Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs

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NOTICE

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- 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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TABLE OF CONTENTS

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

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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.

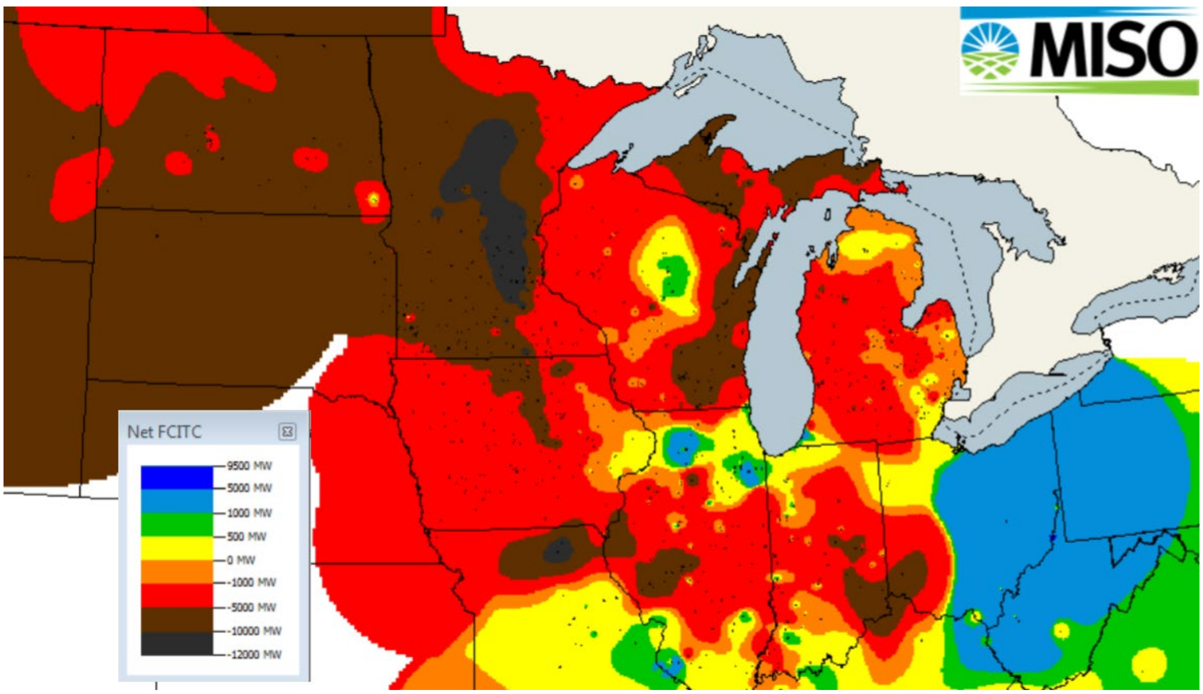
14 The MVP lines cost $6.57 billion, per MISO, *Regionally Cost Allocated Project Reporting Analysis, MVP Project Status July 2021*, and were designed to interconnect 15,949 MW of wind, per MISO, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the 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

[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

[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]

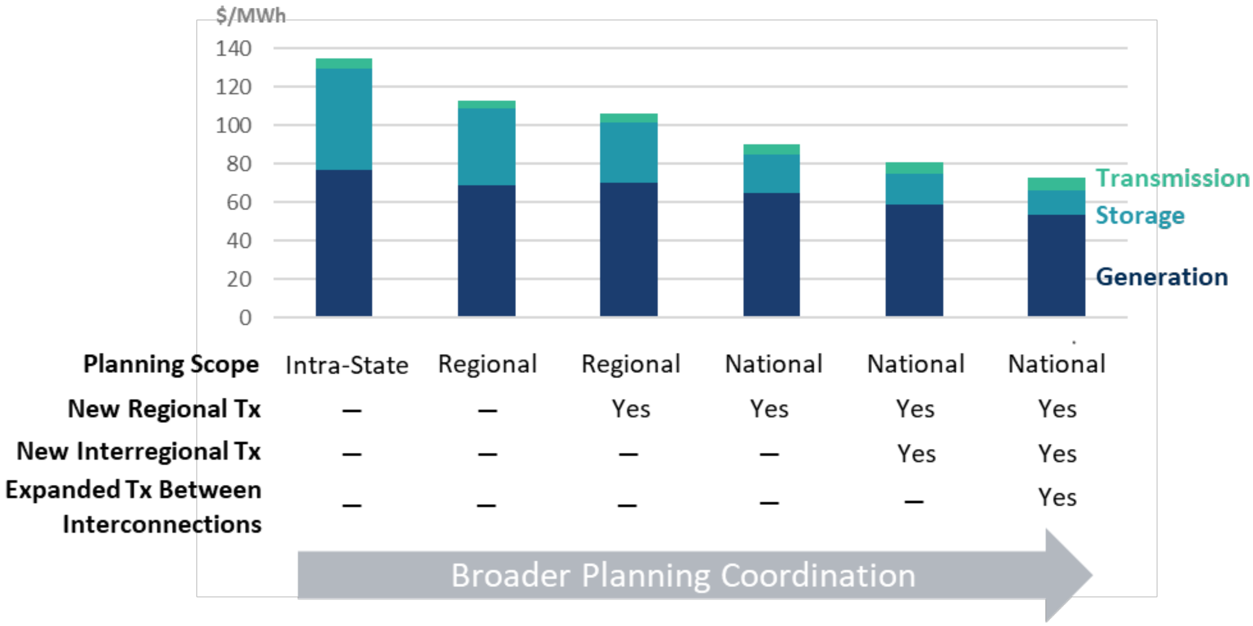
[25] P. R. Brown and A. Botterud, "*The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*," *Joule*, Vol. 5, No. 1, p115–134, January 20, 2021.

[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 Patrick 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 multi-value 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 scenario-based 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 portfolio-based 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 joint interregional 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

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[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.

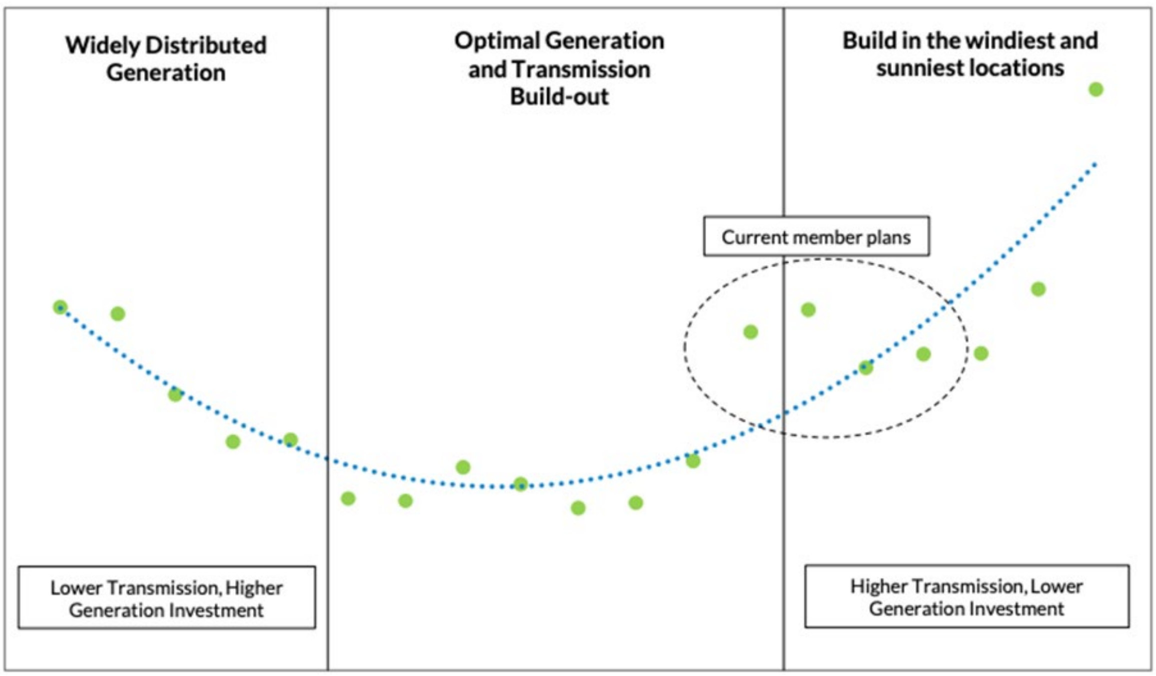
The MISO MVPs present another example of proactive forward-looking planning that resulted in transmission solutions that reduce system wide costs. The MVPs were the result of MISO's proactive planning effort prior to 2010, the Regional Generation Outlet Study (RGOS).[71] RGOS performed proactive planning 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

[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.

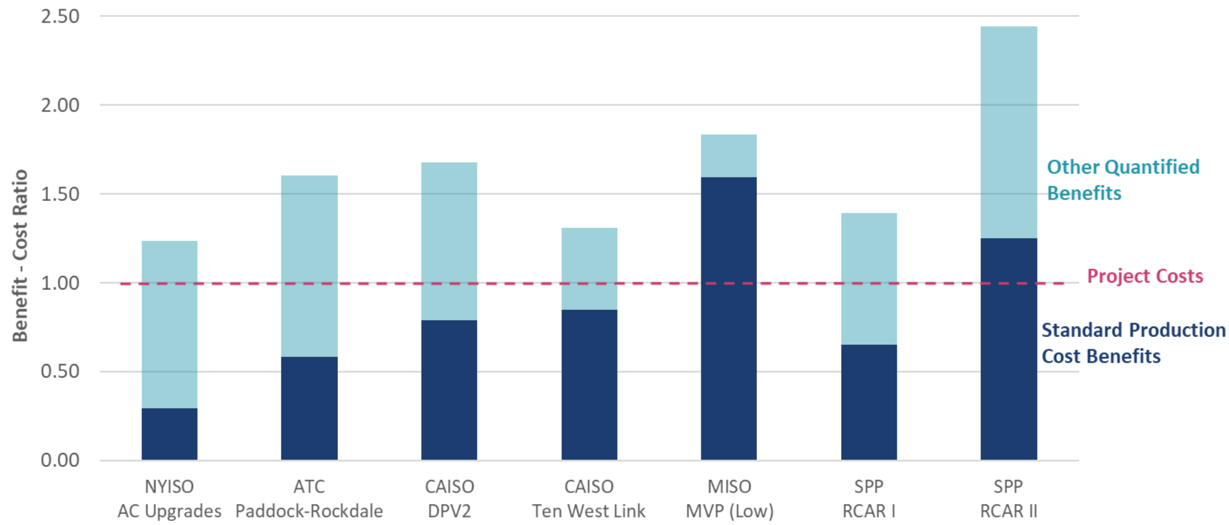
While not all proposed transmission investments provide benefits that exceed project costs, overlooking benefits because traditional tools and processes do not automatically capture these benefits leads to the premature rejection of valuable projects and underinvestment in transmission infrastructure. 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

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.

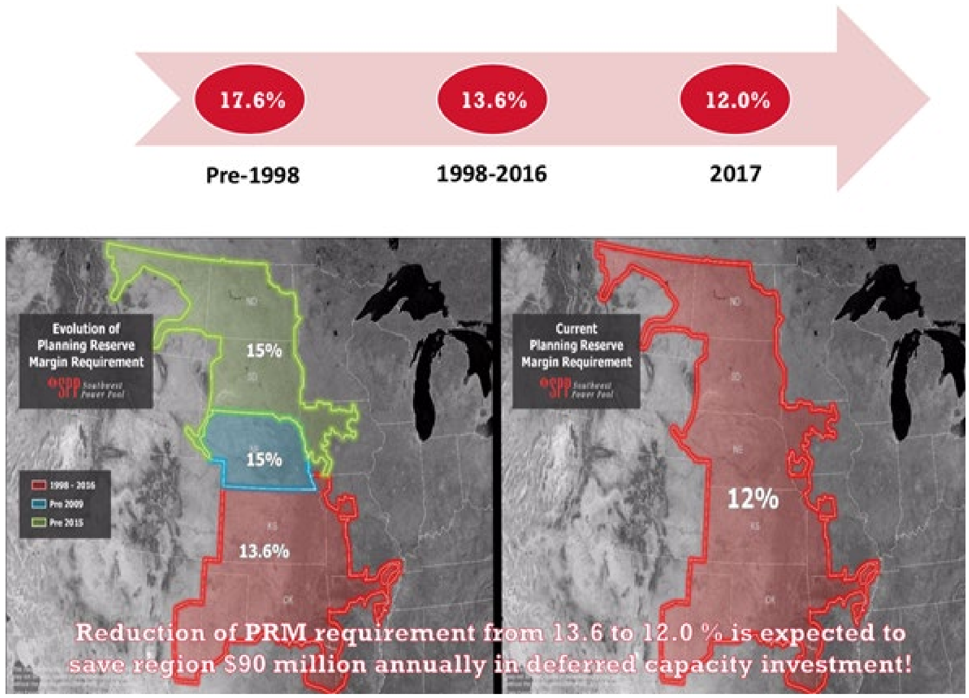
92 Public Service Commission (PSC) of Wisconsin (WI), *Order*, re Investigation on the Commission's Own Motion to Review the 18 Percent Planning Reserve Margin Requirement, Docket 5-EI-141, PSC REF#:102692, dated October 9, 2008, received October 11, 2008, p 5. Two other changes that contributed to this 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

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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

[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.

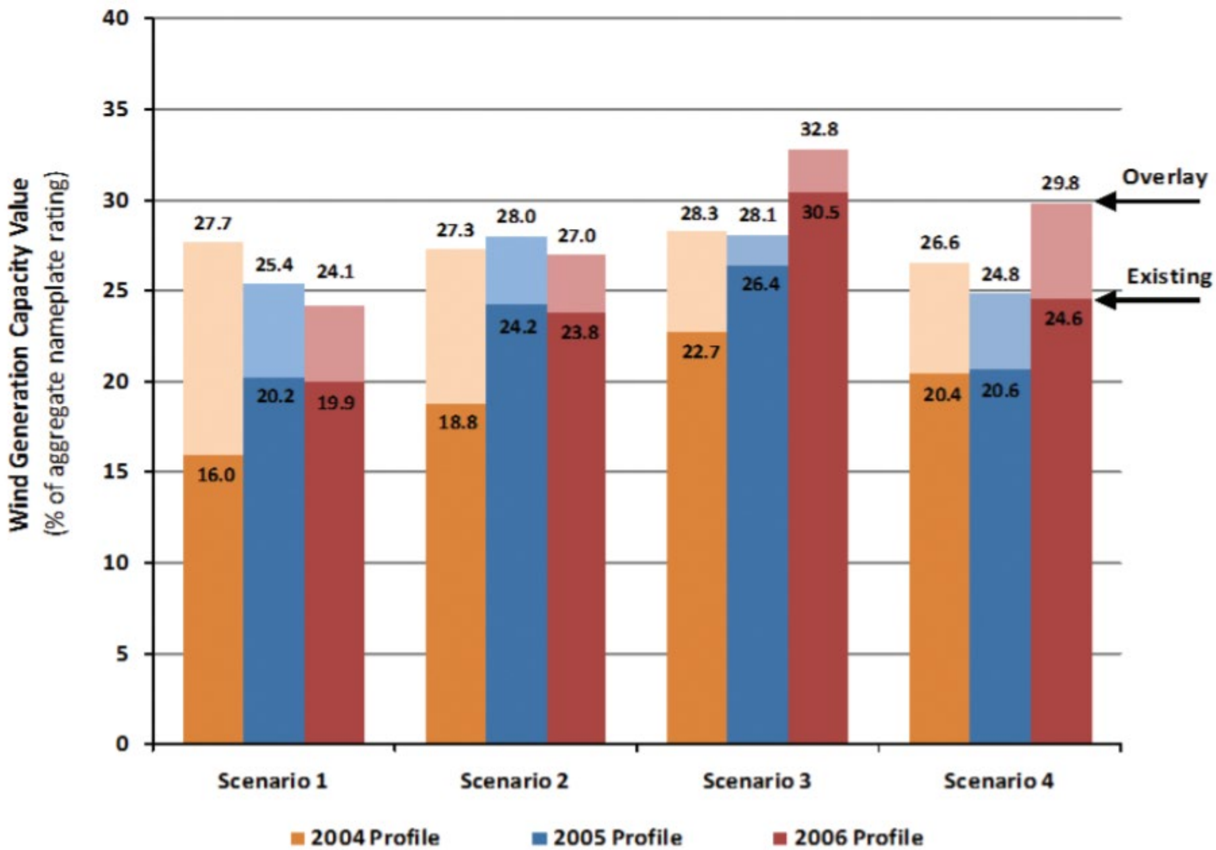
Transmission can increase the capacity value of existing resources, particularly wind and solar resources due to their geographic diversity. Higher capacity values reduce system (generation plus transmission) costs and increase net benefits. In the chart below from the Eastern Wind Integration and Transmission 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

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[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]

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[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

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

power and reduce overall market concentration. The overall magnitude of benefits from increased competition 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.

competition would offset between 10 to 40% of the project costs, depending on assumed market structure and supplier behavior.[115]

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

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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 (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

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 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.

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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.

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] 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

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[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.

[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.

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 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.

[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.

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.

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]

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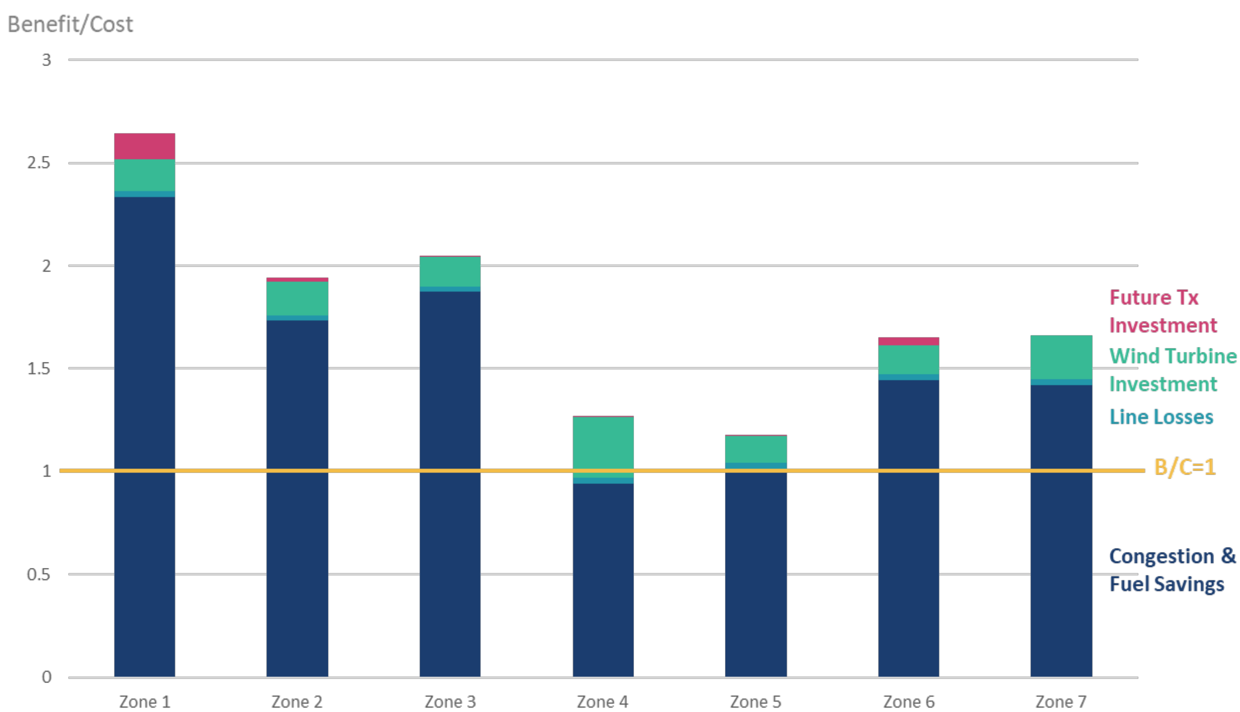
[124] Southwest Power Pool (SPP), *Regional Cost Allocation Review (RCAR II)*, July 11, 2016.

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 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.

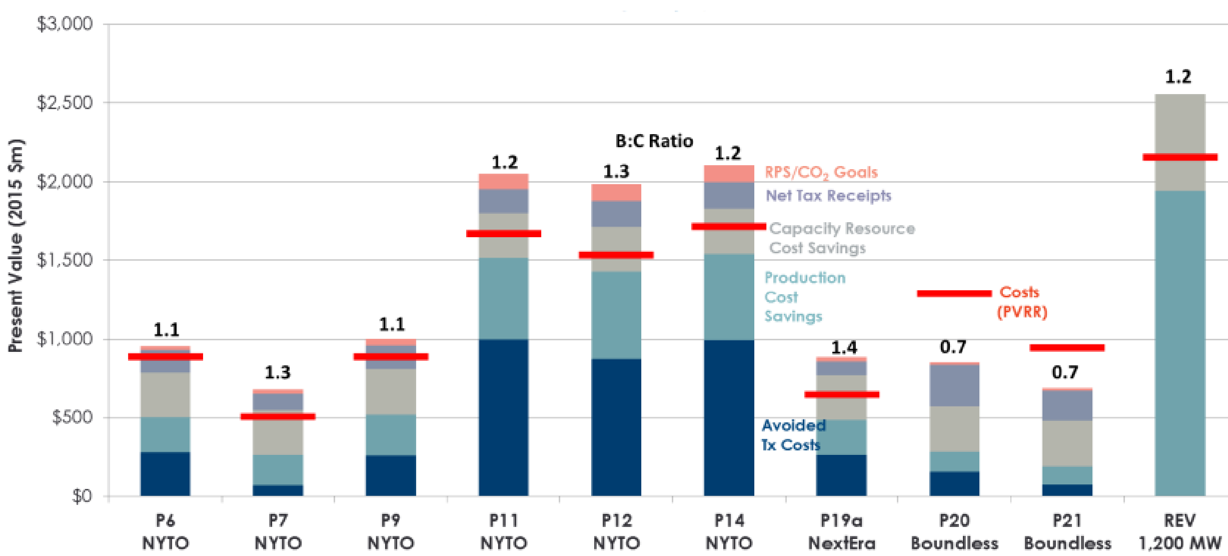
[125] MISO, *MTEP19 MVP Limited Review Report*, 2019.

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 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 Transmission 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)

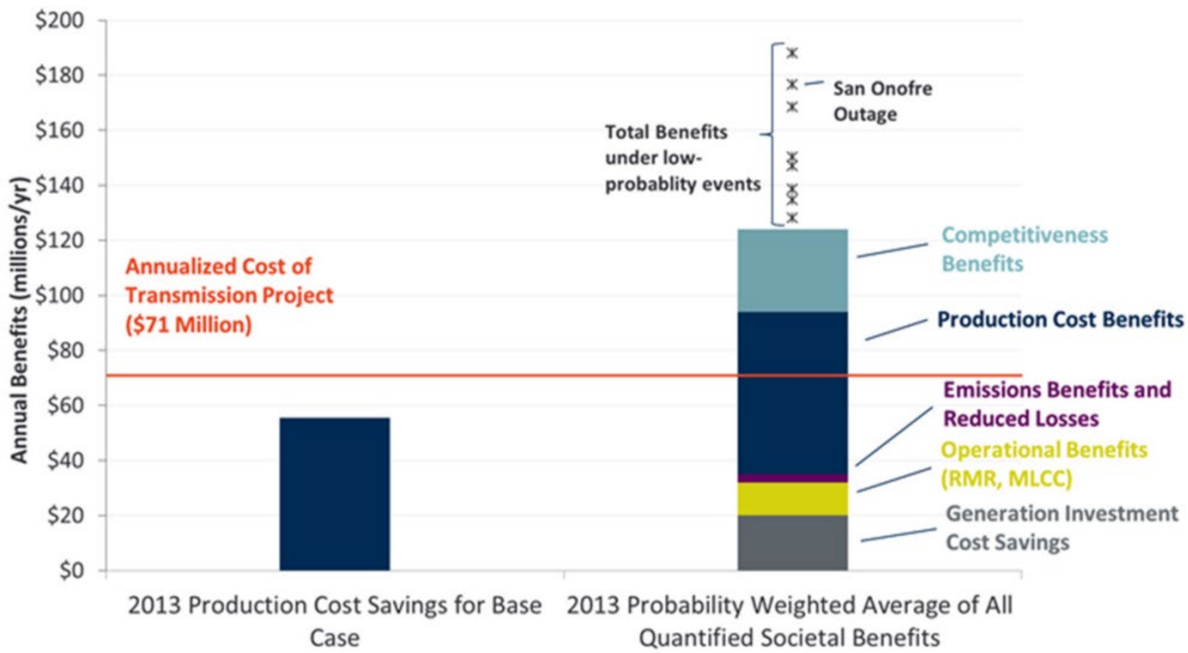
CAISO has occasionally utilized its TEAM approach in its transmission planning effort, which considers multiple benefits.[127] When initially evaluating CAISO's Palo Verde-Devers 2 (PVD2) line, the California Public Utility Commission (CPUC) relied on results from the TEAM approach.[128] Quantified benefits 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.

[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.

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[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.

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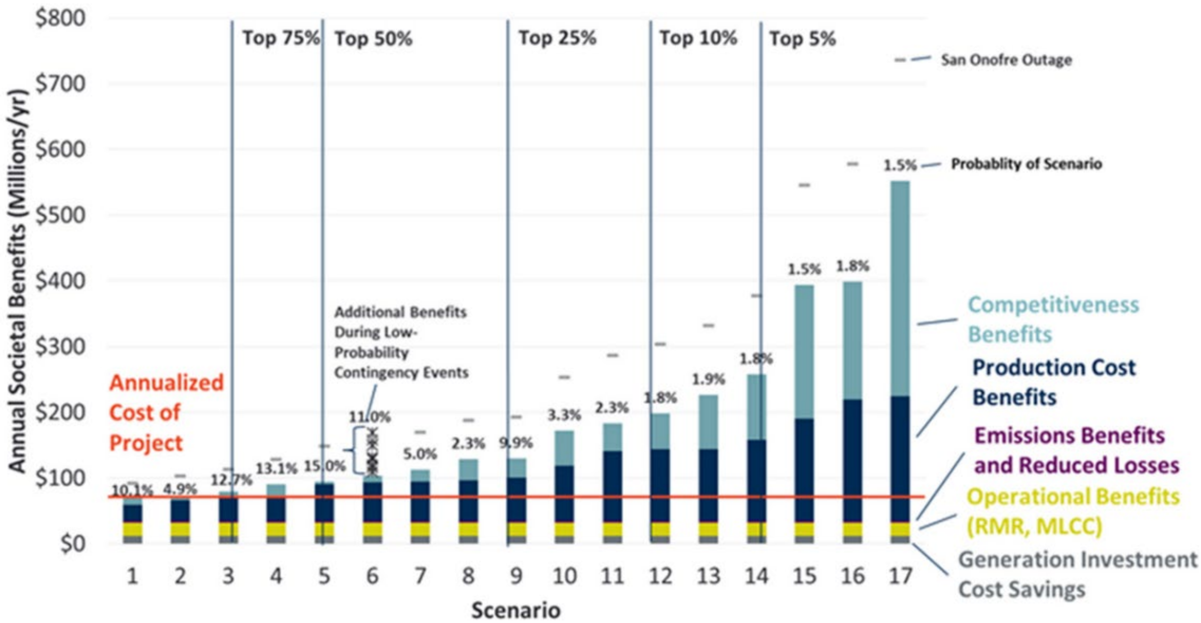
[135] California ISO (CAISO) Department of Market Analysis & Grid Planning, *Board Report: Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)*, February 24, 2005.

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.

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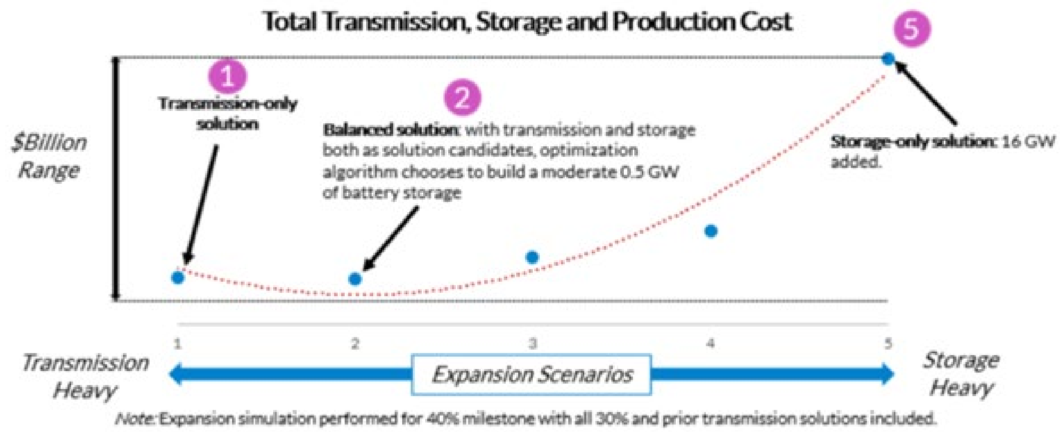
[136] J. Frayer, E. Wang, R. Wang, *et al.*(London Economics International, Inc.), *How Does Electric Transmission Benefit You?: Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investment*, A WIRES report, January 8, 2018, p 46.

[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.

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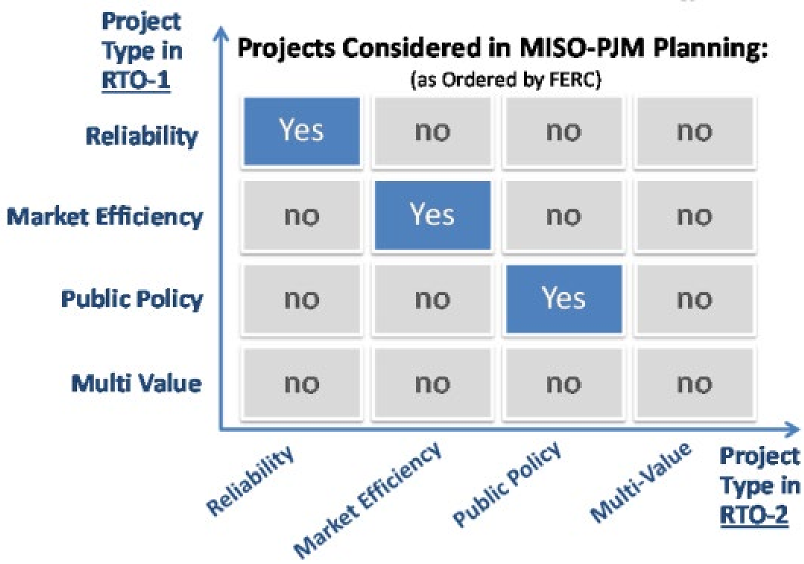
[141] This approach is widely used for infrastructure costs, such as roads or distribution systems. The portfolio-based approach has also been applied, for example, by SPP for the highway-byway cost allocation of projects approved through its Integrated Transmission Planning (ITP) process and MISO for 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

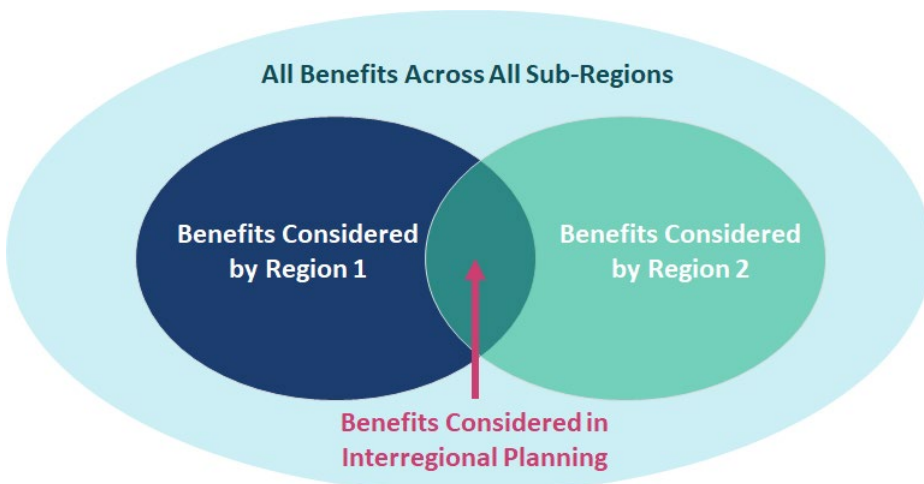


By focusing only on projects that address reliability, market efficiency, or public policy needs in both regions, the planning process inadvertently excludes any interregional projects that, for example, would address reliability needs in one region but address market efficiency or public policy needs 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]	✓	✓	✓	✓	✓

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]

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[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]

[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.

[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

[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,

[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.

[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.

[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]

[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 Or:	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)