify the key trends, uncertainties, and drivers of long-term transmission needs in ERCOT.[134] ERCOT converted the detailed scenario descriptions (developed jointly by stakeholders) into transmission planning assumptions, which differed in their projections for load growth, environmental regulations, generation technology options/costs, oil and gas prices, transmission regulations and policies, resource adequacy, end-use markets, and weather and water conditions. Following that, ERCOT performed initial planning analyses for ten scenarios—including projections of likely locations and magnitudes of generation investments and retirements—and identified four scenarios that covered the most distinct range of possible futures to carry forward for detailed long-term system modeling analyses.

MISO's MVP planning effort, noted for its proactive planning in the prior section, also utilized a scenario-based approach to identify the selected projects. In MISO's original RGOS process, three scenarios were considered and the projects that yielded beneficial outcomes in all scenarios eventually went on to become the MVP projects.

[133] Before the Public Service Commission of Wisconsin, Docket 137-CE-149, Planning Analysis of the Paddock-Rockdale Project, American Transmission Company, April 5, 2007.

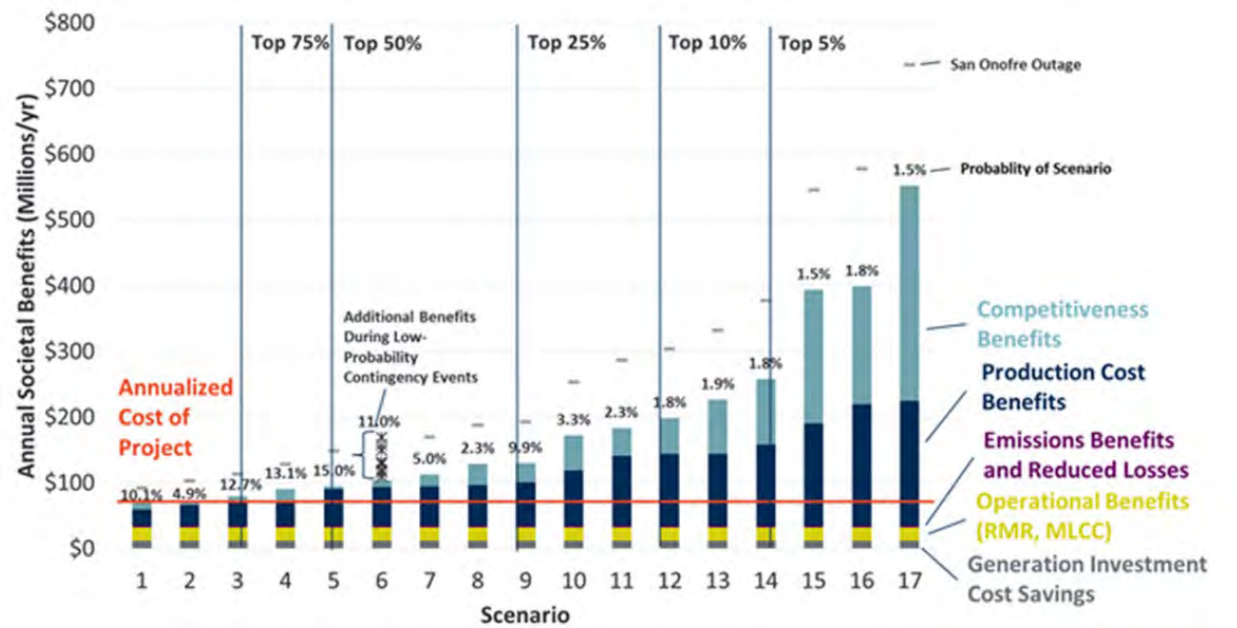
[134] ERCOT, *2014 Long-Term System Assessment for the ERCOT Region*, December, 2014; Chang, Pfiefenberger and Hagerty (The Brattle Group), *Stakeholder-Driven Scenario Development for the ERCOT 2014 Long-Term System Assessment*, September 30, 2014.

California's planners similarly have applied scenario-based approaches in the past. CAISO's 2004 analysis of its Palo Verde to Devers (PVD2) project considered seventeen plausible scenarios and a number of long-term contingencies (which could happen in any of the scenarios) to show that base-case results still significantly understated the overall cost-reductions and risk mitigation offered by the project.[135] Based on the range of scenarios, CAISO showed that the probability-weighted average of the project benefits exceeded the savings estimated in the base-case scenario, which did not have benefits that exceeded costs (Figure 11). Thus, most economic transmission planning processes that focus solely on such base-case benefit and cost comparisons would have rejected the PVD2 transmission project because the quantified benefits do not appear to justify the project's costs.

The CAISO analysis found that if certain low-probability events (such as a long-term outage of the San Onofre nuclear plant) were considered, the proposed transmission investment could avoid up to $70 million of additional cost per year, significantly increasing the projected value of the project. *Ex post*, we now know that one of such high-impact, low-probability events turned out to be quite real: the San Onofre nuclear plant has been out of service since early 2012 and has now been closed permanently. Such "hard-to-anticipate" events are very likely to occur over the long life of transmission facilities. Ignoring that possibility understates the value of new transmission, particularly those projects that reduce exposure to costly events.

[135] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005.

FIGURE 11. RANGE OF PROJECTED SOCIETAL BENEFITS OF PVD2 PROJECT COMPARED TO PROJECT COSTS



Source: Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015.

Thus, while proactive planning already offers a significant improvement over current planning processes, it may understate project benefits if only a “base case” is evaluated. This risks projects not moving forward due to a lack of understanding of possible benefits in an uncertain future. In addition, the lack of scenarios can result in an inadequate understanding of the potentially high costs of not pursing the project. Recognizing the uncertainties about the future with the use of scenario-based planning can improve current transmission planning processes that are focused solely (or mostly) on a “base case” that reflects the status quo or current trends.

One scenario that is increasingly more likely to be reflective of future market conditions is one with stringent state or federal clean-energy regulation. Over the last decade, numerous and ambitious state clean energy standards have already changed system needs. It is possible, if not likely, that there will be additional significant state or federal clean energy or climate policies. Even if such policies are outside the confines of electricity regulation, they impact the generation mix, power flows, and the value of transmission that has to be expected. Even if some such policies are not yet implemented, it is prudent to consider the possibility of such future policies through scenario-based planning (along with scenarios that envision a future that may not impose such policies). Of course, once such policies are passed they should be considered proactively in “base case” planning scenarios and transmission plans.

A London Economics report described scenario planning this way:

> Utilizing scenario analysis can help decision makers to better understand and quantify the expected range of benefits over the long term. Scenario analysis can capture the impact of uncertainty or the magnitude and longevity of benefits, and even identify beneficiaries that were not anticipated under a "base case" or most likely forecast. In some cases, scenario analysis can also show that benefits may arise irrespective to future market outcomes.[136]

A Brattle Group report for WIRES contains a more detailed discussion on the use of scenarios (to address long-term future uncertainties) and sensitivities (to address short term uncertainties that can happen in each scenario of future market conditions)[137]

4. Use Portfolios of Transmission Projects

Planning a portfolio of synergistic transmission projects can reduce electricity costs by identifying solutions that are more valuable than the sum of the individual projects' value. A synergistic portfolio of projects might also consider both storage and other technologies. Studies that co-optimize storage and transmission tend to find that they are complementary components and not substitutes. There is usually a "sweet spot" where the optimal amount of both storage and transmission lead to the lowest system cost.

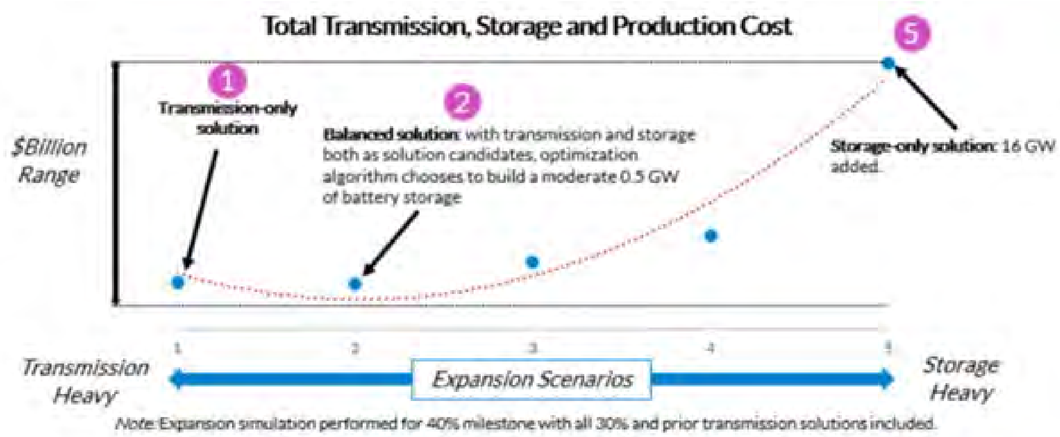
For example, MISO evaluated both transmission and storage in its RIIA study.[138] In this study, if the model was allowed to optimize transmission and storage it selected 0.5 GW of storage plus significant additional transmission. If it was allowed to build only storage without additional transmission, the model selected 16 GW at a much higher total system-wide cost. The combined transmission and storage solution achieved a lower system-wide cost than either transmission or storage alone. The graph below shows this "sweet spot" of an optimal combination of transmission and storage.

[136] J. Frayer, E. Wang, R. Wang, *et al.*(London Economics International, Inc.), *How Does Electric Transmission Benefit You?: Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investment*, A WIRES report, January 8, 2018, p 46.

[137] Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015, pp 9–19 and Appendix B.

[138] MISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, Summer Report, February 2021.

FIGURE 12. COSTS FOR SCENARIOS VARYING IN TRANSMISSION AND STORAGE EXPANSION



Source: MISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, Summer Report, February 2021, p 93.

Similarly, portfolio-based planning can consider and co-optimize transmission and distributed energy resources (DERs). Studies that co-optimize DERs, transmission, and small and large generation sources can achieve a lower system-wide cost than those that focus on one over the others. Notably, such studies (even with high levels of DERs) still find transmission system expansion to be very valuable. In fact, in one recent study that considered a high DER scenario, 10 million more MW-miles more transmission is required to minimize system-wide costs due to the complementarity (not substitutability) of DERs and transmission.[139]

For the purpose of cost allocation, however, considering even larger portfolios offers additional advantages—it will reduce the contentiousness of cost allocations since the benefits of larger transmission portfolios will be more evenly distributed and stable over time.[140] Such portfolio-wide cost allocation approach is widely used for other infrastructure, including roads or electric distribution systems.

Because the benefits of a portfolio of transmission projects will generally be more evenly distributed and stable than for a single project, portfolio-based cost recovery allows for less complex (and contentious) cost allocation approaches while still ensuring that the sum of costs allocated is roughly commensurate with the sum of benefits received. While the SPP highway-byway and MISO MVP examples demonstrate that the benefits of portfolio of projects are

[139] C. T. M. Clack, A. Choukulkar, B. Coté, and S. A. McKee (Vibrant Clean Energy LLC), *Why Local Solar For All Costs Less: A New Roadmap for the Lowest Cost Grid*, Technical Report, December 1, 2020.

[140] See, for example, *Transmission Cost Allocation: Principles, Methodologies, and Recommendations*, presentation to the OMS Cost Allocation Principles Committee, November 16, 2020.

roughly commensurate with allocated costs, the MVP cost allocation approach would not meet that standard for individual ITP and MVP projects.[141]

5. Jointly Plan Neighboring Interregional Systems

Improving interregional transmission planning is the subject of several other reports.[142] We address this topic here only briefly. Interregional transmission can provide large economic, reliability, and public policy benefits that can lower electricity costs, as already discussed for several examples above. Similar to regional transmission planning, however, interregional planning also suffers from lack of pro-active, multi-value, and scenario-based analysis.

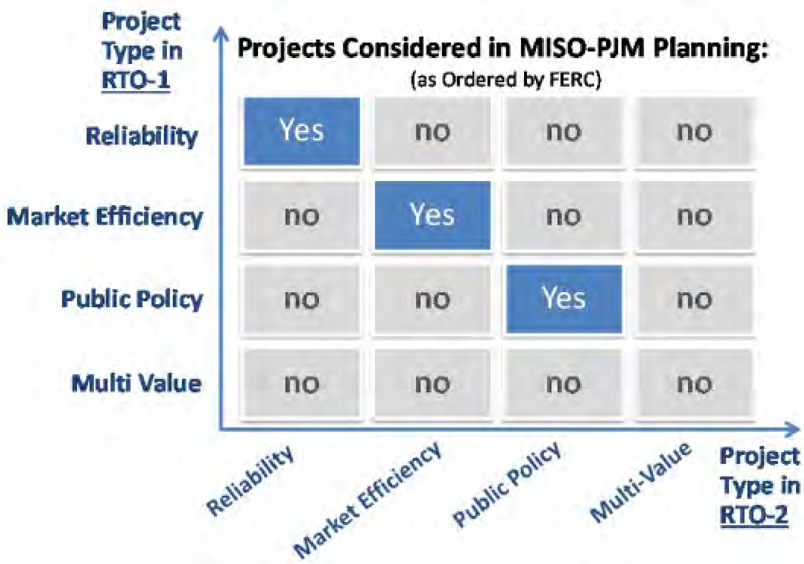
Most of the existing joint interregional planning processes (such as the PJM-MISO interregional planning process) allow only for the evaluation of transmission needs that are of the same type (*i.e.*, reliability, market efficiency, or public policy) in both regions. As illustrated in Figure 13,[143] these types of interregional planning processes may not allow for the evaluation of needs that differ across the regions, which can disqualify from consideration many valuable interregional projects.

[141] This approach is widely used for infrastructure costs, such as roads or distribution systems. The portfolio-based approach has also been applied, for example, by SPP for the highway-byway cost allocation of projects approved through its Integrated Transmission Planning (ITP) process and MISO for the postage-stamp-based cost allocation of its portfolio of Multi-Value Projects (MVP). While SPP and MISO have demonstrated that the benefits of portfolio of projects are roughly commensurate with allocated costs, the cost allocation approach would not meet that standard for individual ITP and MVP projects. Note, however, that the approval of individual projects (or synergistic groups of projects) still needs to be based on the need for and total benefits of the individual projects.

[142] Southwest Power Pool, *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012; Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, prepared for WIRES Group, April 2015.

[143] For a summary of the PJM-MISO interregional planning process, see Appendix C of Pfeifenberger, Chang, Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, Prepared for WIRES Group, April 2015.

FIGURE 13. SOME INTERREGIONAL PLANNING PROCESSES DO NOT ALLOW FOR THE EVALUATION OF PROJECTS THAT ADDRESS DIFFERENT NEEDS IN EACH RTO

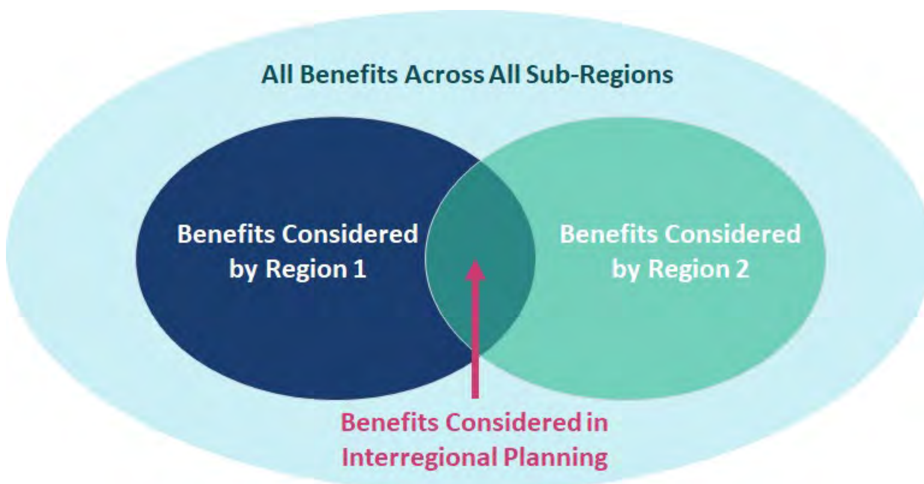


By focusing only on projects that address reliability, market efficiency, or public policy needs in both regions, the planning process inadvertently excludes any interregional projects that, for example, would address reliability needs in one region but address market efficiency or public policy needs in the neighboring region. Unless the two adjacent regions categorize the interregional project in exactly the same way, the regions' interregional planning rules do not exist or may outright reject evaluating the project. More often than not, however, a transmission project will provide multiple types of benefits and these benefits may differ across regions. Finding and approving transmission solutions solely based on reliability needs can, thus, lead to missed opportunities to build lower-cost or higher-value transmission projects that could provide benefits beyond meeting reliability needs to reduce the overall costs and risks to customers in both regions.

The geographic scope of regional and interregional RTO planning processes tends to be narrowly focused in its consideration of the transmission-related benefits geographic scope, typically quantifying only a subset of transmission-related economic and public policy benefits and considering only benefits that accrue to their own region without considering the broader set of interregional benefits. Projects near the regional boundaries, such as an upgrade to a shared flowgate, can address the needs of neighboring regions and need to be considered if the goal is to determine the infrastructure that most lowers cost. Without considering this, quantified benefits will be understated and even "regional" projects near RTO seams could fail to meet applicable benefit-cost thresholds for regional market-efficiency and public policy needs simply because the planning process ignores the benefits that accrue on the other side of the seam. This limitation has been addressed in some interregional planning processes (*e.g.*, PJM-MISO and MISO-SPP joint interregional planning[144]), but is often not considered in regional planning for projects located entirely within one of the RTOs.

This approach tends to disadvantage interregional projects because the jointly agreed-upon criteria and metrics generally will tend to represent the "*least common denominator*" subset of the criteria and metrics used in the adjoining regions. Worse, as show, the range of benefits considered for interregional projects tends be more limited than the narrow scope of benefits considered in intra-regional planning processes, reducing the set of benefits to the least-common denominator of benefits considered in planning within each of the two regions. Similarly, interregional planning processes do not recognize the unique benefits often offered by an expanded interregional transmission system, which include increased load and resource diversity.[145]

FIGURE 14. THE "LEAST COMMON DENOMINATOR" CHALLENGE OF BENEFIT-COST ANALYSIS FOR INTERREGIONAL PROJECTS



In addition, barriers can be created due to the disjointed nature of the existing interregional and regional planning processes. For example, interregional transmission projects may be subjected to three separate benefit-cost thresholds: a joint interregional benefit-cost threshold as well as each of the two neighboring region's individual internal planning criteria. This means, for example, that projects that pass each RTO's individual benefit-cost thresholds may fail the threshold imposed through the least-common denominator approach to interregional planning;

[144] SPP-MISO and MISO-PJM Joint Operating Agreements available at MISO, *Interregional Coordination*.

[145] Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, BU-ISE, October 14, 2020.

or projects that pass the benefit-cost threshold of the interregional planning process may be rejected because they may fail one of the individual RTOs' planning criteria. In combination with evaluating only a subset of benefits of a few scenarios of future market conditions, this adds to the challenge of approving even very valuable projects.

Interregional planning also lacks proactive scenario-based analyses. This is partly caused by the lack of inputs from states on how they plan on achieving clean energy goals. States generally have specific goals for local renewable energy resource development that are not well articulated or challenging to incorporate into regional and interregional planning processes. One of the key drivers of the MISO MVP process was that state representatives were requesting that MISO evaluate transmission solutions that could cost-effectively meet the region's combined state-level renewable portfolio standards by integrating a combination of local and regional renewable resources. A high-level outlook of how states wish to pursue meeting their goals, or a more detailed set of scenarios, would greatly improve the ability of RTOs to plan their future system without having to develop a specific portfolio of resources to do so.

6. Summary of Examples of Proven Efficient Planning Studies and Methods

As described above, there are many examples where efficient transmission planning methods have been performed. The following table lists transmission studies and analyses and shows what type of planning method was performed (Table 7). Table 7 classifies proactive as considering beyond status-quo scenarios, multi-benefit as considering a comprehensive set of benefits (*i.e.*, not just a couple), and scenario-based planning to reflect a broad set of divergent futures.

TABLE 7. EXAMPLES USING PROVEN EFFICIENT PLANNING METHODS

	Proactive Planning	Multi-Benefit	Scenario-Based	Portfolio-Based	Interregional Transmission
CAISO TEAM (2004)[146]	✓	✓	✓		
ATC Paddock-Rockdale (2007)[147]	✓	✓	✓		
ERCOT CREZ (2008)[148]	✓			✓	
MISO RGOS (2010)[149]	✓	✓		✓	
EIPC (2010-2013)[150]	✓		✓	✓	✓
PJM renewable integration study (2014)[151]	✓		✓	✓	
NYISO PPTPP (2019)[152]	✓	✓	✓	✓	
ERCOT LTSA (2020)[153]	✓		✓		
SPP ITP Process (2020)[154]		✓		✓	
PJM Offshore Tx Study (2021)[155]	✓		✓	✓	
MISO RIIA (2021)[156]	✓	✓	✓	✓	
Australian Examples:					
- AEMO ISP (2020)[157]	✓	✓	✓	✓	✓
- Transgrid Energy Vision (2021)[158]	✓	✓	✓	✓	✓

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146 CAISO, Transmission Economic Assessment Methodology (TEAM), June 2004.

147 American Transmission Company, Planning Analysis of the Paddock-Rockdale Project, April 2007.

148 D. Woodfin (ERCOT), *CREZ Transmission Optimization Study Summary*, presented to the ERCOT Board of Directors, April 15, 2008.

149 Midwest ISO, *RGOS: Regional Generation Outlet Study*, November 19, 2010.

150 See *Eastern Interconnection Planning Collaborative*, including Phase I and Phase II planning reports

151 GE Energy Consulting, *PJM Renewable Integration Study, Task 3A Part C: Transmission Analysis*, March 31, 2014.

152 NYISO, AC Transmission Public Policy Transmission Plan, April 8, 2019.

153 ERCOT, *2020 LTSA Review*, December 15, 2020 and *2020 Long-Term System Assessment for the ERCOT Region*, December 20202, as posted at: Planning (ercot.com).

154 SPP, *2020 Integrated Transmission Planning Report*, October 27, 2020. As noted in the report (at p 8), the (multi-value) objectives of the SPP ITP process are to: resolve reliability criteria violations; Improve access to markets; Improve interconnections with SPP neighbors; meet expected load-growth demands; facilitate or respond to expected facility retirements; synergize with the Generator Interconnection (GI), Aggregate Transmission Service Studies (ATSS), and Attachment AQ processes; address persistent operational issues as defined in the scope; Facilitate continuity in the overall transmission expansion plan; and facilitate a cost-effective, responsive, and flexible transmission network.

155 PJM, *Offshore Transmission Study Group Phase 1 Results,* presented to Independent State Agencies Committee (ISAC), July 29, 2021.

156 Midwest ISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, February 2021.

157 AEMO, *2020 Integrated System Plan*, July 30, 2020.

158 Transgrid, *Energy Vision: A Clean Energy Future for Australia*, October 2021.

V. Summary and Conclusions

The currently predominant use of reactive, single-driver approaches to transmission planning is systematically failing to identify and implement transmission options that offer the lowest system-wide costs and highest benefits for customers. A set of market and regulatory failures create perverse incentives that lead to under-investment in the type of regional and interregional transmission that would increase reliability and system-wide efficiency.

This failure is widespread across the country, and present to a greater or lesser extent in all 11 Planning Authority regions. These transmission planning processes are not leading to a cost-effective transmission infrastructure. Fortunately, some proven examples of more effective transmission planning, using existing and readily available tools, exist. Continuing current practices without reforms will mean higher-than-necessary electricity costs. Existing experience with effective planning and cost-allocation processes shows that transmission planners have the tools needed to significantly reduce system-wide electricity costs. To do so, effective planning process need to:

1. **Proactively plan for future generation and load** by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.
2. **Account for the full range of transmission projects' benefits** and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.
3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.
4. **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.
5. **Jointly plan across neighboring interregional systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

Policymakers and planners need to reform transmission planning requirements to avoid the unreasonably high system-wide costs that result from the current planning approaches and enable customers to pay just and reasonable rates by implementing these principles.

Appendix A – Evidence of the Need for Regional and Interregional Transmission Infrastructure to Lower Costs

Numerous studies of the future resource mix find that large amounts of power must be able to move back and forth across regions, and large regional and interregional transmission expansion is needed for this to happen. This evidence includes:

- A study by leading grid experts at the National Oceanic and Atmospheric Administration (NOAA) found that moving away from a regionally divided network to a national network of HVDC transmission can save consumers up to $47 billion annually while integrating 523 GWs of wind and 371 GWs of solar onto the grid.[159]
- The NREL Interconnections Seam Study shows that significant transmission expansion and the creation of a national network will be essential in incorporating high levels of renewable resources, all the while returning more than $2.50 for every dollar invested.[160] The study found a need for 40–60 million MW-miles of alternating current (AC) and up to 63 million MW-miles of direct current (DC) transmission for one scenario. The U.S. has approximately 150 million MW-miles in operation today.
- A study by ScottMadden Management Consultants on behalf of WIRES, concluded that as more states, utilities, and other companies are mandating or committing to clean energy targets and agendas, it will not be possible to meet those goals without additional transmission to connect desired resources to load. Similarly, the current transmission system will need further expansion and hardening beyond the traditional focus on meeting reliability needs if the system is to be adequately designed and constructed to withstand and timely recover from disruptive or low probability, high-impact events affecting the resilience of the bulk power system."[161]

[159] Alexander E. MacDonald et al., *Future Cost-Competitive Electricity Systems and Their Impact on U.S. CO2 Emissions*, Nature Climate Change 6, at 526-531, January 25, 2016.

[160] Aaron Bloom, *Interconnections Seam Study*, August 2018.

[161] Scott Madden, *Informing the Transmission Discussion: A Look at Renewables Integration and Resilience Issues for Power Transmission in Selected Regions of the United States*, January 2020.

- Dr. Paul Joskow of MIT has reviewed transmission planning needs and concluded that "[s]ubstantial investment in new transmission capacity will be needed to allow wind and solar generators to develop projects where the most attractive natural wind and solar resources are located. Barriers to expanding the needed inter-regional and internetwork transmission capacity are being addressed either too slowly or not at all."[162]
- The Commission itself recently reviewed transmission needs and barriers and "found that high voltage transmission, as individual lines or as an overlay, can improve reliability by allowing utilities to share generating resources, enhance the stability of the existing transmission system, aid with restoration and recovery after an event, and improve frequency response and ancillary services throughout the existing system."[163]
- A study of the Eastern Interconnection for the state of Minnesota found that scenarios with interstate transmission expansion can introduce annual savings to Minnesota consumers of up to $2.8 billion, with an annual savings for Minnesotan households of up to $1,165 per year.[164]
- Analysts at The Brattle Group estimate that providing access to areas with lower cost generation to meet Renewable Portfolio Standards (RPS) and clean energy needs through 2030 could create $30–70 billion in benefits for customers, and multiple studies have identified potential benefits of over $100 billion.[165]
- The Princeton University Net Zero America study of a low carbon economy found "[h]igh voltage transmission capacity expands ~60% by 2030 and triples through 2050 to connect wind and solar facilities to demand; total capital invested in transmission is $360 billion through 2030 and $2.4 trillion by 2050."[166]
- A study by MIT scientists found that inter-state coordination and transmission expansion reduces the cost of zero-carbon electricity by up to 46% compared to a state-by-state

[162] Paul Joskow, *Transmission Capacity Expansion is Needed to Decarbonize the Electricity Sector Efficiently*, Joule 4, at 1-3, January 15, 2020. See also Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector*, Economics of Energy & Environmental Policy, Vol. 10, No. 2 (2021).

[163] FERC, *Report on Barriers and Opportunities for High Voltage Transmission*, at 39, June 2020.

[164] Vibrant Clean Energy, *Minnesota's Smarter Grid*, July 31, 2018.

[165] J. Michael Hagerty, Johannes Pfeifenberger, and Judy Chang, *Transmission Planning Strategies to Accommodate Renewables*, at 17, September 11, 2017.

[166] Eric Larson, *et al.*, *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, at 77, December 15, 2020.

approach.[167] To achieve these cost reductions the study found a need for approximately doubling transmission capacity, and "[e]ven in the ''5× transmission cost'' case there are substantial transmission additions."[168]

- A recent study to compare the "flexibility cost-benefits of geographic aggregation, renewable overgeneration, storage, and flexible electric vehicle charging," as "pathways to a fully renewable electricity system" found that "[g]eographic aggregation provides the largest flexibility benefit with ~5–50% cost savings.[169] The study found that "With a major expansion of long-distance transmission interconnection to smooth renewable energy variation across the continent, curtailment falls to negligible levels at a 60% renewable penetration, from 5% in the case without transmission. In the 80% renewable case, transmission reduced curtailment from 12% to 5%.[170]
- The Brattle Group analysts find that "$30–90 billion dollars of incremental transmission investments will be necessary in the U.S. by 2030 to meet the changing needs of the system due to electrification, with an additional $200–600 billion needed from 2030 to 2050."[171]
- Analysis conducted for MISO found that significant transmission expansion was economical under all future scenarios, with the largest transmission expansion needed in Minnesota, the Dakotas, and Iowa. In the carbon reduction case, transmission provided $3.8 billion in annual savings, reducing total power system costs by 5.3%.[172]
- MISO's Renewable Integration Impact Assessment conducted a diverse set of power system studies examining up to 50% Variable Energy Resources (VER) (570GW VER) in the eastern interconnection. Within the MISO footprint, this included the following transmission expansion: 590 circuit-miles of 345kV and below, 820 circuit-miles of 500kV, 2040 circuit-miles of 765kV, and 640 circuit-miles of HVDC.[173]

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[167] P. R. Brown and A. Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, Joule, December 11, 2020.

[168] *Id.*, at 12.

[169] B. A. Frew, *et al.*, *Flexibility Mechanisms and Pathways to a Highly Renewable U.S. Electricity Future*, Energy, Volume 101, at 65-78, April 15, 2016.

[170] *Ibid*.

[171] Dr. J. Weiss, J. M. Hagerty, and M. Castañer, *The Coming Electrification of the North American Economy*, at ii, March 2019.

[172] Vibrant Clean Energy, *MISO High Penetration Renewable Energy Study for 2050*, at 23-24, January 2016

[173] Wind Solar Alliance, *Renewable Integration Impact Assessment Finding Integration Inflection Points of Increasing Renewable Energy*, January 21, 2020.

- The Brattle Group analysts, on behalf of WIRES, demonstrate that transmission expansion creates trading opportunities across existing regional and interregional constraints. The report finds, using existing wholesale power price differences between SPP and the Northwestern U.S., that "adding 1,000 MW of transmission capability would create approximately $3 billion in economic benefits on a present value basis."[174]
- In its HVDC Network Concept study, MISO estimates that expanding east-to-west and north-to-south transmission interties can generate investment cost savings of approximately $38 billion through load diversity benefits that would reduce nation-wide generation capacity needs by 36,000 MW.[175]
- A study prepared for the Eastern Interconnection States Planning Council, National Association of Regulatory Utility Commissioners, and the Department of Energy estimates that $50–110 billion of interregional transmission will be needed over the next 20 years to cost-effectively support new generation investment. A co-optimized, anticipatory transmission planning process is estimated to reduce total generation costs by $150 billion, compared to a traditional transmission planning approach, and would generate approximately $90 billion in overall system-wide savings.[176]
- SPP found that a portfolio of transmission projects constructed in the region between 2012 and 2014 at a cost of $3.4 billion is estimated to generate upwards of $12 billion in net benefits over the next 40 years. The net present value is expected to total over $16.6 billion over the 40-year period, resulting in a benefit-to-cost ratio of 3.5.[177]
- MISO estimates that its 17 Multi-Value Projects (MVPs), approved in 2011, will generate between $7.3 to $39 billion in net benefits over the next 20 to 40 years, which will result in a total cost-benefit ratio of between 1.8 to 3.1. Typical residential households could realize an estimated $4.23 to $5.13 in monthly benefits over the 40-year period.[178]
- A study conducted by the Eastern Interconnection Planning Collaborative on the need for interregional transmission projects to meet national environmental goals found that an efficient interregional transmission planning approach to meet a 25% nation-wide RPS

[174] Pfeifenberger and Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon Constrained Future*, at 16, June 2016.

[175] MISO, *HVDC Network Concept*, at 3, January 7, 2014.

[176] A. Liu, *et al.*, *Co-optimization of Transmission and Other Supply Resources*, September 2013.

[177] SPP, *The Value of Transmission*, at 5, January 26, 2016.

[178] MISO, *MTEP19*, 2019.

standard would reduce generation costs by $163–$197 billion compared to traditional planning approaches.[179]

- Phase 2 of the study found that the transmission investment necessary to support the generation and the environmental compliance scenarios associated with these savings ranges from $67 to $98 billion.[180] These results indicate that the combination of interregional environmental policy compliance and interregional transmission may offer net savings of up to $100 billion.
- A study comparing proactive planning to reactive planning found significant benefits to proactive planning because it is able to co-optimize generation and transmission. "Transmission planning has traditionally followed a "generation first" or "reactive" logic, in which network reinforcements are planned to accommodate assumed generation build-outs. The emergence of renewables has revealed deficiencies in this approach, in that it ignores the interdependence of transmission and generation investments. For instance, grid investments can provide access to higher quality renewables and thus affect plant siting. Disregarding this complementarity increases costs. In theory, this can be corrected by "proactive" transmission planning, which anticipates how generation investment responds by co-optimizing transmission and generation investments. We evaluate the potential usefulness of co-optimization by applying a mixed-integer linear programming formulation to a 24-bus stakeholder-developed representation of the U.S. Eastern Interconnection. We estimate cost savings from co-optimization compared to both reactive planning and an approach that iterates between generation and transmission investment optimization. These savings turn out to be comparable in magnitude to the amount of incremental transmission investment."[181]

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[179] Eastern Interconnection Planning Collaborative, *Phase 1 Report: Formation of Stakeholder Process, Regional Plan Integration and Macroeconomic Analysis*, December 2011.

[180] Eastern Interconnection Planning Collaborative, *Phase 2 Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios and Gas-Electric System Interface Study*, June 2, 2015.

[181] E. Spyrou, J. L. Ho, B. F. Hobbs, R. M. Johnson, and J. D. McCalley, *What Are the Benefits of Co-Optimizing Transmission and Generation Investment? Eastern Interconnection Case Study*. IEEE Transactions on Power Systems 32 (6): 4265–77, January 27, 2017.

Appendix B – Quantifying the Additional Production Cost Savings of Transmission Investments

As noted in the main report, RTOs and transmission planners are increasingly recognizing that traditional production cost simulations and the traditional "adjusted production cost" metrics are quite limited in their ability to estimate the full congestion relief and production cost benefits. Below we describe the quantification of additional production-cost-related savings (*i.e.*, beyond the production cost savings traditionally quantified) that need to be considered when evaluating the full range of transmission benefits.

TABLE 8. ADDITOINAL PRODUCTION COST SAVING CATEGORIES

i. Impact of generation outages and A/S unit designations
ii. Reduced transmission energy losses
iii. Reduced congestion due to transmission outages
iv. Reduced production cost during extreme events and system contingencies
v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
vii. Reduced cost of cycling power plants
viii. Reduced amounts and costs of operating reserves and other ancillary services
ix. Mitigation of reliability-must-run (RMR) conditions
x. More realistic "Day 1" market representation

B.1 Estimating Changes in Transmission Losses

In some cases, transmission additions or upgrades can reduce the energy losses incurred in the transmittal of power from generation sources to loads. However, due to significant increases in simulation run-times, a constant loss factor is typically provided as an input assumption into the production cost simulations. This approach ignores that the transmission investment may reduce the total quantity of energy that needs to be generated, thereby understating the production cost savings of transmission upgrades.

To properly account for changes in energy losses resulting from transmission additions will require either: (1) simulating changes in transmission losses; (2) running power flow models to estimate changes in transmission losses for the system peak and a selection of other hours; or (3) utilizing marginal loss charges (from production cost simulations with constant loss approximation) to estimate how the cost of transmission losses will likely change as a result of the transmission investment.[182] Through any of these approaches, the additional changes in production costs associated with changes in energy losses (if any) can be estimated.

In some cases, the economic benefits associated with reduced transmission losses can be surprisingly large, especially during system peak-load conditions. For instance, the energy cost savings of reduced energy losses associated with a 345 kV transmission project in Wisconsin were sufficient to offset roughly 30% of the project's investment costs.[183] Similarly, in the case of a proposed 765 kV transmission project, the present value of reduced system-wide losses was estimated to be equal to roughly half of the project's cost.[184] For transmission projects that specifically use advanced technologies that reduce energy losses, these benefits are particularly important to capture. For example, a recent analysis of a proposed 765 kV project using "low-loss transmission" technology showed that this would provide an additional $11 to 29 million in annual savings compared to the older technology.[185]

B.2 Estimating the Additional Benefits Associated with Transmission Outages

Production cost simulations typically consider planned generation outages and, in most cases, a random distribution of unplanned generation outages. In contrast, they do not generally reflect *transmission* outages, planned or unplanned. Both generation and transmission outages can have significant impacts on transmission congestion and production costs. By assuming that transmission facilities are available 100% of the time, the analyses tend to under-estimate the value of transmission upgrades and additions because outages, when they occur, typically

[182] For a discussion of estimating loss-related production cost savings from the marginal loss results of production cost simulations see Pfeifenberger, Direct Testimony on behalf of American Transmission Company, before the Public Service Commission of Wisconsin, Docket 137-CE-149, January 17, 2008.

[183] American Transmission Company LLC (ATC), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598), pp 4 (project cost) and 63 (losses benefit).

[184] Pioneer Transmission, LLC, Letter from David B. Raskin and Steven J. Ross (Steptoe & Johnson) to Hon. Kimberly D. Bose (FERC) Re: Formula Rate and Incentive Rate Filing, Pioneer Transmission LLC, Docket No. ER09-75-000, no attachments, January, 26, 2009, at p 7. These benefits include not only the energy value (*i.e.*, production cost savings) but also the capacity value of reduced losses during system peak.

[185] Pfeifenberger and S. A. Newell, Direct Testimony, FERC Docket No. ER11-4069-000 (RITELine), filed July 18, 2011.

cause transmission constraints to bind more frequently and increase transmission congestion and the associated production costs significantly.[186]

Transmission outages account for a significant and increasing portion of real-world congestion. For example, when the PJM FTR Task Force reported a $260 million FTR congestion revenue inadequacy (or approximately 18% of total PJM congestion revenues during the 2010–11 operating year), approximately 70% of this revenue inadequacy was due to major construction-related transmission outages (16%), maintenance outages (44%), and unforeseen transmission de-ratings or forced outages (9%). In fact, the frequency of PJM transmission facility rating reductions due to transmission outages has increased from approximately 500 per year in 2007 to over 2,000 in 2012.[187] Similarly, while the exact amount attributable to transmission outages is not specified, the Midwest ISO's independent market monitor noted that congestion costs in the day-ahead and real-time markets in 2010 rose 54 percent to nearly $500 million due to higher loads and transmission outages.[188] MISO also recently addressed the challenge of FTR revenue inadequacy by using a representation of the transmission system in its simultaneous FTR feasibility modeling that incorporates planned outages and a derate of flowgate capacity to account for unmodelled events such as unplanned transmission outages and loop flows.[189] As aging transmission facilities need to be rebuilt, the magnitude and impact of transmission outages will only increase.

A 2005 study of PJM assessed the impact of transmission outages. That analysis showed that without transmission outages, total PJM congestion charges would have been 20% lower; the value of FTRs from the AEP Generation Hub to the PJM Eastern Hub would have been 37% lower; the value of FTRs into Atlantic Electric, for example, would have been more than 50% lower; and that simulations without outages generally understated prices in eastern PJM and

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[186] For an additional discussion of simulating the transmission outage mitigation value of transmission investments, see Southwest Power Pool (SPP), *SPP Priority Projects Phase II Report, Rev. 1*, April 27, 2010, Section 4.3.

Also note that, while not related to production costs, the transmission outages can also result in reduced system flexibility that can delay certain maintenance activities (because maintenance activities could require further line outages), which in turn can reduce network reliability.

[187] PJM Interconnection (PJM), *FTR Revenue Stakeholder Report*, April 30, 2012, p 32.

[188] D. Patton, "*2010 State of the Market Report: Midwest ISO*," presented by Midwest ISO Independent Market Monitor, Potomac Economics, May 2011. (Patton, 2011) Posted at https://www.potomaceconomics.com/wp-content/uploads/2017/02/2010-State-of-the-Market-Presentation.pdf, 2011.

[189] See Section 7.1 (Simultaneous Feasibility Test) of the MISO Business Practices Manual 4. Posted at: https://cdn.misoenergy.org//BPM%20004%20-%20FTR%20and%20ARR49548.zip.

west-east price differentials.[190] These examples show that real-world congestion costs are higher than congestion costs in a world without transmission outages. This means that the typical production cost simulations, which do not consider transmission outages, tend to understate the extent of congestion on the system and, as a result, the congestion-relief benefit provided by transmission upgrades.

Production cost simulations can be augmented to reflect reasonable levels of outages, either by building a data set of a normalized outage schedule (not including extreme events) that can be introduced into simulations or by reducing the limits that will induce system constraints more frequently. For the RITELine transmission project, specific production cost benefits were analyzed for the planned outages of four existing high-voltage lines. It was found that a one-week (non-simultaneous) outage for each of the four existing lines increased the production cost benefits of the RITELine project by more than $10 million a year, with PJM's Load locational pricing payments decreasing by more than $40 million a year. Because there are several hundred high-voltage transmission elements in the region of the proposed RITELine, the actual transmission-outage-related savings can be expected to be significantly larger than the simulated savings for the four lines examined in that analysis.[191]

At the time of writing this report, our ongoing work for SPP indicates that applying the most important transmission outages from the last year to forward-looking simulations of transmission investments increases the estimates of adjusted production cost savings by approximately 10% to 15% even under normalized system (*e.g.*, peak load) conditions. Higher additional transmission–outage-related savings are expected in portions of the grid that already have very limited operating flexibility and during challenging (*i.e.*, not normalized) system conditions.

The fact that transmission outages increase congestion and associated production costs is also documented for non-RTO regions. For example, Entergy's Transmission Service Monitor (TSM) found that transmission constraints existed during 80% of all hours, leading to 331 curtailments of transmission services, at least some of which was the result of the more than 2,000 transmission outages that affected available transmission capability during a three month period.[192] The TSM report also showed that, for the five most constrained flowgates on the

[190] Pfeifenberger and S. Newell, "*Modeling Power Markets: Uses and Abuses of Locational Market Simulation Models*," Energy (Brattle Group Newsletter) No. 1, 2006.

[191] Pfeifenberger and S. A. Newell, Direct Testimony, FERC Docket No. ER11-4069-000 (RITELine), filed July 18, 2011.

[192] Potomac Economics, Quarterly Transmission Service Monitoring Report on Entergy Services, Inc.¸ December 2012 through March 2013, April 30, 2013.

Entergy system, the available flowgate capacity during real-time operations generally fluctuated by several hundred MW over time. This means that the actual available transmission capacity is less on average than the limits used in the market simulation models, which assume a constant transmission capability equal to the flowgate limits used for planning purposes. This indicates that the traditional simulations tend to understate transmission congestion by not reflecting the lower transmission limits in real-time. The TSM report also stated that the identified transmission constraints resulted in the refusal of transmission service requests for approximately 1.2 million MWh during the same three month period.

These examples show that real-world congestion costs are higher than the congestion costs simulated through traditional production cost modeling that assumes a world without transmission outages. These values associated with new transmission's ability to mitigate the cost of transmission outages will be particularly relevant in areas of the grid with constrained import capability and limited system flexibility.

B.3 Estimating the Benefits of Mitigating the Impacts of Extreme Events and System Contingencies

Transmission upgrades can provide insurance against extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages. Even if a range of typical generation and transmission outage scenarios are simulated during analyses of proposed projects, production cost simulations will not capture the impacts of extreme events; nor will they capture how proposed transmission investments can mitigate the potentially high costs resulting from these events. Although extreme events occur very infrequently, when they do they can significantly reduce the reliability of the system, induce load shed events, and impose high emergency power costs. Production cost savings from having a more robust transmission system under these circumstances include the reduction of high-cost generation and emergency procurements necessary to support the system. Additional economic value (discussed further below) includes the value of avoided load shed events.

The insurance value of additional transmission in reducing the impact of extreme events can be significant, despite the relatively low likelihood of occurrence. While the value of increased system flexibility during extreme contingencies is difficult to estimate, system operators intrinsically know that increased system flexibility provides significant value. One approach to estimate these additional values is to use extreme historical market conditions and calculate the probability-weighted production cost benefits through simulations of the selected extreme events. For example, a production cost simulation analysis of the insurance benefits for the

Paddock-Rockdale 345 kV transmission project in Wisconsin found that the project's probability-weighted savings from reducing the production and power purchase costs during a number of simulated extreme events (such as multiple transmission or nuclear plant outages similar to actual events that occurred in prior years) added as much as $28 million to the production cost savings, offsetting 20% of total project costs.[193]

For the PVD2 project, several contingency events were modeled to determine the value of the line during these high-impact, low-probability events. The events included the loss of major transmission lines and the loss of the San Onofre nuclear plant. The analysis found significant benefits, including a 61% increase in energy benefits, to CAISO ratepayers in the case of the San Onofre outage.[194] This simulated high-impact, low-probability event turned out to be quite real, as the San Onofre nuclear plant has been out of service since early 2012 and will now be closed permanently.[195]

Further, the analysis of high-impact, low-probability events documented that—while the estimated societal benefit (including competitive benefit) of the PVD2 line was only $77 million for 2013—there was a 10% probability that the annual benefit would exceed $190 million under various combinations of higher-than-normal load, higher-than-base-case gas prices, lower-than-normal hydro generation, and the benefits of increased competition. There was also a 4.8% probability that the annual benefit ranged between $360 and $517 million.[196]

In a recent example, one such study found that the development of an additional 1,000 MW of transmission capacity into Texas during would have fully paid for itself over the course of four days during winter storm Uri.[197] The same study found that an additional 1,000 MW of transmission capacity into MISO from the East would have saved $100 million during that short period of time.

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[193] American Transmission Company LLC (ATC), *Planning Analysis of the Paddock-Rockdale Project*, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598, p 4 (project cost) and 50-53 (insurance benefit).

[194] California Public Utilities Commission (CPUC), Decision 07-01-040: *Opinion Granting a Certificate of Public Convenience and Necessity*, in the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project, Application 05-04-015 (filed April 11, 2005), January 25, 2007, pp 37–41.

[195] M. L. Wald, "Nuclear Power Plant in Limbo Decides to Close, *The New York Times*, June 7, 2013.

[196] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005, p 24.

[197] M. Goggin (Grid Strategies, LLC), *Transmission Makes the Power System Resilient to Extreme Weather*, Prepared for ACORE, with Support from the Macro Grid Initiative, July 2020.

B.4 Estimating the Benefits of Mitigating Weather and Load Uncertainty

Production cost simulations are typically performed for all hours of the year, though the load profiles used typically reflect only normalized monthly and peak load conditions. Such methodology does not fully consider the regional and sub-regional load variances that will occur due to changing weather patterns and ignores the potential benefit of transmission expansions when the system experiences higher-than-normal load conditions or significant shifts in regional weather patterns that change the relative power consumption levels across multiple regions or sub-regions. For example, a heat wave in the southern portion of a region, combined with relatively cool summer weather in the north, could create much greater power flows from the north to the south than what is experienced under the simulated normalized load conditions. Such greater power flows would create more transmission congestion and greater production costs. In these situations, transmission upgrades would be more valuable if they increased the transfer capability from the cooler to hotter regions.[198]

SPP's Metrics Task Force recently suggested that SPP's production simulations should be developed and tested for load profiles that represent 90/10 and 10/90 peak load conditions—rather than just for base case simulations (reflecting 50/50 peak load conditions)—as well as scenarios reflecting north-south differences in weather patterns.[199] Such simulations may help analyze the potential incremental value of transmission projects during different load conditions. While it is difficult to estimate how often such conditions might occur in the future, they do occur, and ignoring them disregards the additional value that transmission projects provide under these circumstances. For example, simulations performed by ERCOT for normal loads, higher-than-normal loads, and lower-than-normal loads in its evaluation of a Houston Import Project showed a $45.3 million annual consumer benefit for the base case simulation (normal load) compared to a $57.8 million probability-weighted average of benefits for all three simulated load conditions.[200]

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[198] Because the incremental system costs associated with higher-than-normal loads tend to exceed the decremental system costs of lower-than-normal loads, the probability-weighted average production costs across the full spectrum of load conditions tend to be above the production costs for normalized conditions.

[199] Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012, Section 9.6.

[200] Energy Reliability Council of Texas (ERCOT), *Economic Planning Criteria: Question 1: 1/7/2011 Joint CMWG/PLWG Meeting*, March 4, 2011, p10. The $57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant's estimated probabilities for the same scenarios.

Mitigating the variability and uncertainty of renewable generation by diversifying it over geographic areas that exceed in size the scale of typical weather system has also been shown to provide substantial economic benefits, but requires the explicit simulation of both renewable generation variability and the day-ahead and intra-day uncertainty associated with intra-hour real-time generation as discussed in more detail in the subsection below.[201]

B.5 Estimating the Impacts of Imperfect Foresight of Real-Time System Conditions

Another simplification inherent in traditional production cost simulations is the deterministic nature of the models that assumes perfect foresight of all real-time system conditions. Assuming that system operators know exactly how real-time conditions will materialize when system operators must commit generation units in the day-ahead market means that the impact of many real-world uncertainties are not captured in the simulations. Changes in the forecasted load conditions, intermittent resource generation, or plant outages can significantly change the transmission congestion and production costs that are incurred due to these uncertainties.

Uncertainties associated with load, generation, and outages can impose additional costs during unexpected real-time conditions, including over-generation conditions that impose additional congestion costs. For example, comparing the number of negatively priced hours in the real-time versus the day-ahead markets in the ComEd load zone of PJM provides an example of how dramatically load and intermittent resource conditions can change.[202] From 2008 to 2010, there were 763 negatively priced hours in the real-time market, but only 99 negatively priced hours in the day-ahead market. The increase in negative prices in the real-time, relative to the day-ahead, market is due to the combined effects of lower-than-anticipated loads with the significantly higher-than-predicted output of intermittent wind resources. While this example illustrates the impact of uncertainties within the day-ahead time frame, traditional production cost simulations do not consider these uncertainties and their impacts.

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[201] Pfeifenberger, Ruiz, and Van Horn, *The Value of Diversifying Uncertain Renewable Generation Through the Transmission System*, BU-ISE Working Paper, September 2020.

[202] Pfeifenberger and Newell, Direct Testimony, FERC Docket No. ER11-4069-000 (RITELine), filed July 18, 2011.

In a recent study, analysts at The Brattle Group and researchers at Boston University estimated the value of diversifying uncertain renewable generation through the transmission system.[203] The analysis indicates that the benefits of transmission expansion between areas with diverse renewable generation resources are greater than typically estimated, with significant reductions in system-wide costs and renewable generation curtailments in both hourly day-ahead and intra-hour power market operations. For renewable generation levels from 10% to 60% of annual energy consumption, interconnecting two power market sub-regions with different wind regimes through transmission investments can reduce annual production costs by between 2% and 23% and annual renewable curtailments by 45% to 90%. When real-time uncertainties of renewable generation and loads relative to their day-ahead forecasts are taken into consideration, the benefit of geographic diversification through the transmission grid are 2 to 20 times higher than benefits typically quantified based only on "perfect forecasts."

Thus, to estimate the additional benefits that transmission upgrades can provide with the uncertainties associated with actual real-time system conditions, traditional production cost simulations need to be supplemented. For example, existing tools can be modified so that they simulate one set of load and generation conditions anticipated during the time that the system operators must commit the resources, and another set of load and generation conditions during real-time. The potential benefits of transmission investments also extend to uncertainties that need to be addressed through intra-hour system operations, including the reduced quantities and prices for ancillary services (such as regulation and spinning reserves) needed to balance the system as discussed further below.[204] These benefits will generally be more significant if transmission investments allow for increased diversification of uncertainties across the region, or if the investments increase transmission capabilities between renewables-

[203] Pfeifenberger, *Ruiz, Van Horn.*, The Value of Diversifying Uncertain Renewable Generation through the Transmission System: Cost Savings Associated with Interconnecting Systems with High Renewables Generation: Cost Savings Associated with Interconnecting Systems with High Renewables Penetration, presented for Boston University Institute for Sustainable Energy Webinar Series, October 14, 2020.

[204] For example, a recent study for the National Renewable Energy Laboratory (NREL) concluded that, with 20% to 30% wind energy penetration levels for the Eastern Interconnection and assuming substantial transmission expansions and balancing-area consolidation, total system operational costs caused by wind variability and uncertainty range from $5.77 to $8.00 per MWh of wind energy injected. The day-ahead wind forecast error contributes between $2.26/MWh and $2.84/MWh, while within-day variability accounts for $2.93/MWh to $5.74/MWh of wind energy injected. ($/MWh in US$2024). EnerNex Corporation, prepared for National Renewable Energy Laboratory (NREL), NREL/SR-5500-47078, Revised February 2013.

rich areas and resources in the rest of the grid that can be used to balance variances in renewable generation output.[205]

B.6 Estimating the Additional Benefits of Reducing the Frequency and Cost of Cycling Power Plants

With increased power production from intermittent renewable resources, some conventional generation units may be required to operate at their minimum operating levels and cycle up and down more frequently to accommodate the variability of intermittent resources on the system. Additional cycling of plants can be particularly pronounced when considering the uncertainties related to renewable generation that can lead to over-commitment and over-generation conditions during low loads periods. Such uncertainty-related over-generation conditions lead to excessive up/down and on/off cycling of generating units. The increased cycling of aging generating units may reduce their reliability, and the generating plants that are asked to shut down during off-peak hours may not be available for the following morning ramp and peak load periods, reducing the operational flexibility of the system. Some of these operational issues could reduce resource adequacy and increase market prices when the system must dispatch higher-cost resources.

Transmission investments can provide benefits by reducing the need for cycling fossil fuel power plants by spreading the impact of intermittent generation across a wider geographic region. Such projects provide access to a broader market and a wider set of generation plants to respond to the changes in generation output of renewable generation.

The cost savings associated with the reduction in plant cycling would vary across plants. A recent study of power plants in the Western U.S. found that increased cycling can increase the plants' maintenance costs and forced outage rates, accelerate heat rate deterioration, and reduce the lifespan of critical equipment and the generating plant overall. The study estimated

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[205] For a simplified framework to consider both short-term and long-term uncertainties in the context of transmission and renewable generation investments, see F. D. Munoz, B. F. Hobbs, J. Ho, and S. Kasina, "*An Engineering-Economic Approach to Transmission Planning Under Market and Regulatory Uncertainties: WECC Case Study*," Working Paper, JHU, March 2013;
A. H. Van Der Weijde, B. F. Hobbs, "*The Economics of Planning Electricity Transmission to Accommodate Renewables: Using Two-Stage Optimisation to Evaluate Flexibility and the Cost of Disregarding Uncertainty*," *Energy Economics*, 34(5). 2089-2101.
H. Park and R. Baldick, "Transmission Planning Under Uncertainties of Wind and Load: Sequential Approximation Approach," *IEEE Transactions on Power Systems*, vol. PP, no.99, March 22, 2013 pp1–8.

that the total hot-start costs for a conventional 500 MW coal unit are about $200/MW per start (with a range between $160/MW and $260/MW). The costs associated with equipment damage account for more than 80% of this total.[206]

Production cost simulations can be used to measure the impact of transmission investments on the frequency and cost of cycling fossil fuel power plants. However, the simplified representation of plant cycling costs in traditional production cost simulations—in combination with deterministic modeling that does not reflect many real-world uncertainties—will not fully capture the cycling-related benefits of transmission investments. Although SPP's Metrics Task Force recently suggested that production simulations be developed and tested,[207] this is an area where standard analytical methodology still needs to be developed.

B.7 Estimating the Additional Benefits of Reduced Amounts of Operating Reserves

Traditional production cost simulations assume that a fixed amount of operating reserves is required throughout the year, irrespective of transmission investments. Most market simulations set aside generation capacity for spinning reserves; regulation-up requirements may be added to that. Regulation-down requirements and non-spinning reserves are not typically considered. Such simplifications will understate the costs or benefits associated with any changes in ancillary service requirements. The analyses typically disregard the costs that integrating additional renewable resources may impose on the system or the potential benefits that transmission facilities can offer by reducing the quantity of ancillary services required. Such costs and benefits will become more important with the growth of variable renewable generation.

The estimation of these benefits consequently requires an analysis of the quantity and types of ancillary services at various levels of intermittent renewable generation, with and without the contemplated transmission investments. The Midwest ISO recently performed such an analysis,

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[206] N. Kumar, *et al.*, Power Plant Cycling Costs, AES 12047831-2-1, prepared by Intertek APTECH for National Renewable Energy Laboratory and Western Electricity Coordinating Council, April 2012. The study is based on a bottom-up analysis of individual maintenance orders and failure events related to cycling operations, combined with a top-down statistical analysis of the relationship between cycling operations and overall maintenance costs. See *Id.* (2011), p 14. Costs inflated from $2008 to $2012. Note that the Intertek-APTECH's 2012 study prepared for NREL (Kumar, *et al.*, 2012) reported only 'lower-bound' estimates to the public.

[207] Southwest Power Pool (SPP), *Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012,, Section 9.4.

finding that its portfolio of multi-value transmission projects reduced the amount of operating reserves that would have to be held within individual zones, which allowed reserves to be sourced from the most economic locations. MISO estimated that this benefit was very modest, with a present value of $28 to $87 million, or less than one percent of the cost of the transmission projects evaluated.[208] In other circumstances, where transmission can interconnect regions that require additional supply of ancillary services with regions rich in resources that can provide ancillary services at relatively low costs (such as certain hydro-rich regions), these savings may be significantly larger. However, to quantify these benefits may require specialized (but available) simulation tools that can simulate both the impacts of imperfect foresight and the costs of intra-hour load following and regulation requirements.[209] Most production cost simulations are limited to simulating market conditions with perfect foresight and on an hourly basis.

FIGURE 15. DELIVERABILITY CAPACITY NEEDS AT 40% RENEWABLE ENERGY

Source: MISO, *MISO's Renewable Integration Impact Assessment (RIIA)*, Summer Report, February 2021, p 99.

Finally, a number of organized power markets do not co-optimize the dispatch of energy and ancillary services resources. Other regions with co-optimized markets may still require some location-specific unit commitment to provide ancillary services. If not considered in market simulations, this can understate the potential benefits associated with transmission-related congestion relief.

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[208] Midwest ISO, *Proposed Multi Value Project Portfolio*, Technical Study Task Force and Business Case Workshop, August 22, 2011. , pp 29-33.

[209] For an example of the quantification of these benefits, see Pfeifenberger, Ruiz, Van Horn, The Value of Diversifying Uncertain Renewable Generation through the Transmission System, BU-ISE, October 14, 2020.

B.8 Estimating the Benefits of Mitigating Reliability Must-Run Conditions

Traditional production cost simulation models determine unit commitment and dispatch based on first contingency transmission constraints, utilizing a simple direct current (DC) power-flow model. This means that the simulation models will not by themselves be able to determine the extent to which generation plants would need to be committed for certain local reliability considerations, such as for system stability and voltage support and to avoid loss of load under second system contingencies. Instead, any such "reliability must run" (RMR) conditions must be identified and implemented as a specific simulation input assumption. Both existing RMR requirements and the reduction in these RMR conditions as a consequence of transmission upgrades need to be determined and provided as a modeling input separately for the Base Case and Change Case simulations.

RMR-related production cost savings provided by transmission investments can be significant. For example, a recent analysis of transmission upgrades into the New Orleans region shows that certain transmission projects would significantly alleviate the need for RMR commitments of several local generators. Replacing the higher production costs from these local RMR resources with the market-based dispatch of lower-cost resources resulted in estimated annual production cost savings ranging from approximately $50 million to $100 million per year.[210] Avoiding or eliminating a set of pre-existing RMR requirements needed to be specified as model input assumptions.

B.9 Estimating Production Costs in "Day-1" Markets

When analyzing transmission benefits in bilateral, non-RTO markets, it is important to recognize that generation unit commitment and dispatch in such "Day-1" markets is not the same as in an LMP-based RTO market. Thus, if simulated as security-constrained LMP-based regional markets, the simulations would understate the benefit of transmission investments in non-RTO markets by over-optimizing the system operations compared to real-world outcomes. To recognize some of the realities of such "Day-1" markets, planners have traditionally imposed "hurdle rates" on transactions between individual balancing areas. This is important to prevent the simulations from over-optimizing system dispatch relative to actual market outcomes. However, relying solely on hurdle rates to approximate realistic market outcomes may not be

[210] Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 et al., September 24, 2012.

sufficient. Thus, derates of transmission limits may also be necessary to capture the fact that congestion management through transmission loading relief (TLR) processes in "Day-1" markets typically results in under-utilization of flow-gate limits. For example, an analysis of RTO-market benefits by the Department of Energy (DOE) assumed that improved congestion management and internalization of power flows by ISOs result in a 5–10% increase in the total transfer capabilities on transmission interfaces.[211] Similarly, a study of congestion management in MISO's "Day-1" market found that, during 2003, available flowgate capacities were underutilized by between 7.7% to 16.4% on average within MISO subregions during TLR events compared to the flows that could have been accommodated had the grid been efficiently dispatched using a regional security-constrained economic dispatch.[212]

We recommend that "Day-1" market simulations use both hurdle rates and derates to more realistically approximate actual market conditions (in both base and change case simulations). Hurdle rates as traditionally used will appropriately decrease flows between balancing areas, reduce congestion, and thus reduce the economic value of increased transmission between balancing areas. In contrast, derates will tend to simulate more realistic level of congestion within and across balancing areas, which will tend to increase the estimated production cost savings of transmission upgrades. These potential additional production cost savings will not be captured in traditional market simulations that rely solely on hurdle rates to approximate "Day-1" market conditions.

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[211] U.S. Department of Energy, Report to Congress, *Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design*, DOE/S-0138, April 30, 2003, pp 7-8 and 41-42.

[212] R.R. McNamara, Affidavit on behalf of Midwest ISO before the Federal Energy Regulatory Commission, Docket ER04-691-000, on June 25, 2004, p 14.

Appendix C – Other Potential Project-Specific Benefits

Some transmission investments can create additional benefits that are very specific to the particular set of projects. These benefits may include improved storm hardening, increased loadserving capability, synergies with future transmission projects, the option value of large transmission facilities to improve future utilization of available transmission corridors, fuel diversity and resource planning flexibility, increased wheeling revenues, and the creation of additional physical or financial transmission rights to improve congestion hedging opportunities. Below, we discuss each briefly.

C.1 Storm Hardening and Wildfire Resilience

In regions that experience storm- or wild-fire induced transmission outages, certain transmission upgrades can improve the resilience of the existing grid transmission system. Strong storms that damage transmission lines can drastically affect an entire region where production cost impacts and the value of lost load can be very large. Even if new transmission lines intended to increase system resilience are built along similar routes as existing transmission lines (and thus seemingly can be damaged by the same natural disasters), newer technologies and construction standards would allow the new projects to offer greater storm resilience than the existing transmission lines.[213] Adding transmission on geographically sufficiently separate rights of ways will mitigate risks even if each of the transmission paths face equal risks of storm or wild-fire induced outages.

C.2 Increased Load Serving Capability

A transmission project's ability to increase future load-serving capability ahead of specific transmission service requests is usually not considered when evaluating transmission benefits. For example, in regions experiencing significant load growth, the existing electric system often requires costly and possibly time-consuming system upgrades when a new industrial or commercial customer with a significant amount of load is contemplating locating in a utility's service area. At times, new transmission lines built to serve other needs (such as to increase

[213] Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 79–80.

market efficiency or to meet public-policy objectives) can also create low-cost options to quickly increase load-serving capability in the future.[214]

C.3 Synergies with Future Transmission Projects and Asset Replacement Needs

Certain transmission projects provide synergies with future transmission investments. For example, the building of the Tehachapi transmission project to access 4,500 MW of wind resources in the CAISO provides the option for a lower-cost upgrade of Path 26 than would otherwise be possible, as well as additional options for future transmission expansions in that region.[215] Planning a set of "no-regrets" projects that will be needed under a wide range of future market conditions can help capitalize on such "option value." For instance, the RITELine Project (spanning from western Illinois to Ohio) provides a "no regrets" step toward the creation of a larger regional transmission overlay that can integrate the substantial amount of renewable generation needed to meet the regional states' RPS requirements over the next 10 to 20 years.[216] A number of regional planning efforts (such as RGOS I, RGOS II, and SMART) have shown that the expansion of renewable generation over the next 20 years may require construction of a Midwest-wide regional transmission overlay. The RITELine Project is an element common to the transmission configurations recommended in each of these larger regional transmission studies and, thus, in addition to the project's standalone merit, creates the option of becoming an integrated part of such a regional overlay. Because the project is both valuable on a stand-alone basis and can be used as an element of the larger potential regional overlays, it can be seen as a first step that provides the option for future regional transmission buildout. Finally, as discussed in the main body of this report, New York's Public Policy Transmission Projects, built on the right of way of aging transmission facilities that would need to be replaced within the next decade, offer significant cost savings by avoiding having to replace the aging facilities in the future.[217] These benefit of synergies with the replacement of aging facilities on scarce and valuable rights of way is particularly important because as PJM explains, for example:

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[214] For example, see *id.*, p 80.

[215] California ISO, *Transmission Economic Assessment Methodology (TEAM)*, June 2004, pp 9–21. Tehachapi region referred to as Kern County.

[216] Pfeifenberger and S. A. Newell, Direct Testimony, FERC Docket No. ER11-4069-000 (RITELine), filed July 18, 2011.

[217] Newell, *et al.*, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, September 15, 2015.

> The regional high-voltage transmission system is aging. Many facilities were placed in service in the 1960s or earlier and are deteriorating and reaching the end of their useful lives. Within PJM, nearly two-thirds of all bulk electric system assets are more than 40 years old and more than one third are more than 50 years old. Some local lower-voltage equipment, especially below 230 kV, is approaching 90 years old.[218]

C.4 Up-Sizing Lines and Improved Utilization of Available Transmission Corridors

The number of right-of-way "corridors" on which new transmission lines can be built is often extremely limited, particularly in heavily populated or environmentally sensitive areas. As a result, constructing a new line on a particular right-of-way may limit or foreclose future options of building a higher-capacity line or additional lines. Foreclosing that option can turn out to be very costly. It will often be possible, however, to preserve this option or reduce the cost of foreclosing that option through the design of the transmission line that is planned and constructed now. For example, "upsizing" a transmission line ahead of actual need (*e.g.*, to a double-circuit or higher-voltage line) requires incremental investment but will greatly reduce the cost of foreclosing the option to increase capacity along the same corridor when additional transfer capability would be needed in the future. Similarly, the option to increase transmission capabilities in the future can be created, for example, by building a single-circuit line on double-circuit towers that create the option to add a second circuit in the future. Building a line rated for a higher voltage level than the voltage level at which it is initially operated (*e.g.*, building a line with 765kV equipment that is initially operated only at 345kV) creates the option to increase the transfer capability of the line at modest incremental costs in the future. While investing more today to create such low-cost options to "up-size" lines in the future may be valuable even without right of way limits, this option will be particularly valuable if finding additional right of ways would be very difficult or expensive.

[218] PJM "*The Benefits of the PJM Transmission System*" PJM Interconnection at 5 (April 16, 2019). See also see also Affidavit of Johannes P. Pfeifenberger and John Michael Hagerty in FERC Docket ER20-2308-000, on behalf of LS Power, July 23, 2020.

C.5 Increased Fuel Diversity and Resource Planning Flexibility

Transmission upgrades sometimes can help interconnect areas with very different resource mixes, thereby diversifying the fuel mix in the combined region and reducing price and production cost uncertainties. Projects also can provide resource planning flexibility by strengthening the regional power grid and lowering the cost of addressing future uncertainties, such as changes in the relative fuel costs, public policy objectives, coal plant retirements, or natural gas delivery constraints.

C.6 Benefits Related to Relieving Constraints in Fuel Markets

Additional transmission lines can provide benefits associated with relieving constraints in fuel markets. For example, recent reliability concerns in New England concerning gas-electric coordination issues caused by the increasing reliance on natural gas fired generation and limitations on pipeline capacity could be alleviated by additional import capacity for wholesale power from outside New England. In addition, increased diversity of generation resources enabled by new transmission lines can reduce the demand and price of fuel.[219]

C.7 Increased Wheeling Revenues

As mentioned in the context of interregional cost allocation, a transmission line that increases exports (or wheeling through) of low-cost generation to a neighboring region can provide additional benefits to the exporting region's customers through increased wheeling out revenues. The increase in wheeling revenues, paid for by the exporting generator or importing buyer, will offset a portion of the transmission projects' revenue requirements, thus reducing the net costs to the region's own transmission customers. While not an economy-wide benefit, increasing a transmission owner's wheeling revenues is equivalent to allocating some of the project costs to exporters and/or neighboring regions. For example, our analysis of an illustrative portfolio of transmission projects in the Entergy region estimated that approximately $400 million of potential resource adequacy benefits were realized from

[219] V. Budhraja, J. Balance, J. Dyer, and F. Mobasher, *Transmission Benefit Quantification, Cost Allocation and Cost Recovery*, Final Project Report prepared for CIEE by Lawrence Berkeley National Laboratory and CERTS, Proj. Mgr. J. Eto, June 2008, pp 43-44.

deferred generation investment needs in the TVA service area by exporting additional amounts of surplus capacity from merchant generators in the Entergy region. While this is a benefit that accrues in large part to TVA customers and merchant generators in the Entergy region, approximately $130 million of the $400 million benefits accrue to Entergy and MISO customers in the form of additional MISO wheeling revenues after Entergy joins MISO, which partially offset the transmission projects' revenue requirements that would need to be recovered from Entergy/MISO customers and other market participants.[220] SPP has also estimated that the additional export capability created by its portfolio of ITP projects increases SPP wheeling-out revenues, which offsets the present value of its transmission revenue requirements by over $600 million, thereby offsetting a meaningful portion of the costs of SPP regional transmission project, even though these projects were not specifically planned to increase export capability.[221]

C.8 Increased Transmission Rights and Customer Congestion-Hedging Value

A transmission project that increases transfer capabilities between lower-cost and higher-cost regions of the power grid can provide customer benefits by providing access in the form of increasing the availability of physical transmission rights in non-RTO markets or across RTO boundaries. Within RTOs, the transmission upgrade would increase financial transmission rights that can be requested by and allocated to load-serving entities. The availability of additional FTRs increases the proportion of congestion charges that can be hedged by LSEs, thereby reducing congestion-related uncertainty. The additional FTRs can also reduce an area's customer costs by allowing imports from lower-cost portions of the region.[222] While a transmission upgrade may result in increased FTR revenues to LSEs from additional FTRs, the customer benefit of these additional revenues tends to be offset by revenue decreases from existing FTRs because the project will reduce congestion charges (and therefore reduce revenues from existing FTRs). For example, our analysis of the congestion and FTR-related impacts for the Paddock-Rockdale project in Wisconsin showed that these customer impacts

[220] For example, see Pfeifenberger, Direct Testimony on behalf of ITC Holdings, Exhibit No. ITC-600, before the Federal Energy Regulatory Commission, Docket Nos. EC12-145 *et al.*, September 24, 2012, pp 73-76.

[221] SPP, *RCAR 2 Report* (spp.org), July 11, 2016, Figure 7.1

[222] As noted earlier, this benefit is not captured in the traditional adjusted production cost (APC) and Load LMP metrics, because the metrics assume that all imports are priced at the load's location (*i.e.*, the area-internal Load LMP).

can range widely—from increasing traditional APC estimates by approximately 50% in scenarios with low APC savings to decreasing traditional APC estimates by approximately 35% in scenarios with high APC savings.[223]

C.9 Operational Benefits of High-Voltage Direct-Current Transmission Lines

The addition of high-voltage direct-current ("HVDC") transmission lines can provide a range of operational benefits to system operators by enhancing reliability and reducing the cost of system operations. These operational benefits of HVDC lines, which in large part stem from the projects' new converter technologies, are broadly recognized in the industry. For example, various authors note that the technology can be used to: (1) provide dynamic voltage support to the AC system, thereby increasing its transfer capability;[224] (2) supply voltage and frequency support;[225] (3) improve transient stability[226] and reactive performance;[227] (4) provide AC system damping;[228] (5) serve as a "firewall" to limit the spread of system disturbances;[229] (6) "decouple" the interconnected system so that faults and frequency variations between the wind farms and the AC network or between different parts of the AC network do not affect each other;[230] and (7) provide blackstart capability to re-energize a 100% blacked-out portion of

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223 Pfeifenberger, Direct Testimony on behalf of American Transmission Company, before the Public Service Commission of Wisconsin, Docket 137-CE-149, January 17, 2008, Appendix A.

224 M. P. Bahrman, "HVDC Transmission Overview," *Transmission and Distribution Conference and Exposition, 2008*. T&D. IEEE/PES, April 21-24, 2008), p 5.

225 S. Wang, J. Zhu, L. Trinh, and J Pan, "Economic Assessment of HVDC Project in Deregulated Energy Markets," *Electric Utility Deregulation and Restructuring and Power Technologies*, 2008. DRPT 2008. IEEE Third International Conference, pp18, 23, 6-9 April 2008, p 19.

226 Institute of Electrical and Electronics Engineers (IEEE) Power & Energy Society (PES), *HVDC Systems & Trans Bay Cable*, presentation, March 16, 2005, p 75.

227 As noted in several sources including: (1) University of Maryland Center for Integrative Environmental Research, *Maryland Offshore Wind Development: Regulatory Environment, Potential Interconnection Points, Investment Model, and Select Conflict Areas*, October 2010, p 51; (2) European Wind Energy Association, *Oceans of Opportunity: Harnessing Europe's Largest Domestic Energy Resource*, September 2009, p 27; and (3) S. D. Wright, A. L. Rogers, J. F. Manwell, A> Ellis, "Transmission Options for Offshore Wind Farms in the United States," in Proceedings of the American Wind Energy Association (AWEA) Annual Conference, 2002, p 5.

228 Institute of Electrical and Electronics Engineers (IEEE) Power & Energy Society, *HVDC Systems & Trans Bay Cable*, presentation, March 16, 2005, p 75.

229 Siemens, "HVDC PLUS (VSC Technology): Benefits," n.d. .

230 L. P. Lazaridis, *Economic Comparison of HVAC and HVDC Solutions for Large Offshore Wind Farms under Special Consideration of Reliability*, Master's Thesis X-ETS/ESS-0505, Royal Institute of Technology Department of Electrical Engineering, 2005, p 34.

the network.[231] For example, PJM recognized these benefits in its evaluation of the HVDC option for the Mid-Atlantic Power Pathway project.[232] It was also found that the proposed Atlantic Wind Connection HVDC submarine project's ability to redirect flow instantaneously will provide PJM with additional flexibility to address reliability challenges, system stability, voltage support, improved reactive performance, and blackstart capability.[233]

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[231] As noted in several sources including: (1) University of Maryland Center for Integrative Environmental Research, Maryland Offshore Wind Development: Regulatory Environment, Potential Interconnection Points, Investment Model, and Select Conflict Areas, October 2010, p 51; (2) European Wind Energy Association, Oceans of Opportunity: Harnessing Europe's Largest Domestic Energy Resource, September 2009, p 27; and (3) S. D. Wright, A. L. Rogers, J. F. Manwell, A. Ellis, "Transmission Options for Offshore Wind Farms in the United States," in Proceedings of the American Wind Energy Association (AWEA) Annual Conference, 2002, p 5.

[232] PJM Interconnection, "2008 RTEP — Reliability Analysis Update," Transmission Expansion Advisory Committee (TEAC) Meeting, October 15, 2008, pp 8-10.

[233] Pfeifenberger and S. A. Newell, Direct Testimony on behalf of The AWC Companies, before the Federal Energy Regulatory Commission, Docket No. EL11-13-000, December 20, 2010.

Appendix D – Approaches Used to Quantify Transmission Benefits

(Source: 2013 Brattle report for WIRES[234])

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
1. Traditional Production Cost Savings – See Section IV.2.				
2. Additional Production Cost Savings				
--	Reduced impact of forced generation outages	Consideration of both planned and forced generation outages will increase impact	Consider both planned and (at least one draw of) forced outages in market simulations.	Already considered in most (but not all) RTOs
a.	Reduced transmission energy losses	Reduced energy losses incurred in transmittal of power from generation to loads reduces production costs	Either (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for range of hours; or (3) estimate how cost of supplying losses will likely change with marginal loss charges	CAISO (PVD2) ATC Paddock-Rockdale SPP (RCAR)
b.	Reduced congestion due to transmission outages	Reduced production costs during transmission outages that significantly increase transmission congestion	Introduce data set of normalized outage schedule (not including extreme events) into simulations or reduce limits of constraints that make constraints bind more frequently	SPP (RCAR) RITELine
c.	Mitigation of extreme events and system contingencies	Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, or multiple outages.	Calculate the probability-weighed production cost benefits through production cost simulation for a set of extreme historical market conditions	CAISO (PVD2) ATC Paddock-Rockdale
d.	Mitigation of weather and load uncertainty	Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns	Use SPP suggested modeling of 90/10 and 10/90 load conditions as well as scenarios reflecting common regional weather patterns	SPP (RCAR)
e.	Reduced costs due to imperfect foresight of real-time conditions	Reduced production costs during deviations from forecasted load conditions, intermittent resource generation, or plant outages	Simulate one set of anticipated load and generation conditions for commitment (*e.g.*, day ahead) and another set of load and generation conditions during real-time based on historical data	
f.	Reduced cost of cycling power plants	Reduced production costs due to reduction in costly cycling of power plants	Further develop and test production cost simulation to fully quantify this potential benefit ; include long-term impact on maintenance costs	WECC study

[234] Chang, Pfeifenberger, and Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, prepared for WIRES, July 2013.

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
g.	Reduced amounts and costs of ancillary services	Reduced production costs for required level of operating reserves	Analyze quantity and type of ancillary services needed with and without the contemplated transmission investments	NTTG WestConnect MISO MVP
h.	Mitigation RMR conditions	Reduced dispatch of high-cost RMR generators	Changes in RMR determined with external model used as input to production cost simulations	ITC-Entergy CAISO (PVD2)
i.	More realistic representation of system utilization in "Day-1" markets	Transmission offers higher benefits if market design is utilizing the existing grid less efficiently	Use flowgate derates (in addition to the traditional use of hurdle rates between balancing areas) in production cost simulations to more realistically approximate system utilization in "Day-1" markets	MISO "Day-2" Market benefit analysis
3–4. Reliability and Resource Adequacy Benefits and Generation Capacity Cost Savings				
Transmission Benefit		**Benefit Description**	**Approach to Estimating Benefit**	**Examples**
3. Reliability and Resource Adequacy Benefits				
a.	Avoided or deferred reliability projects	Reduced costs on avoided or delayed transmission lines otherwise required to meet future reliability standards	Calculate present value of difference in revenue requirements of future reliability projects with and without transmission line, including trajectory of when lines are likely to be installed	ERCOT All RTOs and non-RTOs ITC-Entergy analysis MISO MVP
b.	Reduced loss of load probability <u>Or</u>:	Reduced frequency of loss of load events (if planning reserve margin is not changed despite lower LOLEs)	Calculate value of reliability benefit by multiplying the estimated reduction in Expected Unserved Energy (MWh) by the customer-weighted average Value of Lost Load ($/MWh)	SPP (RCAR)
c.	Reduced planning reserve margin	Reduced investment in capacity to meet resource adequacy requirements (if planning reserve margin is reduced)	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to reduced resource adequacy requirements	MISO MVP SPP (RCAR)
4. Generation Capacity Cost Savings				
a.	Capacity cost benefits from reduced peak energy losses	Reduced energy losses during peak load reduces generation capacity investment needs	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to capacity savings from reduced energy losses	ATC Paddock-Rockdale MISO MVP SPP ITC-Entergy
b.	Deferred generation capacity investments	Reduced costs of generation capacity investments through expanded import capability into resource-constrained areas	Calculate present value of capacity cost savings due to deferred generation investments based on Net CONE or capacity market price data	ITC-Entergy

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
c.	Access to lower-cost generation	Reduced total cost of generation due to ability to locate units in a more economically efficient location	Calculate reduction in total costs from changes in the location of generation attributed to access provided by new transmission line	CAISO (PVD2) MISO ATC Paddock-Rockdale

5–6. Market, Environmental and Public Policy

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
5. Market Benefits				
a.	Increased competition	Reduced bid prices in wholesale market due to increased competition amongst generators	Calculate reduction in bids due to increased competition by modeling supplier bid behavior based on market structure and prevalence of "pivotal suppliers"	ATC Paddock-Rockdale CAISO (PVD2, Path 26 Upgrade)
b.	Increased market liquidity	Reduced transaction costs and price uncertainty	Estimate differences in bid-ask spreads for more and less liquid markets; estimate impact on transmission upgrades on market liquidity	SCE (PVD2)
6. Environmental Benefits				
a.	Reduced emissions of air pollutants	Reduced output from generation resources with high emissions	Additional calculations to determine net benefit emissions reductions not already reflected in production cost savings	NYISO CAISO
b.	Improved utilization of transmission corridors	Preserve option to build transmission upgrade on an existing corridor or reduce the cost of foreclosing that option	Compare cost and benefits of upsizing transmission project (*e.g.*, single circuit line on double-circuit towers; 765kV line operated at 345kV)	
7.	**Public Policy Benefits**	Reduced cost of meeting policy goals, such as RPS	Calculate avoided cost of most cost-effective solution to provide compliance to policy goal	ERCOT CREZ ISO-NE, CAISO MISO MVP SPP (RCAR)

CERTIFICATE OF SERVICE

I hereby certify that on this 12th day of October, 2021, a copy of the foregoing document has been electronically served upon each person designated on the official service list in this proceeding.

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