Multi-Value Transmission Planning for a Clean Energy Future

Report by the Energy Systems Integration Group's Transmission Benefits Valuation Task Force

June 2022

ESIG
ENERGY SYSTEMS INTEGRATION GROUP

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A Report of the Energy Systems Integration Group's Transmission Benefits Valuation Task Force

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List of Abbreviations

CAISO	California Independent System Operator
CONE	Cost of new entry
CREZ	Competitive Renewable Energy Zones
CRF	Capital recovery factor
CSAPR	Cross-State Air Pollution Rule
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
ESIG	Energy Systems Integration Group
EUE	Expected unserved energy
FERC	Federal Energy Regulatory Commission
HVDC	High-voltage direct current
ISO	Independent system operator
LCOE	Levelized cost of energy
LOLE	Loss of load expectation
LOLEv	Loss of load event
LOLH	Loss of load hours
LOLP	Loss of load probability
MISO	Midcontinent Independent System Operator
NOPR	Notice of Proposed Rulemaking
NOx	Nitrogen oxides
NYISO	New York Independent System Operator
RTO	Regional transmission organization
SOx	Sulfur oxides
SPP	Southwest Power Pool
VSC	Voltage source converter

Executive Summary

Achieving the country's rapid decarbonization and renewable energy goals requires not only significant investment in wind, solar, and other renewable generation technologies, but also investment in and expansion of the underlying transmission network. A robust transmission system can move low-cost renewable energy across long distances and improve reliability. The system benefits from the increased diversity in load and renewable generation: the grid spans regions having different weather patterns and experiencing periods of scarcity or abundance at different times. When one region faces a power shortage, a well-designed transmission grid provides support from neighboring areas.

A Need for Multi-Value Planning to Evaluate Transmission Investments

Currently, transmission planning processes are built around achieving a reliable system at the local level, not necessarily improving economic efficiency or bulk system reliability. Moreover, while the current planning framework may be efficient under average circumstances, it fails to protect consumers from tail-end risks—low-probability but high-impact events—and potential exposure to extreme costs.

Production costs, the de facto metric for measuring economic transmission benefits and justifying investment, are only one piece of the puzzle. A wide range of benefits should be considered when evaluating transmission, including reduced operating costs, environmental benefits, access to low-cost renewable energy, generation capital cost benefits, risk mitigation benefits, and improvements in reliability and resilience. In addition, transmission planning horizons should reflect the lifetime of the asset, going out far enough to see the benefits that arise with system changes. Moving away from a snapshot framework to assess multiple future scenarios is vital for effective planning. Not only does transmission provide near-term efficiency, it also serves as an insurance policy that protects customers against extreme weather or macroeconomic volatility.

Case Study of a Methodology to Quantify a Range of Benefits

The Energy Systems Integration Group's Transmission Task Force undertook a case study to demonstrate useful methodologies for employing a multi-value framework to plan transmission effectively. It quantifies two types of transmission upgrades: large-scale transmission upgrades connecting the West Texas renewable energy zones to East Texas and the Houston load center, and a transmission line between the Electric Reliability Council of Texas (ERCOT) and the southeastern United States (Georgia, Mississippi, and Alabama). This case study seeks to revitalize multi-value transmission planning, provide a playbook for transmission planners to implement on their own system, and inform comments and proposals to the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking (FERC NOPR)[i] and ongoing stakeholder efforts at independent system operators and regional transmission organizations on transmission planning reform.

i Federal Energy Regulatory Commission Notice of Proposed Rulemaking, April 2022, https://www.ferc.gov/news-events/news/ferc-issues-transmission-nopr-addressing-planning-cost-allocation.

Types of Transmission Benefits

Considerable work in recent years has helped to categorize and implement a wide range of transmission benefits. This study built on these and focused on six core benefits deemed most important for transmission planning reform (Table ES-1).[ii]

Study Results

Our results showed that a multi-value transmission planning framework yielded significant benefits beyond production cost savings. While production cost savings are enough for some of the evaluated transmission projects to break even, the multi-value framework showed that when a full range of benefits was evaluated, all three of the transmission projects studied had significantly higher benefit-cost ratios. Recognizing these benefits could ultimately change transmission investment decisions (Figures ES-1 and ES-2).

These results also highlight a key finding for transmission planning: different transmission projects can have large differences in the types of value they bring. Transmission that helps to access new, low-cost generating resources, and deliver that energy to load centers, yields large production cost savings and environmental savings, helps meet public policy goals, and brings risk mitigation benefits. Other transmission projects that help a region access more *diversified* resources are better suited to

TABLE ES-1

The Six Transmission Benefits Categories Evaluated

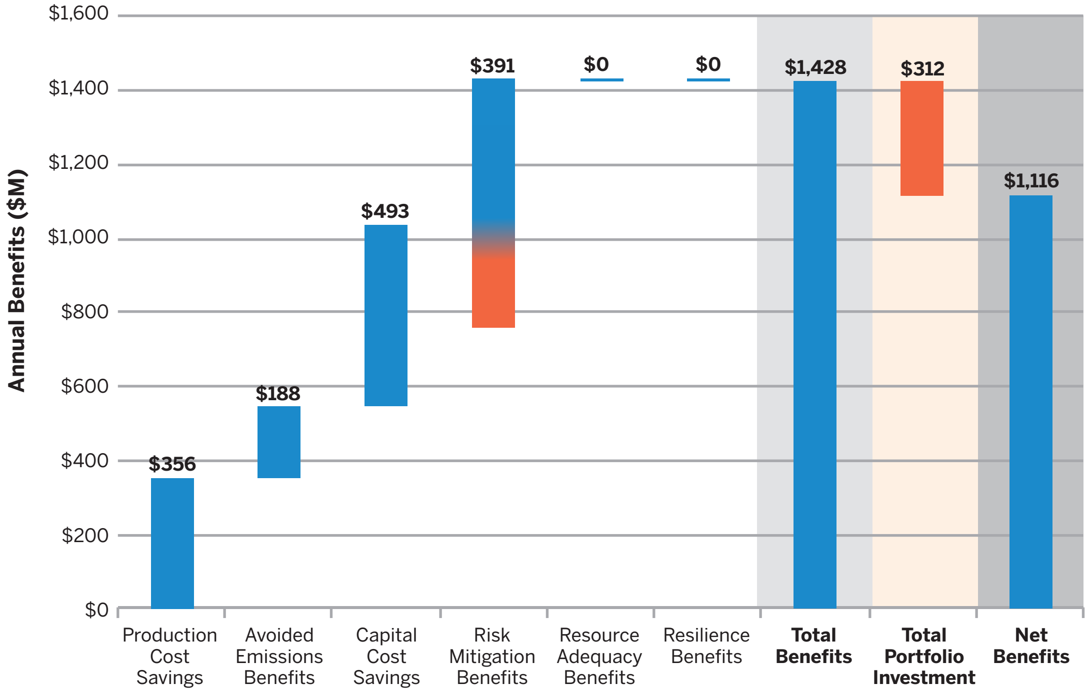
Benefit	Description
Production cost benefits	Quantification of fuel cost savings, reduced curtailment, variable operations and maintenance costs, reduced cycling of thermal power plants.
Emissions reduction benefits	The reduction in emissions of environmental pollutants, including CO_2, NOx, SOx.
Generation capital cost benefits	Reduced capital costs of new generating capacity and lower costs of achieving a renewable energy target from being able to access lower-cost renewable regions that are associated with better resource quality, lower land cost, and easier development.
Risk mitigation benefits	Production cost savings across a range of uncertain future conditions associated with varying gas prices, load growth, renewable build-out and thermal plant retirements.
Resource adequacy benefits	The reduction in loss-of-load expectation attributed to the transmission line, compared to the net cost of a new combustion turbine(s) necessary to achieve the same level of reliability.
Resilience benefits	The reduction in unserved energy attributed to the transmission line during the loss-of-load events remaining after resource adequacy improvements, valued at the ERCOT loss-of-load assumption of $20,000/MWh.

Source: Energy Systems Integration Group.

ii See, for example, J. Pfeifenberger, K. Spokas, J. M. Hagerty, J. Tsoukalis, R. Gramlich, M. Goggin, J. Caspary, and J. Schneider, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* (Boston, MA: The Brattle Group; Washington, DC: Grid Strategies, 2021), https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Planning-for-the-21st-Century-Proven-Practices-that-Increase-Value-and-Reduce-Costs.pdf.

FIGURE ES-1

Multi-Value Benefit Stacking for the Transmission Line Relieving the West Texas Export Constraint, 2030



The six bars on the left represent benefits that are added together to arrive at the total benefits of $1.4 billion. After investments are subtracted (red bar), the net annual benefits of the transmission line are calculated to be $1.1 billion (blue bar on the far right).

Source: Energy Systems Integration Group.

provide resource adequacy and resilience benefits. The latter have relatively greater generation capital cost benefits and provide an insurance policy against macroeconomic volatility, extreme weather, and other unexpected events.

The multi-value framework also examines the potential avoided cost for ratepayers during extreme events or macroeconomic uncertainty, showing that transmission is a valuable insurance policy for the system and one that will pay dividends throughout the energy transition.

Key Recommendations for Grid Planners

The planning processes in use today can be improved with the following recommendations for transmission planners, policymakers, and regulators.

1. **Go beyond production costs and implement a multi-value benefit framework.**

   Accurately assessing the wide range of benefits from transmission is important as the system transitions to zero-marginal-cost renewable resources. These benefits should be identified, prioritized, and clearly defined early in the transmission planning process.

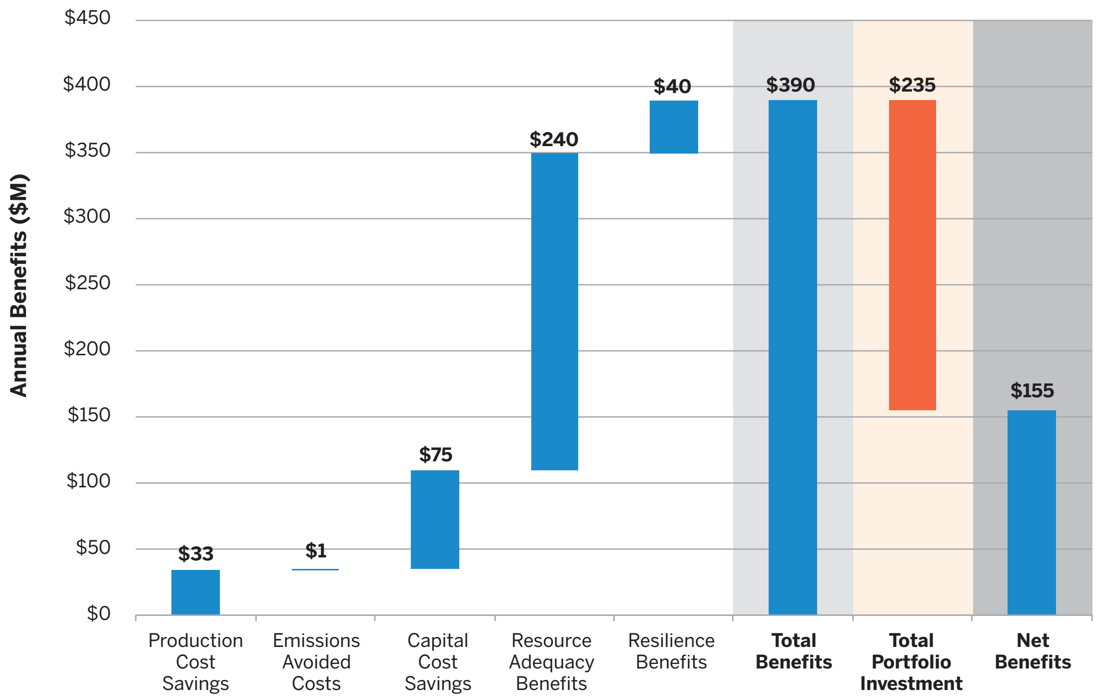
2. **Plan for the long term and start today.**

   Transmission infrastructure can be a 40- to 50-year asset. The planning horizon should reflect that and go out far enough to see the benefits that arise with specific system changes.

3. **Get comfortable with uncertainty and adopt established methods to deal with it.**

FIGURE ES-2

Multi-Value Benefit Stacking for the Transmission Line Connecting ERCOT and Southern Company, 2030



Results from stacking the multi-value benefits for the ERCOT-Southern Company transmission line show total benefits of $390 million, compared to $33 million when considering production cost savings only. This increases the benefit-cost ratio from 0.14 to 1.66.

Source: Energy Systems Integration Group.

Like all of us, grid planners do not have a crystal ball to see the future. The classic approach to solving this long-standing problem in power systems planning is to use heuristic-based scenario and parametric analysis. However, significant improvements in data science and statistics have been applied in other sectors, such as the tech and finance industries, and are now migrating to the energy field. Modern power planning tools offer significantly improved capabilities to better quantify risks and benefits.

4. Quantify resource adequacy and resilience benefits.

Transmission spanning regions that have different weather patterns can mitigate the impacts—both financial and social—of extreme events. This provides an insurance policy for ratepayers. Through transmission expansion, individual regions can achieve reliability with lower capacity investments than if they were unable to share energy with neighbors and had to build a full suite of resources themselves. When extreme weather strikes, *not* having built new interregional transmission can have devastating consequences for ratepayers.

5. Break down silos and plan interregional projects.

Interregional coordination is a bedrock of the energy transition. Reliability and resilience benefits accrue most strongly from transmission that connects electrically diverse systems, but market and planning constructs need to account for value from sharing between neighboring systems.

Enabling a proactive, scenario-based, multi-benefit framework for long-term regional transmission planning will ensure that the power system is reliable, efficient, and increasingly clean for today and into the future.

A New Framework for Transmission Planning

Achieving the country's rapid decarbonization and renewable energy goals requires not only significant investment in wind, solar, and other renewable generation technologies, but also investment in and expansion of the underlying transmission network. This network ensures that renewable generation can be delivered from remote wind and solar regions to load centers that consume clean energy. A foundational tenet of renewable integration is that transmission expansion is essential to meet decarbonization goals in a cost-effective manner while improving system reliability.

The transmission system is a key enabler of not only renewable energy, but of decarbonization and the energy transition more generally. A robust transmission system allows renewable generation in remote areas—ones with high-quality wind and solar resources and available land—to make its way to regions where it is needed most, in cities and load centers across the country. This network also allows the system to recognize load and renewable diversity benefits, as the grid spans regions having different weather patterns and thus experiencing periods of scarcity or abundance at different times. The grid also improves reliability and resilience. When one region is affected by extreme weather or unexpected outages, the transmission grid provides support from neighboring areas.

The Value of Transmission Investments

Transmission is an established solution for improving system efficiency, reliability, and resilience. However, the significant costs, the impact to underlying market forces, and public opposition to new transmission development place considerable burdens on the transmission planning process to justify new transmission builds. The clean energy transition requires significant transmission expansion to better interconnect new generation resources with the existing network. At the same time, the importance of electricity to our daily lives is increasing due to electrification and higher expectations on service. This, in turn, drives a need for increased interregional transmission between neighboring regions to ensure adequate interchange capability.

The traditional approach to capturing the benefits of new transmission is based largely on the change in total system fuel costs that result from more efficient utilization of system resources. Yet, this approach is less appropriate as the electricity system's costs depend less on variable fuel costs and more on long-term investment costs of renewable energy.

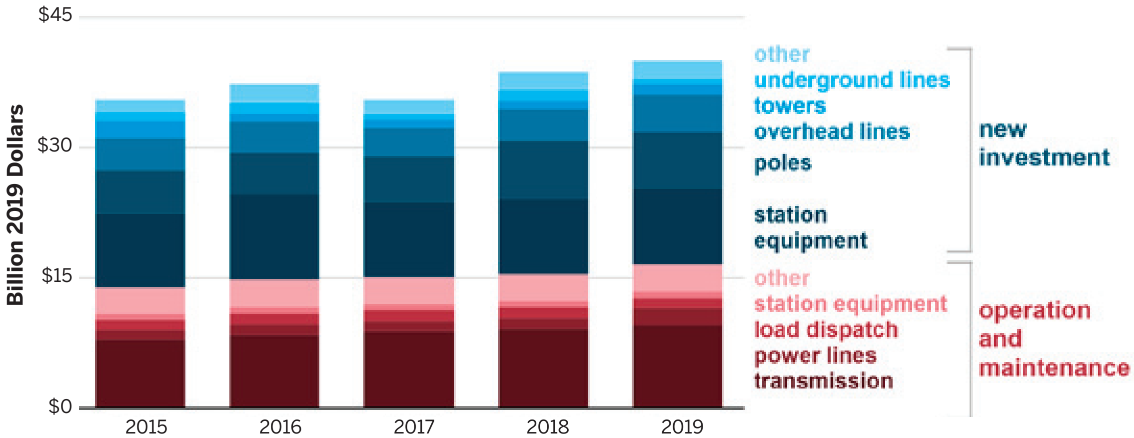
However, if transmission is a key enabler of the energy transition, the low-hanging fruit has already been picked. Interconnection queues across the country are jammed, and developers of new projects often wait years to interconnect new plants and face costly upgrades when they do. While transmission investment has increased notably since 2000, from $9.1 billion in 2000 to $40 billion in 2019, new investment has remained flat for the past several years, despite the rapid growth in new renewables and thermal plant retirements (Figure 1) (EIA, 2021b).

A Need for More Holistic Economic Planning

More than 90 percent of these transmission upgrades have been based solely on local reliability needs, with the majority of this investment going toward operations and maintenance of existing infrastructure, replacement of aging infrastructure, and new substations for plant interconnection (Pfeifenberger et al., 2021). There has been only limited investment in new economic

FIGURE 1

Annual Spending on the Electric Transmission System by Major U.S. Utilities, 2015–2019



Source: U.S. Energy Information Administration.

transmission lines and corridors for a robust and efficient power grid for the energy transition.[1]

In contrast to local reliability improvements, economic transmission projects focus on lowering the cost of delivered energy to ratepayers. They do so by reducing congestion—enabling low-cost generation from one region to serve high-price load centers in urban areas where generation is more expensive or non-existent. Economic transmission projects can contribute to bulk system reliability and resource adequacy through interregional sharing of resources, accessing geographic diversity of renewables and system load. When transmission spans regions that have different weather patterns, extreme events can be mitigated, providing an insurance policy for ratepayers. In doing so, individual regions can achieve reliability with less capacity investments and cost than if they were unable to share energy with neighbors and had to build a full suite of resources themselves.

All too often, however, transmission planning overlooks the economic projects altogether, or it narrowly focuses only on reductions in fuel costs and other operating costs (production costs) that are easy to calculate. Therefore, to arrive at a more accurate and realistic benefit-cost ratio assigned to economic transmission planning projects, one that reflects their true value, a multi-value benefits framework is needed.

Current Roadblocks for Transmission

Despite the need, new economic transmission has not been built at a significant level for many decades. The question is, why? What roadblocks, barriers, and limitations in our transmission planning are causing slow development of a key enabler of the power system's ability to decarbonize? The Energy Systems Integration Group's (ESIG) Transmission Task Force sought to answer these questions and conducted a set of interviews with industry experts to discuss the challenges that independent system operators and regional transmission organizations (ISOs/RTOs), state policymakers, and developers face in their efforts to build new transmission.

Throughout these discussions four main challenges were consistently seen across the country:

1 We expect to see transmission spend to increase in the near future as decarbonization goals are incorporated into the planning processes. For instance, the Midcontinent Independent System Operator is expected to approve approximately $30 billion in new transmission that is needed to reliably deliver energy in a cleaner energy future.

1. **Transmission planning processes are built around achieving a reliable system at the local level, not necessarily for additional value of economic efficiency or bulk system reliability.**

Over the last few decades, our transmission planning processes have been geared narrowly toward reliability needs and upgrades to existing equipment. Across the country, very few projects have been built for economic efficiency or congestion relief. This stems in part from the fact that many areas have not performed robust economic planning in the last several years and that local reliability upgrades are required to serve load. A typical reliability upgrade is smaller in size, relieves a reliability violation that must be fixed, often does not cross different jurisdictions, and can allocate its cost across the load that benefits from the upgrade.

Economic planning is almost the opposite. Economic projects are not required to serve load, tend to have larger physical footprints that often cross multiple jurisdictions, and seek to allocate costs based on a calculated expected benefit, which different load-serving entities may dispute. One advantage of interconnection processes that study generators in clusters is the ability to allocate the costs of these transmission upgrades across multiple projects. However, even if benefits are calculated correctly and show significant cost savings across the system, ensuring that the consumers who benefit the most, pay the most, and overcoming political and community opposition can be daunting.

But large economic projects, those spanning large geographies (including multiple system operators), targeting transmission congestion, and accessing renewable energy zones are precisely the ones needed for the energy transition. However, to determine the full value that these large-scale transmission projects can provide requires analyzing, identifying, and quantifying a broad range of benefits.

2. **The generator interconnection queue process favors short-term upgrades that are just enough for the current projects, rather than enabling future projects.**

The current interconnection and transmission service approach is oriented toward building the transmission needed to provide the specific service requested by a generator or set of generators in the short term. This process does not consider potential future projects that could be enabled by investments made today. This issue is compounded in many markets by a flawed cost allocation mechanism that disincentivizes generator interconnection in regions where it is likely to incur network upgrade costs.

The current interconnection and transmission service approach creates a patchwork of small transmission upgrades that maintain the status quo, such as low-voltage radial tie-lines and small substation upgrades, and may not necessarily improve overall transmission capability to move power across the system. This approach creates a number of issues. First, there is the possibility that smaller generation projects are unable to bear the cost of transmission upgrades needed to interconnect; these transmission costs make the generation projects uneconomic, and they drop out of the cluster study. In addition, today's interconnection processes can incorporate projects that are speculative. These unready projects make it seem that more transmission upgrades are needed and thus make the transmission upgrades for ready projects appear higher than they actually are. Lastly, when the generation projects ultimately withdraw from the interconnection process—whether because of untenable upgrade costs or because they were speculative—that withdrawal requires all the other generators requesting interconnection to be restudied. This significantly increases the timeline to bring on new projects.

Transmission planning needs to be more proactive by incorporating long-term transmission needs to achieve policy goals. This proactive approach would identify regions where generation projects are expected to locate by balancing policy, capacity factors, fuel availability, land availability, load preferences, and transmission costs. In the classic "if you build it, they will come" mentality, transmission should be designed to accommodate expected load and generation growth. This process was effectively implemented in the Electric Reliability Council of Texas (ERCOT) system through the 2007 Competitive Renewable Energy Zones (CREZ) (ERCOT, 2008), the Midcontinent Independent System Operator's (MISO) Multi-Value Projects (MISO, 2017), and the Australian Energy Market Operator's recognition and prioritization of renewable energy zones (AEMO, 2018). The success of ERCOT's proactive transmission planning approach has been extended by an efficient interconnection process that allows resources to interconnect quickly and the development of prudent network upgrade costs to ensure deliverability.

3. There is minimal interregional transmission planning between ISO/RTOs and utilities.

The United States is made up of a patchwork of many different transmission operators, utilities, ISOs/RTOs, states, and regional entities. There is little to no inter-regional transmission planning between ISOs/RTOs, and when transmission is successfully built, it is almost always within the boundaries of a single ISO/RTO. As one system planner interviewed for this project stated, "we know how to design and plan for our system, but there are benefits sitting right next door that do not get looked at seriously because that is in another RTO."

A narrow focus on an individual footprint leaves benefits on the table, but it also exposes consumers to risk. Take Winter Storm Uri as an example. ERCOT experienced multiple days of consecutive load shedding—at times up to 30 percent of the system load—while neighboring regions in the Southwest and Southeast had mild weather and normal operating conditions (Goggin, 2021). Unfortunately, as an isolated interconnection, ERCOT was unable to access these resources due to lack of transmission. MISO and the Southwest Power Pool (SPP) faced similar weather conditions but relatively modest disruptions, at least in part because of their interconnectedness with the Eastern Interconnection.

4. Allocating costs is difficult and controversial.

One of the most controversial challenges posed by new transmission is who pays for it. Even if the transmission planning is conducted using high-quality, state-of-the-art methods and tools, the allocation of costs across a patchwork of jurisdictions—and ultimately ratepayers—is difficult. Ideally, costs are allocated according to how much someone benefits. However, while the upfront costs of new transmission are known, the long-term benefits depend on future conditions of load, fuel prices, and renewable levels—all of which will vary over time. Benefits are also in the eye of the benefitting party, and not all states or load-serving entities have the same goals or future expectations.

This creates a formidable barrier to many transmission projects. In addition, even if a jurisdiction or state is affected neutrally by a project (incurring neither benefits nor costs), it may not want to have a transmission facility traverse its state so that another state can benefit. This situation can be very difficult to overcome in multi-state ISOs/RTOs, and nearly impossible when attempting to cross ISO/RTO boundaries. Benefit allocation can stymie a project even if it is broadly recognized to have large net savings for the system (or society) as a whole. Because transmission may cross multiple jurisdictions and may create both winners and losers, proactive federal or state policy and regulation may be required.

While each of these four barriers must be overcome for prudent transmission planning, this study focuses on the first: demonstrating a need for improvements in economic transmission planning. This is the foundational element of transmission planning—if we cannot properly quantify benefits of new transmission, interregional planning and cost allocation are moot points.

A Need for Multi-Value Planning

To enable the clean energy transition in a cost-effective and reliable manner, we need to think more broadly about transmission planning. Production costs—the de facto metric for measuring economic transmission benefits and justifying investment—are only one piece of the puzzle, and a wide range of benefits should be considered when evaluating transmission. It is important to adopt a multi-value framework, which encapsulates benefits from reduced operating costs, environmental benefits, access to low-cost renewable energy, and improvements in reliability and resilience. Adopting a multi-value framework becomes increasingly vital as the system transitions to zero-marginal-cost renewable resources, and grid services that were historically provided by thermal generation need to be replaced and provided through other means.

To ensure that we reap the full benefits of large-scale transmission, planning processes need to look further out, both *temporally* and *spatially*. Transmission infrastructure has a long useful life, exceeding the 20 years typically used in transmission planning, and can often reach 40 or 50 years. The planning horizon should go out far enough to see the benefits that arise with system changes.

Multi-value planning is not just about expanding the benefits that are evaluated. It is also about identifying and properly accounting for risk to and potential costs for ratepayers. While the current planning framework may be efficient under average circumstances, it fails to protect consumers from tail-end risks—low-probability but high-impact events—and potential exposure to high-cost events. Geopolitical risks, macroeconomic changes, inflation, and climate change have disturbed the status quo, resulting in increasing gas price volatility, accelerated load growth from the electrification of the building and transportation sectors, and more severe weather events. These changes are altering the relative economics of different generation sources, increasing the benefits associated with the renewable transition and driving additional capacity needs.

If we have learned anything during the COVID-19 pandemic, it is that we cannot effectively predict the next few years, let alone decades into the future. Single-point forecasts are too narrow and should be broadened through scenario planning and probabilistic (or stochastic) analysis. While knowing what, when, and where high-impact, low-probability events will occur is impossible, transmission can be a low-regrets insurance policy that enables a wide range of future outcomes like advancing clean energy and reducing the likelihood of blackouts and the costs of extreme events. Planning processes to address resilience, resource adequacy, and public policy goals, in particular, should not focus solely on increasing benefits to the grid and consumers under normal conditions; they should also focus on reducing risks of low-probability but high-impact events. Transmission serves as an insurance policy against macroeconomic volatility, extreme weather, and other unexpected events. Moving away from an individual snapshot analytical framework to assessing multiple future scenarios is vital for effective planning.

Unfortunately, transmission planning across the country has not always employed novel evaluation and modeling techniques to address these roadblocks. Despite the availability of methods for assessing the multiple benefits of transmission projects, only a few regions have employed modern transmission planning practices. These practices include proactively planning for new generation to solve bottlenecks in transmission planning, scenario-based planning that identifies a range of future conditions, portfolio-based upgrades evaluating multiple transmission investments simultaneously, and interregional planning between jurisdictions.

Establishing Methodologies for a Multi-Value Framework

The multi-value framework is a foundational requirement of transmission planning analysis. We must make sure we can properly evaluate transmission benefits before we can effectively address cost allocation or interregional coordination. This study is intended to serve as a blueprint for transmission planning by developing a methodology to identify and prioritize transmission's benefits and by demonstrating the analytical steps necessary to quantify such benefits. The benefits included in this report, while not exhaustive, include production costs, emissions and environmental benefits, generation capital cost savings, risk mitigation, resource adequacy, and resilience.

Study Overview and Objectives

The objective of this study, therefore, is to provide a case study and methodologies to accurately quantify a range of transmission benefits. The case study was developed and reviewed by a broad group of technical experts to add to the conversation at the Federal Energy Regulatory Commission (FERC) and other decisionmaking bodies on how to employ a multi-value framework to most effectively plan transmission moving forward, in a way that better incorporates the variety of benefits these projects produce. Specifically, this case study seeks to:

- Revitalize multi-value transmission planning
- Provide a playbook for transmission planners
- Inform comments and proposals to the FERC Notice of Proposed Rulemaking (NOPR) (FERC, 2022) and ongoing stakeholder efforts at ISOs/RTOs on transmission planning

This case study evaluated two large-scale transmission upgrades to the West Texas Export constraint in ERCOT and a large-scale transmission project connecting ERCOT to Southern Company's territory in the Southeast using a multi-value approach.

Results of Applying a Multi-Value Transmission Planning Framework

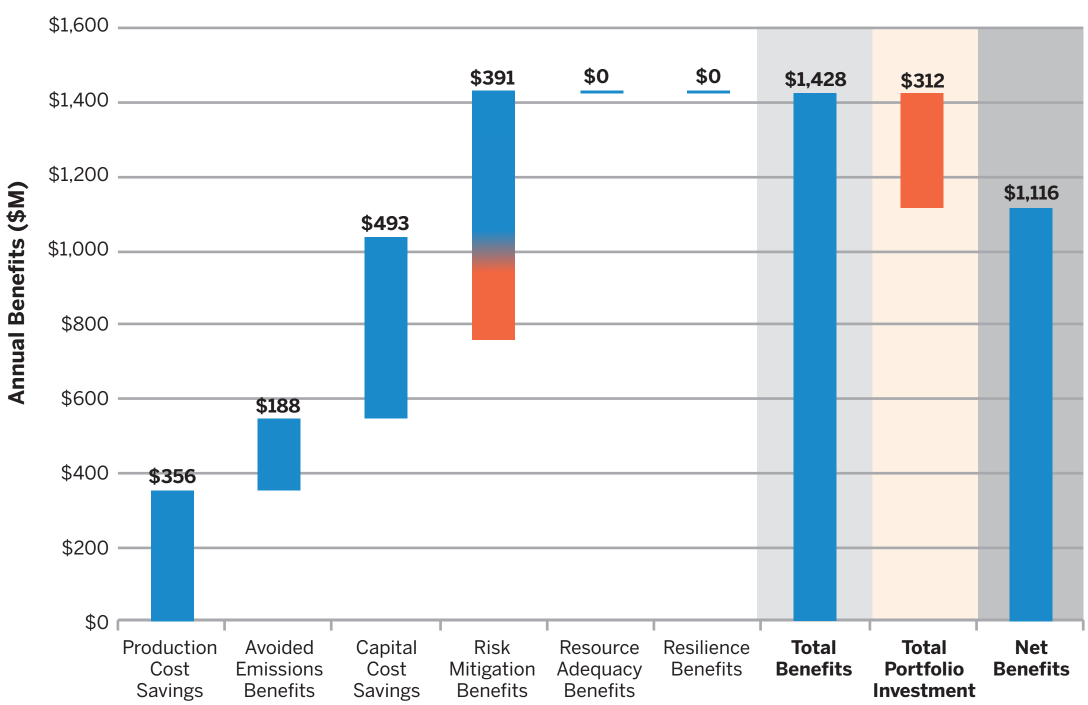
The results of our analysis using a multi-value transmission planning framework showed significant benefits from large-scale transmission projects, beyond production cost savings. While some of the evaluated transmission projects do not break even based on production cost savings alone, the multi-value framework examining a range of benefits shows that all of the transmission projects evaluated have benefits for the system that outweigh the transmission investment (Figure 2 and Figure 3).

These multi-value benefit stacks quantify and sum the benefits of the six categories evaluated in the study, where the height of the segments reflects the relative value of each benefit provided by the transmission line. The total benefits can be compared against the necessary capital investment cost (orange bar) to calculate the net benefits (blue bar on the far right). This benefit-cost framework allows transmission planners to make key decisions on whether to invest in new transmission projects and to compare different projects against one another. To justify new transmission, benefit-cost ratios (total benefit divided by total cost) must typically be 1.3 to 1.5 or higher (Hogan, 2018; Fink et al., 2011).

These results also highlight a key finding for transmission planning: different transmission projects can show large differences in the types of value they bring. Broadly speaking, there is transmission that can help access new, low-cost generating resources, delivering energy to load centers, while other transmission is better suited to provide resource adequacy and resilience benefits. The former will yield large production cost savings and environmental savings, help meet public policy goals, and have risk mitigation benefits, while the latter will have a disproportionate benefit for avoided expenses for new capacity and avoided costs from extreme events.

FIGURE 2

Multi-Value Benefit Stacking for Transmission Projects Relieving the West Texas Export Constraint, 2030



The six bars on the left represent benefits that are added together to arrive at the total benefits of $1.4 billion. After investments are subtracted (red bar), the net annual benefits of the transmission line are calculated to be $1.1 billion (blue bar on the far right).

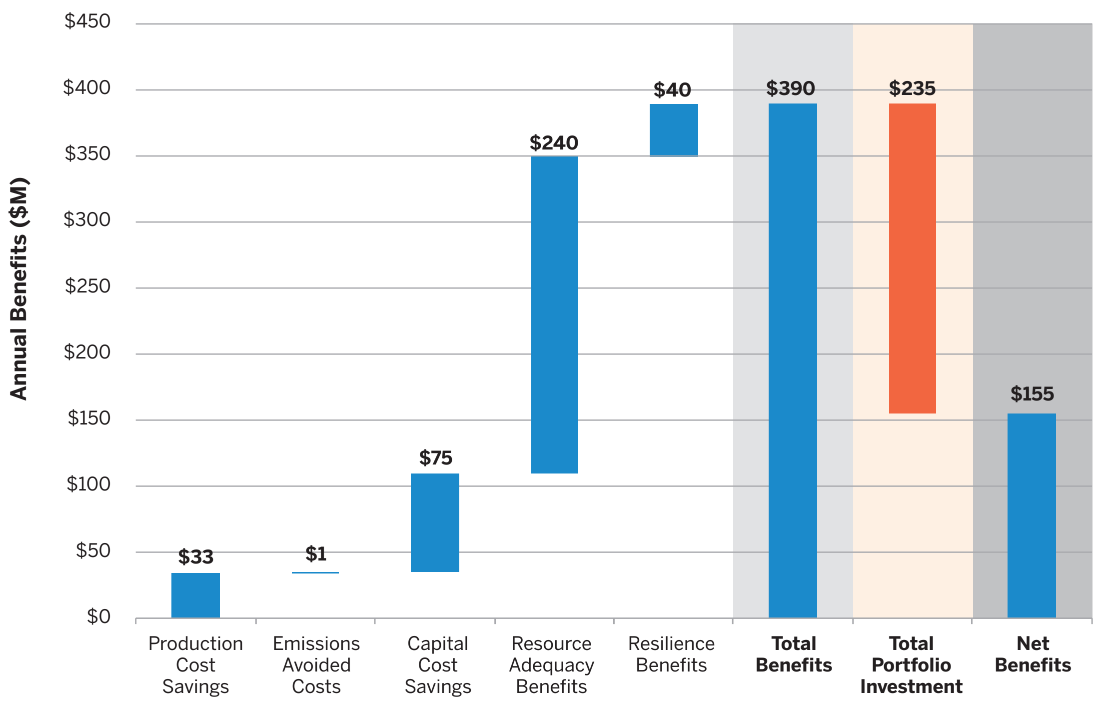
Source: Energy Systems Integration Group.

Finally, the results of this study indicate that the multi-value framework not only sums several major benefits for transmission projects, but also highlights the risk mitigation that transmission provides to ratepayers. Understanding the potential avoided cost for ratepayers during extreme events or macroeconomic uncertainty shows that transmission is a valuable insurance policy for the system and one that pays dividends throughout the energy transition.

The remainder of this report goes into more depth on the multi-benefit framework itself and then applies it to the first part of the study evaluating ERCOT, quantifying the benefits brought by two versions of proposed West Texas Export transmission upgrades. It then looks at interregional transmission planning and evaluates the same set of benefits for a transmission line between ERCOT and the Southern Company to the east. The report concludes with targeted recommendations for policymakers, regulators, and transmission planners in both Texas and nationally.

FIGURE 3

Multi-Value Benefit Stacking for the Transmission Line Connecting ERCOT and Southern Company, 2030



Results from stacking the multi-value benefits for the ERCOT-Southern Company transmission line show total benefits of $390 million, compared to $33 million when considering production cost savings only. This increases the benefit-cost ratio from 0.14 to 1.66.

Source: Energy Systems Integration Group.

A Multi-Benefits Approach to Long-Term Planning

Ensuring that our transmission planning processes capture a wide range of economic benefits is critical to evaluating, justifying, and building new transmission infrastructure. To date, transmission planning across the country overwhelmingly takes an incremental, local upgrade approach that does not account for the wide range of benefits from transmission upgrades planned at a regional or interregional scale. While not an exhaustive list, these broader benefits may include production costs, emissions and environmental benefits, generation capital cost savings, risk mitigation, resource adequacy benefits, and resilience benefits. Moreover, transmission can mitigate costs imposed by severe weather and other catastrophic events. On average, transmission may bring modest savings most years, but brings large savings during rare, high-impact events.

Moving Beyond Production Cost Savings to Assess a Wider Range of Benefits

Where broader economic transmission planning is conducted, many ISOs/RTOs rely wholly on adjusted production cost savings to determine whether a proposed transmission line is approved. Adjusted production costs include the variable costs of producing electricity—namely fuel, variable operations and maintenance, start-up and shutdown, and emissions costs, which are then adjusted for any increase in costs for imports of electricity or revenues associated with exports.

Using adjusted production cost as the primary, or sole, metric for evaluating transmission benefits is problematic for two reasons. First, it leaves significant value on the table by largely ignoring some of the most important reasons why transmission is needed. For example, it almost completely excludes benefits from system reliability, resource adequacy, and capacity. It also excludes the benefits of accessing lower-cost renewables—which is largely a capital cost savings rather than production cost savings. In regions that do not have carbon markets or other emissions prices, the benefits of avoided emissions also do not get considered under a production cost approach, and public policy goals are omitted altogether.

Second, as the grid transitions to increasing shares of renewable energy, baseline production costs inherently shrink. Renewable energy is a zero-marginal-cost resource, as it does not have fuel costs or variable operations and maintenance costs. So, as its share on the system increases, the system-wide production costs decrease. As a result, the benefits of any system improvement—transmission included—appear diminished in a high-renewable future.

In the absence of new transmission, ratepayers are exposed to significant risks. These risks can be from macroeconomic drivers like changes in load growth or fuel prices. They can be imposed by not having enough transmission linkages during reliability events, leaving one region with not enough capacity to serve load while a neighbor has surplus. Having a transmission system that spans regional weather patterns can mitigate extreme weather events and the impacts of climate change.

Since the potential for production cost savings is decreasing with increased zero-marginal-cost resources like wind, solar, and storage—savings that even historically have reflected only a fraction of the benefits of transmission—additional metrics should be used to accurately quantify the benefits of large-scale transmission. Continued reliance on production costs as the primary metric for evaluating transmission will delay fulfilment of public policy goals and disproportionately favor the development of new resources that have substantial fuel costs, emissions, and incorrectly reflected reliability benefits.

Types of Transmission Benefits

There has been considerable work in recent years to help categorize, illustrate, and even begin to implement a wide range of transmission benefits in planning processes (Hogan, 2018; Fink et al., 2021; McCalley et al., 2012; Van Horn, Pfeifenberger, and Ruiz, 2020; ESIG, 2021).

Notably, Pfeifenberger et al. (2021) developed a set of transmission planning guidelines that recognize the full value of new transmission deployment. This work identified eight categories of benefits that included 21 distinct transmission benefits in addition to the traditional adjusted production cost benefits commonly used in transmission planning. While some of these are simply

TABLE 1
Electricity System Benefits of Transmission Investments

Benefit Category	Transmission Benefit
1. Traditional production cost savings	Adjusted production cost savings as currently estimated in most planning processes
2. Additional production cost savings	i. Impact of generation outages on ancillary service 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 amounts and costs of operating reserves and other ancillary services
	viii. Mitigation of amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run 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 wildfire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operation benefits

Source: Adapted from Pfeifenberger et al. (2021)/The Brattle Group.

more detailed and specific production cost benefits (i.e., better incorporation of losses, forecast error, plant cycling, etc.), there are six categories and more than 10 benefits that are independent of production cost. See Table 1 (p. 9).

In addition to these benefits for the electricity system, there are other benefits, including employment and economic stimulus benefits for the economy at large and health benefits associated with the reduced emissions.

For practical purposes, these benefits need to be prioritized and a smaller subset put into practice. Transmission planning is already a complicated and labor-intensive process across ISOs/RTOs, and any additional work and analytical burden should be kept as minimal as possible. What is important is the identification and listing of the benefits early in the transmission planning process so that planners can critically evaluate which benefits are most important or likely most pronounced for the project under consideration. Different projects will yield different levels of benefits across the range listed in Table 1, and the methodology we demonstrate here can be used to quantify the key benefits for both large-scale intraregional transmission as well as interregional transmission.

Recent Examples of Multi-Value Transmission Benefits

While a multi-value project approach is not used consistently across transmission projects, and standardized methodologies have not yet been established, this approach has been used with success in recent years by MISO (MISO, 2012; 2022a), the New York Independent System Operator (NYISO) (NYISO, 2017; 2019), and SPP (SPP, 2016). Most recently, the MISO long-range transmission planning process has sought to establish a "transmission roadmap" for a long-term horizon that will be the foundation to drive future investment decisions and enable reliable and economic delivery of energy in the future with lower-carbon resources (MISO, 2022b). However, even in regions that use a multi-value framework for some transmission projects, it is only in a limited fashion for individual studies. A multi-value framework is needed across all the ISO/RTO planning processes.

The increased benefits of a multi-value approach can be seen in the MISO Long Range Transmission Planning Tranche 1 proposed portfolio, which included a collection of 345 kV transmission projects across the MISO

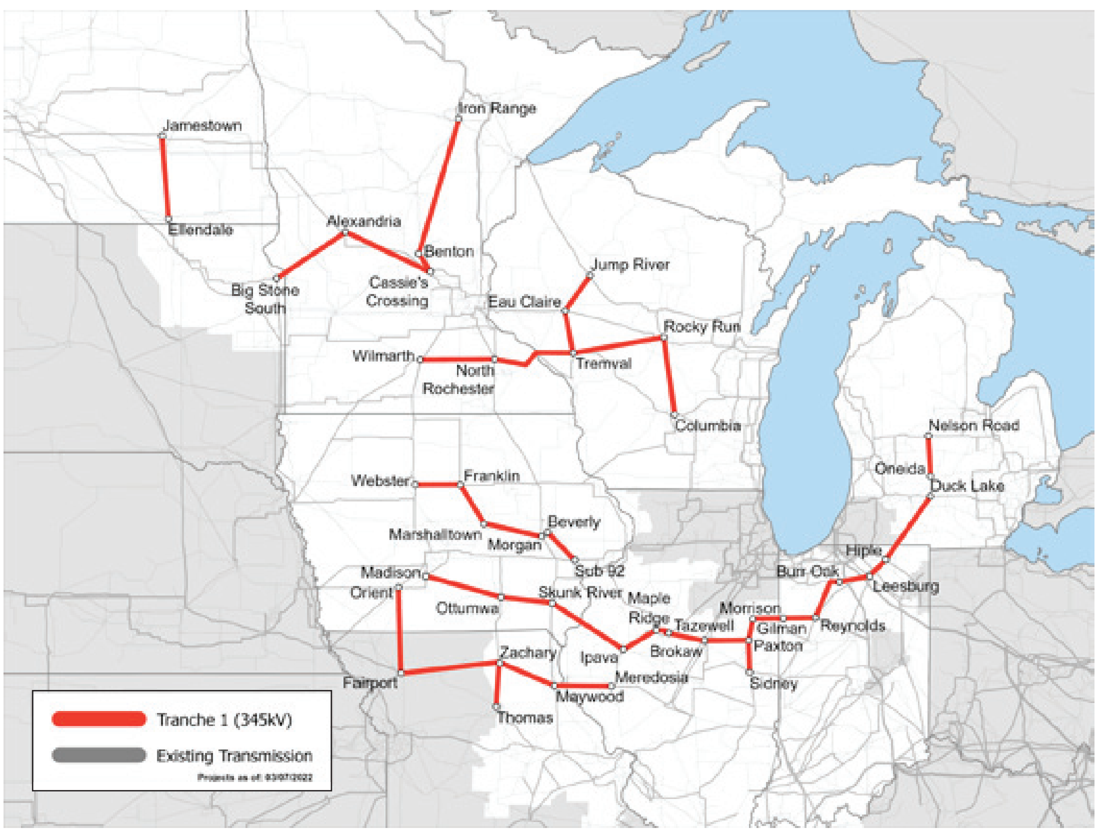
Midwest subregion totaling $10.4 billion in transmission upgrade costs (Figure 4). This translates to a present value revenue requirement of $14.1 to 16.9 billion when evaluated across a 20- or 40-year project life and a 6.9 percent discount rate.

The projects were approximately break-even when evaluated across only production cost savings and did not have an acceptable benefit-cost ratio to justify them using production cost savings benefits alone. When the projects were evaluated, the present value of production cost benefits was $16.4 billion, or a 1.05 benefit-cost ratio. However, the production cost benefits accounted for only a minority of the total project benefits (31 percent). When a more complete set of benefits was quantified (see Figure 5, p. 12), the total value of the project was $53.3 billion, with a benefit-cost ratio of 3.4, clearly making the portfolio of projects economic and justifiable (MISO, 2022b).

From this example, several important observations can be made. First, production cost savings alone did not justify the portfolio of projects, but when the portfolio was evaluated across a wider, more realistic range of benefits, the economics became significantly more favorable. Second, the process shows that any collection of three benefits alone would justify the projects. As will be seen below, different types of projects yield different sets of benefits. And finally, the project horizon is an important assumption for transmission valuation. Shifting the project life from 20 to 40 years, which is important for assets with a lifetime of 50 years or more, doubled the benefit-cost ratio. This highlights the importance of using a long horizon to evaluate long-term infrastructure and social projects like transmission. Too often transmission projects, which have a useful life of longer than 20 years and have many components that can reach 50 years, are evaluated under short-term planning assumptions that only consider benefits across 10 to 20 years.

FIGURE 4

Map of Proposed MISO Long Range Transmission Planning Tranche 1 Transmission Upgrades

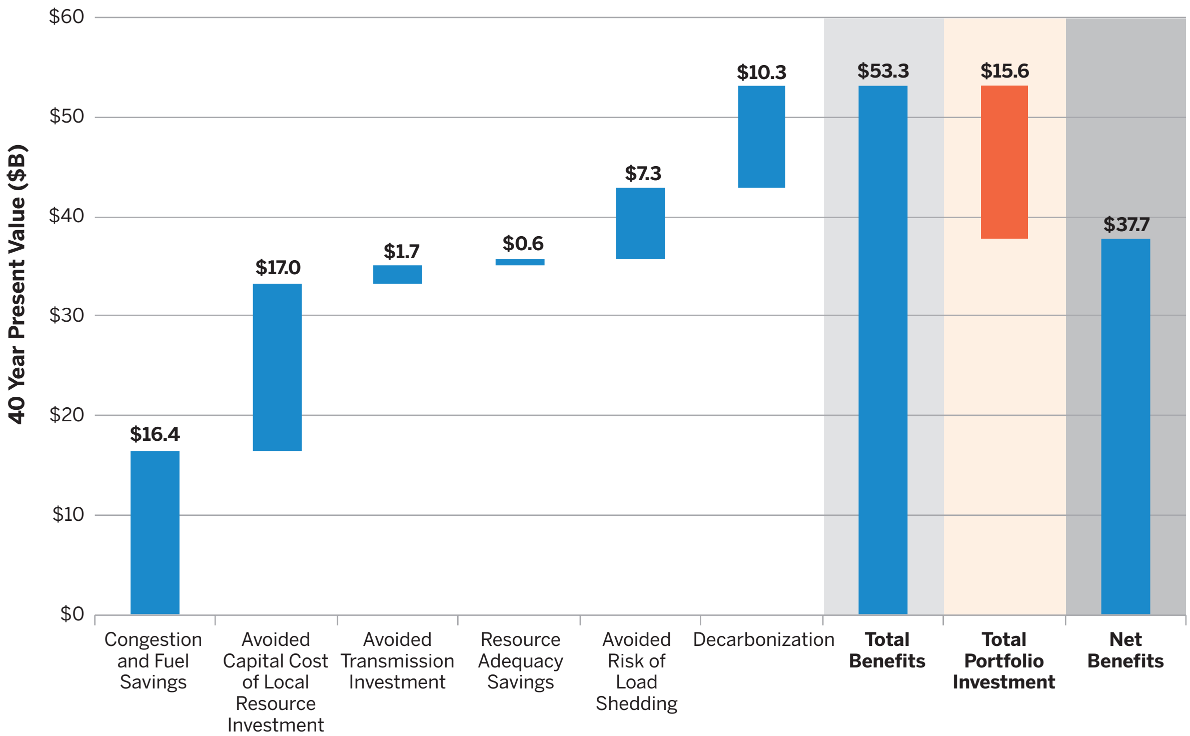


Source: Midcontinent Independent System Operator.

However, despite the success of the MISO process and similar initiatives at SPP, NYISO, the California Independent System Operator (CAISO), and others, these approaches are not yet standard industry practice. And even when an ISO or RTO employs the multi-value framework in some studies, it is not consistently applied across other transmission planning studies. For example, a multi-value framework is not used to evaluate network upgrade costs that are identified as part of the interconnection process. While significant effort has already been devoted to reviewing recent transmission planning processes and identifying successful implementation of a multi-value framework, interregional planning between ISO and RTO footprints, and even between states within a single RTO, is severely limited.

FIGURE 5

Example Benefits Stack from MISO Long Range Transmission Planning Tranche 1 Projects



Transmission benefits associated with MISO's proposed long-range transmission investments across a range six benefit types. Results show that the median full benefit stack outweighs the investment by $37.7 billion.

Source: Adapted from Midcontinent Independent System Operator (2022a).

A Case Study from ERCOT

This study analyzed two potential transmission projects: a transmission upgrade between the western and eastern regions of Texas, and an interregional transmission line between ERCOT and Southern Company in the Southeast. The first project studied is an upgrade to the West Texas Export interface, including a combination of 345 kV AC transmission lines and the potential for a high-voltage DC (HVDC) line to Houston, which were some of solutions proposed by ERCOT to address the West Texas Export congestion. This example provides a detailed analysis of the multi-value benefits of transmission to access a region with abundant low-cost renewables. The second project studied was a proposed interregional HVDC transmission project linking Southern Company in the southeastern United States to ERCOT, which is based on a similar project currently proposed by developers. This example provides a valuable study to evaluate the benefits of interregional planning, a key component to the FERC NOPR and a component typically not evaluated in ERCOT's regional planning processes.[2]

Why Texas?

ERCOT was selected as a case study to evaluate the importance of a multi-value transmission framework. As a separate interconnection, with limited transfer capability to neighboring systems, ERCOT provides a valuable case study for the benefits of large-scale transmission, between the renewable energy zone of West Texas and both East Texas and the Houston load center, and between West Texas and Southern Company in the U.S. Southeast (Mississippi, Alabama, and Georgia). First and foremost, we want to be clear that this case study is intended to describe and demonstrate the methodology for assessing the benefit-cost ratio of projects based on multiple benefits criteria; it is not a justification of a specific transmission project. The goal of the study was to implement the methods of a multi-value framework using real-world examples and to provide recommendations both in ERCOT and in ISOs/RTOs and utilities across the country. While examples are specific to Texas, the overall methodology is broadly applicable to future efforts in and between all ISOs/RTOs to invest in and expand transmission infrastructure.

ERCOT was selected for the case study for four reasons:

- Until recently, economic transmission planning in ERCOT required that only production cost savings could be used to justify, and cost allocate, proposed transmission projects. Thus, the multi-value framework was precluded from use by Texas statute. Following the February 2021 winter storm, Texas Senate Bill 1281 made changes to the economic planning criteria used by ERCOT, reintroducing the consumer benefit test that allows for a broader interpretation of transmission benefits in economic planning. The details of this new legislation are yet to be determined, which presents the opportunity for new methodologies, such as multi-value planning, to inform the legislature on how much economic value is being missed and how the risks of outages are being exacerbated through the use of narrow transmission planning criteria (Bernecker, 2022).

2 While ERCOT is not under FERC jurisdiction, the methods developed in this case study are intended to be applied more broadly and thus applicable to the FERC NOPR on Regional Transmission Planning (Docket No. RM21-17).

- West Texas has some of the best wind and solar resources in the world and is attractive to plant developers due to its low population density and developable land. However, continued development of these resources may stall due to transmission constraints.
- The West Texas Export interface is ERCOT's most expensive transmission constraint, projected to reach a congestion rent of $385 and $412 million per year in 2023 and 2026, respectively (ERCOT, 2021b). The increased congestion rent due to the transmission constraint means that lower-cost electricity is unable to flow from west to east. This requires more expensive generators that are closer to the load to turn on, translating directly to higher costs for ratepayers.
- ERCOT is its own interconnection with limited transfer capability between neighboring regions that have distinct resource mixes and load profiles. It thus provides a unique case study where the benefits of the addition of transmission lines crossing state and jurisdictional borders can be compared against the costs, reliability, and resilience of a relatively isolated system.

ERCOT recently released the *Long-Term West Texas Export Study Report*, a detailed and comprehensive transmission planning study that evaluated production cost savings for proposed upgrades in West Texas (ERCOT, 2022). The study evaluated only production cost benefits; therefore, it provides a good starting point for the multi-value framework, allowing the results of our methodology to be directly aligned with ISO/RTO transmission planning efforts.

Two proposed transmission upgrades evaluated in the *Long-Term West Texas Export Study Report* were included in this analysis. The first includes proposed upgrades to the West Texas Export interface, including a combination of 345 kV AC transmission lines and the potential for a high-voltage DC (HVDC) line to Houston. This example provides a detailed analysis of the multiple benefits of transmission to access a region with abundant low-cost renewables. The second transmission upgrade studied was a proposed interregional HVDC transmission project linking Southern Company in the southeastern United States to ERCOT. This example provides a valuable study to evaluate the benefits of interregional planning, a key component to the FERC NOPR, and typically not evaluated in ERCOT's regional planning processes.

West Texas Export Constraint

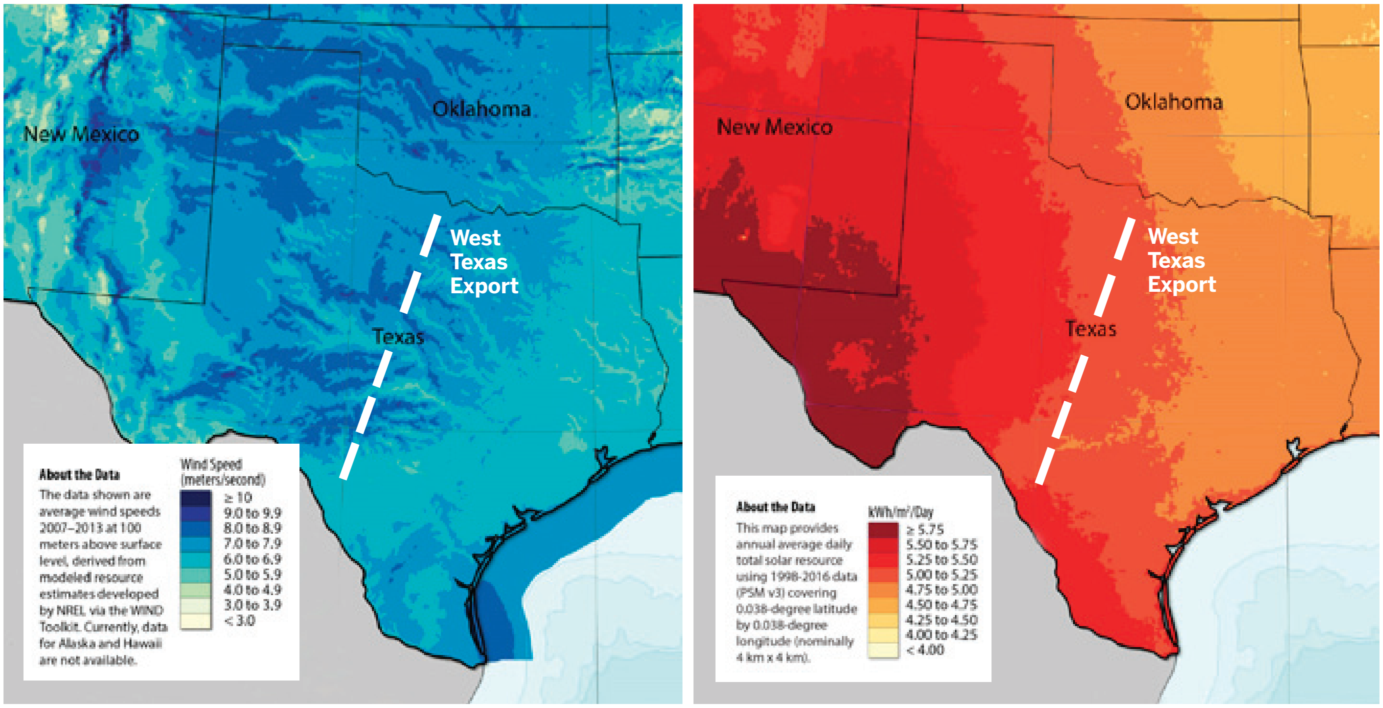
West Texas is one of the largest and most successful renewable energy zones in the world. This success is in large part due to the proactive nature of the CREZ transmission projects that were developed in the late 2000s. According to ERCOT, "significant amounts of inverter-based resources (IBR), primarily wind and solar generation, have been connected to the ERCOT system, with more than 67 GW of IBRs planned or operational by 2023. Nearly 60 percent, or over 38 GW, of that IBR capacity is planned for West Texas—more than double the designed capacity for the CREZ project" (ERCOT, 2021b).

Currently, there are 38 GW of proposed wind and solar projects behind the West Texas Export interface at risk of cancellation or significant curtailment. This not only limits the ability of Texas load centers in Dallas, Austin, Houston, and San Antonio to access low-cost renewables, but also limits the ability of this resource to be exported to neighboring states. This could severely dampen a burgeoning renewable industry in Texas, reduce economic activity and jobs, and expose ratepayers in East Texas to high prices and emissions.

However, although West Texas has large renewable energy resources, there is little load or synchronous generation in the region, and the total export capability is limited by long-distance transmission to load centers. As a result, in 2020 a Generic Transmission Constraint was established to monitor and limit the total West Texas Export in order to address wide-area voltage instability challenges caused by the clustering of inverter-based technology (wind, solar, and battery storage) in West Texas, located far from end use load centers and synchronous generation from thermal power plants (ERCOT, 2020b) (Figure 6, p. 15). Specifically, sixteen 345 kV transmission lines are limited to 11 to 12.5 GW depending on the amount of inverter-based and synchronous resources online. Due to the constraint, the modeling in this study and ERCOT's own analysis indicate that 1.5 to 5 percent of all wind and solar generation in Texas is curtailed, and by 2030 this grows to 20 to 28 percent.

FIGURE 6

West Texas Export and Renewable Resource Assessment for Wind and Solar



Wind and solar resource assessment of Texas with the approximate location of the West Texas Export constraint shown as a dashed white line.

Source: National Renewable Energy Laboratory.

This study evaluated potential transmission upgrades that would allow fuller access to a renewable energy zone—both within Texas and between Texas and a neighboring region. According to the FERC NOPR, "requiring the consideration and potential identification of geographic zones within long-term scenarios assists public utility transmission providers, transmission developers, and generation developers to coordinate their activities. We believe that public utility transmission providers would be able to better identify transmission needs driven by changes in the resource mix and demand by considering geographic zones that have the potential for the development of large amounts of new generation and where developers have already shown commercial interest" (FERC, 2022, p. 126). While ERCOT is not under FERC jurisdiction, this case study is clearly relevant for other renewable energy zones across the country.

Although Texas was proactive in establishing the CREZ lines, that transmission capacity is already oversubscribed. The FERC NOPR re-establishes the need for enabling more generation from geographic zones with high energy potential (West Texas) to reach load centers (East Texas), which requires planners to realize the full economic benefits of transmission projects. The multi-value planning framework presented in this report enables planners to follow through on FERC's intent.

Modeling a Future Grid in Texas

To evaluate the benefits of large-scale transmission additions on the ERCOT system, a detailed production cost model was developed to evaluate grid operations in 2023, 2026, and 2030.[3] The production cost model was used as the basis for the additional multi-value analysis,

3 The PLEXOS economic least-cost production cost modeling software was used for all production cost modeling in this study. Probabilistic weather years and outage draws were added to the model for resource adequacy and risk mitigation simulations.

which adds probabilistic analysis for resource adequacy and resilience benefits as well as benefits external to production costs such as generation capital cost savings and emissions reductions. The years 2023, 2026, and 2030 were selected for two reasons. First, they provide snapshots of grid operations and transmission congestion on near-term, medium-term, and longer-term horizons as system changes occur—namely, additions of variable renewables, deployment of new battery energy storage, and retirements of coal and gas plants. Second, the three years selected were consistent with current transmission planning processes in ERCOT, with 2023 and 2026 being evaluated in the ERCOT *Regional Transmission Plan* (ERCOT, 2021a) and 2030 being evaluated in the ERCOT *Long-Term West Texas Export Study* (ERCOT, 2022).

As we noted above, a longer study horizon is an important aspect of system planning, and that is one limitation of this study. This study only evaluated an 8-year horizon instead of a more appropriate 20-year horizon as proposed in the FERC NOPR (FERC, 2022, p. 88), a decision made for a few reasons. It simplifies the analysis to showcase the multi-value approach, and it allows us to focus on methodologies and metrics and not spend the time and effort to build out a longer time horizon. The same methodologies can, and should, be applied to longer horizons. Macroeconomic drivers like load growth, gas price volatility, renewable and storage deployment, and thermal unit retirements were instead evaluated separately without a specific year in mind, but were made to be representative of a longer time horizon. The shorter horizon also allowed for more detailed analysis in resource adequacy simulations—a key component of this study. Finally, the time horizon was enough to significantly justify the build-out of new transmission. A longer time horizon would bring even greater transmission benefits.

A Changing Energy Mix

The study incorporated inputs and assumptions, to the extent possible, directly from ERCOT transmission planning via publicly available reports. One of the most important assumptions in the study is the amount of new capacity additions—namely solar, wind, and battery energy storage—along with retirements of gas and coal capacity. Wind and solar additions and thermal unit retirements were based on the ERCOT *Long Term System Assessment* (ERCOT, 2020a) and adjusted for recent retirement announcements and new projects in the ERCOT interconnection queue. In total, we included the addition of 25 GW of solar capacity, 29 GW of wind, and 11 GW of battery energy storage

(7 GW of hybrid storage and 4 GW of stand-alone storage). In addition, 12 GW of coal and gas capacity was retired, and no new thermal resources were added to the model. Documentation of additional inputs and assumptions are provided in the appendix, Table A-1.

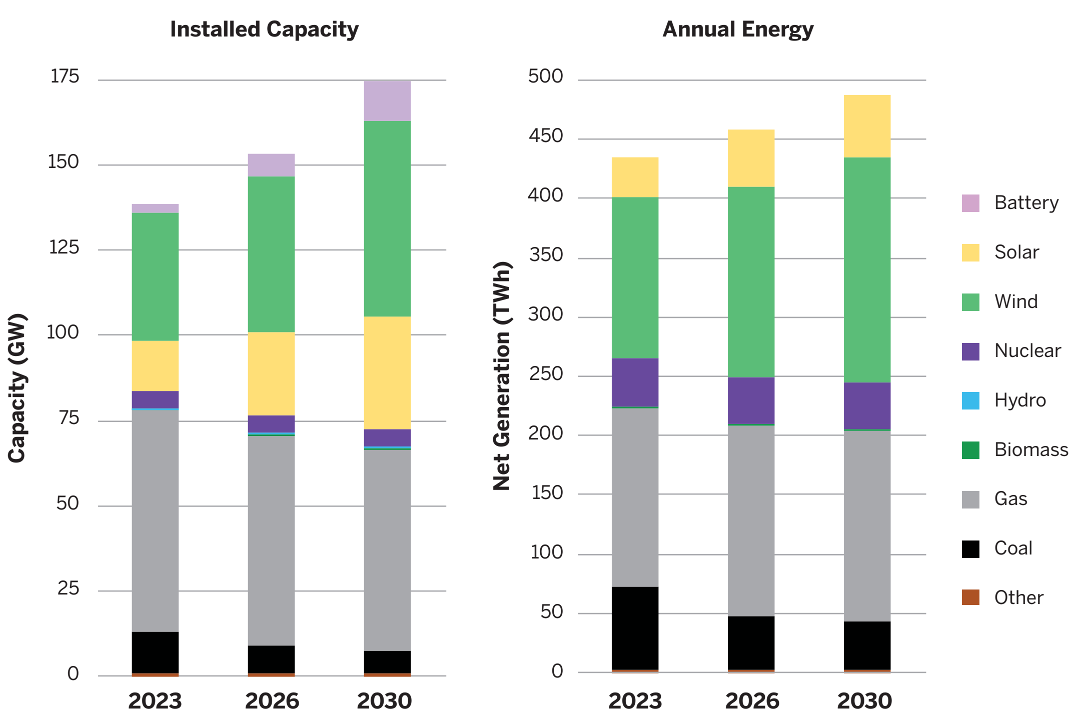
Figure 7 provides the installed capacity by fuel type (left) and the annual energy (right) for the three study years. In 2030, inverter-based resources represent 102 GW of capacity, an increase of 48 GW (87 percent) relative to the near-term 2023 ERCOT grid. This translates into a 50 percent variable renewable grid (up from 39 percent in 2023) and a 58 percent zero-carbon grid after accounting for nuclear generation.

Transmission Topology

The production cost model used a zonal transmission topology and transport model in place of a nodal topology and DC power flow. Since the West Texas Export and HVDC interties with neighboring regions are inter-zonal transmission lines, local congestion was not necessary to show the economic benefits of these projects. Our study's zonal model results compared well with recent nodal results produced by the ERCOT transmission planning team's *Regional Transmission Plan* and the *Long-Term West Texas Export Study* (ERCOT 2021a; 2022). Additionally, given that the system evaluated in the proposed 2030 scenario incorporates over 50 GW of new inverter-based resources, significant local transmission upgrades would be necessary to enable that level of build-out. This would significantly alter the nodal dataset needed for the 2030 model year, which was out of scope for this study. This decision—and simplification—was not made lightly but was determined to be appropriate for this study.

The model was divided into five transmission zones (Figure 8) and incorporated three major transmission interfaces representing the largest transmission constraints on the ERCOT system and capturing the

FIGURE 7
Installed Capacity and Annual Generation by Fuel Type for the Three Study Years Examined

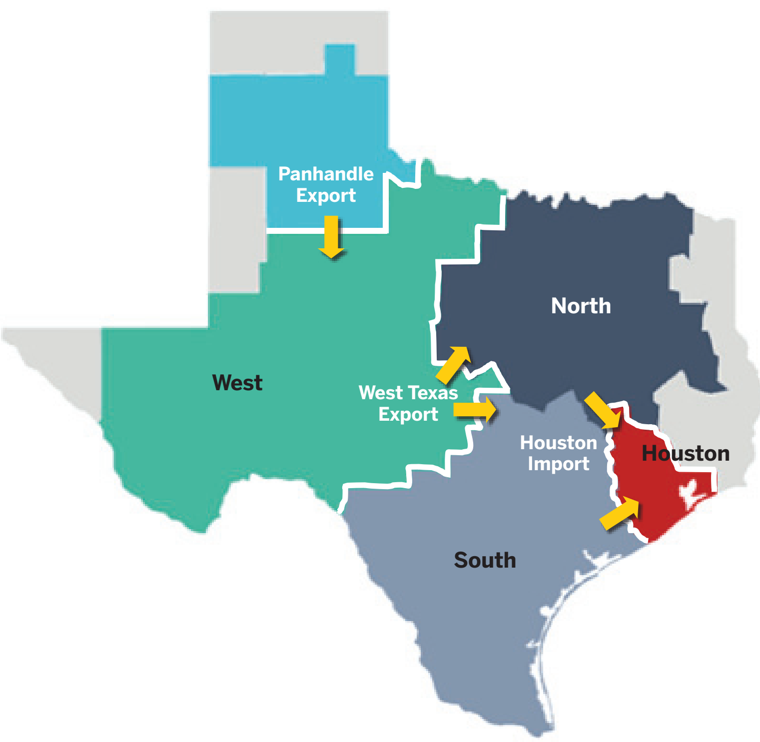


ERCOT installed capacity (left) and annual energy generation (right) by fuel type, by study year.

Source: Energy Systems Integration Group.

FIGURE 8

Transmission Topology and Zonal Interfaces



Zonal transmission topology is indicated by the colored regions, and key interfaces evaluated in this study are indicated by the white lines.

Source: Energy Systems Integration Group.

large inter-zonal limits. These interfaces include the Panhandle Export, West Texas Export, and the Houston Import. While there is notable transmission congestion within some of these zones, such as in Far West Texas and the lower Rio Grande, the study assumed that lines proposed and under construction in those regions would mitigate much of that congestion.

Selection of Benefits to Be Analyzed

When conducting regional transmission planning, it is important to clearly articulate the benefits being quantified. FERC put forth in its NOPR the recognition that determining a list of long-term regional transmission benefits may be useful for considering a portfolio of projects and their benefit-cost ratios. Although FERC provided a list of potential benefits that planners may seek to include in their assessments, the overall selection of which benefits to include and how to quantify them is left up to regional planners and regulators. The NOPR also stressed the need to identify transmission projects "driven by changes in the resource mix and demand" and explain the rationale for using the selected benefits (FERC, 2022, p. 157). Identifying which benefits to incorporate in planning analyses is a vital part of implementing the multi-value planning framework. Benefits selection is a deeply regional process that is a

TABLE 2

The Six Transmission Benefits Categories Evaluated

Benefit	Description
Production cost benefits	Quantification of fuel cost savings, reduced curtailment, variable operations and maintenance costs, reduced cycling of thermal power plants.
Emissions reduction benefits	The reduction in emissions of environmental pollutants, including CO_2, NOx, SOx.
Generation capital cost benefits	Reduced capital costs of new generating capacity and lower costs of achieving a renewable energy target from being able to access lower-cost renewable regions that are associated with better resource quality, lower land cost, and easier development.
Risk mitigation benefits	Production cost savings across a range of uncertain future conditions associated with varying gas prices, load growth, renewable build-out and thermal plant retirements.
Resource adequacy benefits	The reduction in loss-of-load expectation attributed to the transmission line, compared to the net cost of a new combustion turbine(s) necessary to achieve the same level of reliability.
Resilience benefits	The reduction in unserved energy attributed to the transmission line during the loss-of-load events remaining after resource adequacy improvements, valued at the ERCOT loss-of-load assumption of $20,000/MWh.

Source: Energy Systems Integration Group.

function of natural resources, regulatory structure, and the population. While ERCOT is not subject to regulations under FERC's NOPR, it provides a useful list of potential transmission benefits to consider.

Members of the ESIG Transmission Task Force analyzed a broad range of potential benefits for use in this study. The task force focused on six core benefits that were common across the literature (Table 2) and carefully designed the study scenarios to highlight how robust methodologies can reveal different benefits.

This case study implemented the multi-value framework across two proposed transmission portfolios, one that evaluated up to four new 345 kV AC or HVDC lines to relieve the West Texas Export constraint and a second HVDC transmission project connecting ERCOT to Southern Company in the Southeast. The former is meant to meant to enable access to high-quality, low-cost, and quickly developable renewable resource zones. The latter is meant to link geographically distant locations to improve load and resource diversity and thus improve the systems' efficiency, reliability, and resilience. The focus was on metrics that identify cost savings (both traditional production cost savings and other cost reductions), environmental goals, grid resilience, resource adequacy, and macroeconomic uncertainty, all of which could be readily quantified using output from production cost simulations and probabilistic analysis of these results. Each project was evaluated using a similar methodology, and benefits were quantified across the six categories in Table 2.

West Texas Export Transmission Benefits

To evaluate the benefits of the West Texas Export transmission upgrades, a series of production cost simulations were performed on the ERCOT system for the years 2023, 2026, and 2030 in order to quantify each benefit outlined in the previous section. The production cost analysis simulates grid operations across one year, or 8,760 hours of operation, considering unit commitment and dispatch, unit-specific heat rates and capacities, operating costs, and other generator constraints. Wind and solar generators were modeled with plant-specific generation profiles to capture the resource variability and geographic diversity.[4]

Modeling West Texas Export Upgrades

We began by characterizing a base case without new transmission and then, to isolate the impacts of the proposed transmission upgrades, two additional cases were evaluated and the value quantified for each benefit type compared to the base case. The base case assumes no new transmission lines are built to alleviate the West Texas Export constraint. The export limit is assumed to be 11,016 MW in 2023, increasing to 12,375 MW in 2030 due to additional reactive power capability from wind and solar capacity expansion behind the constraint, but not to any new line additions (ERCOT, 2022). Two transmission upgrades which would increase the transmission limit and reduce congestion were also modeled: Option 1 adds four new 345 kV AC transmission lines connecting West Texas and East Texas, and Option 2 adds three new 345 kV AC transmission lines connecting West to East Texas and one voltage source converter HVDC (VSC-HVDC) line connecting West Texas directly to the Houston load pocket (Figure 9, p. 21).

Baseline Results

Table 3 (p. 21) summarizes the applicable limits of the West Texas Export constraint under 2023, 2026, and 2030 grid conditions in the base case, as renewable capacity is added to West Texas.

As levels of inverter-based resources increase, West Texas Export congestion gets worse even when the export limit increases from 11 GW to 12.3 GW due to additional reactive power capability from more generators being on the system in West Texas by 2030. The number of hours congested increases to include more than half the year, from 1,223 to 4,815 hours (an increase of 294 percent), and congestion rent reaches almost $1.5 billion dollars annually by 2030.[5] This congestion significantly increases the total wind and solar curtailment on the system, up to 20 percent of all available renewable energy, and results in an economically inefficient system.

Conditions of the West Texas Export interface in the base case given the generic transmission constraint implemented by ERCOT show increased levels of congestion. This translates to higher wind and solar curtailment during peak production periods and an economically inefficient system.

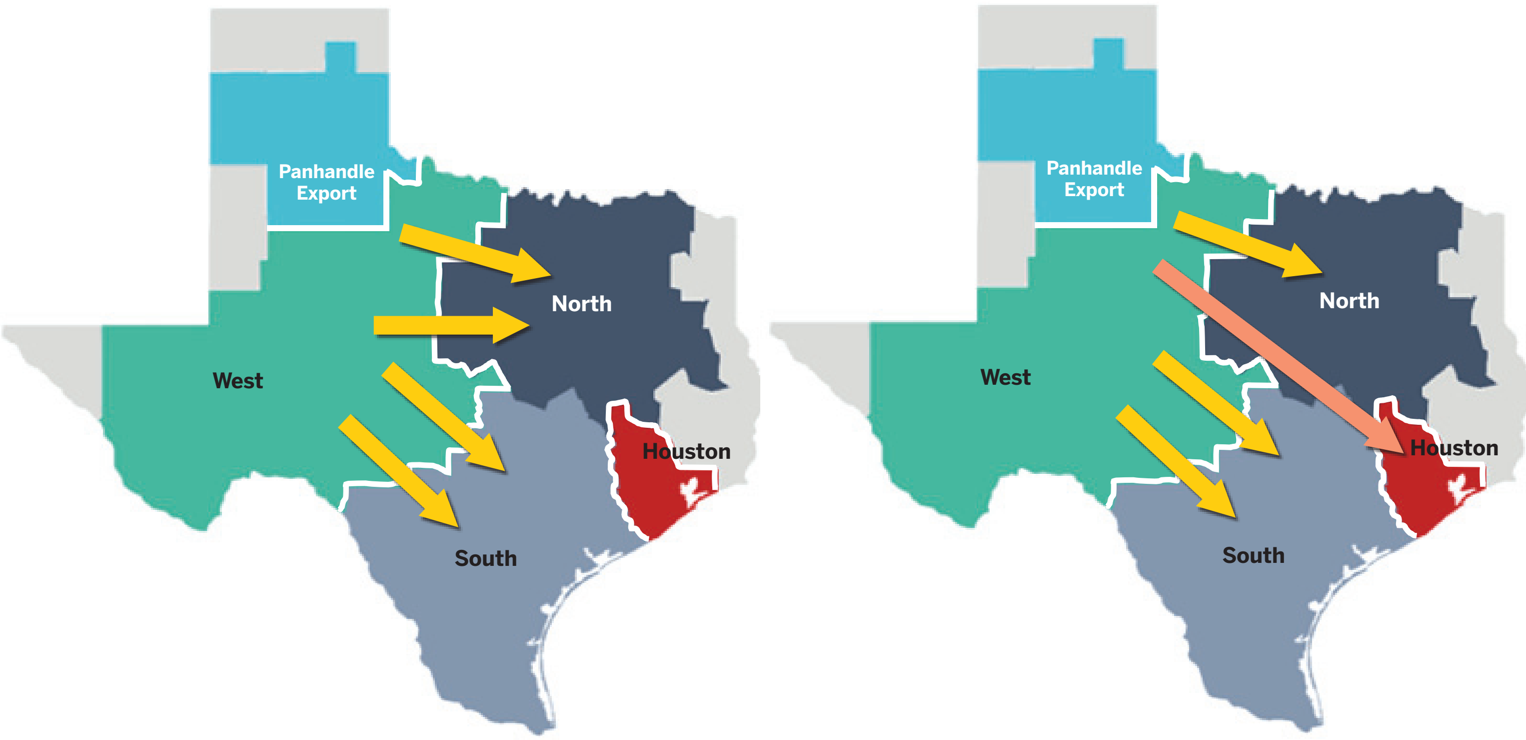
Our modeling of the hourly power flows across the West Texas Export interface showed increased congestion across the years simulated. The flow duration curve in

4 The model assumed a normal wind and solar weather year of 2013 for baseline production cost simulations, similar to ERCOT regional planning. Forty years of weather was considered for the resource adequacy and resilience analysis.

5 All dollars are reported in 2020 real $ unless otherwise noted.

FIGURE 9

ERCOT-Proposed West Texas Export Transmission Upgrade Options



Zonal transmission topology is indicated by the colored regions, and key interfaces evaluated in this study are indicated by the white lines. The transmission lines evaluated are represented as yellow (AC) and orange (DC) arrows.

Source: Electric Reliability Council of Texas (2022).

TABLE 3

West Texas Export Constraint, Summary of Base Case Results

West Texas Export Performance	2023	2026	2030
Inputs and Assumptions			
Export limit*	11,016 MW	11,670 MW	12,375 MW
Installed IBR capacity	32,399 MW	48,651 MW	66,160 MW
Simulation Results			
Congestion rent (2020 $)	$268 million	$872 million	$1,411 million
Hours congested	1,223 hours	3,606 hours	4,815 hours
Percentage of hours congested	14%	41%	55%
Wind and solar curtailment	2,789 GWh	21,106 GWh	59,406 GWh
Wind and solar curtailment	1.6%	9.2%	19.7%

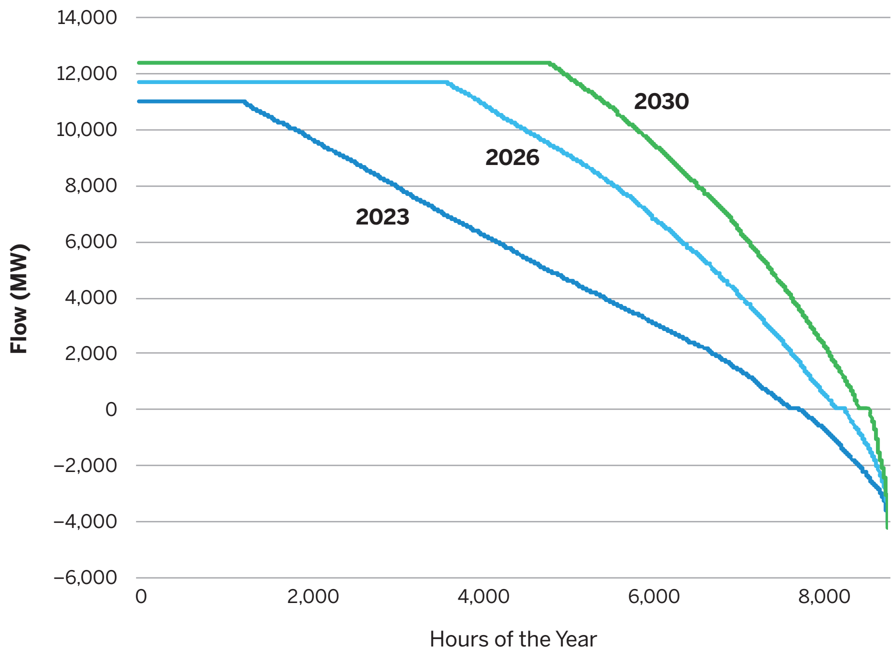
Conditions of the West Texas Export interface in the base case given the generic transmission constraint implemented by ERCOT show increased levels of congestion. This translates to higher wind and solar curtailment during peak production periods and an economically inefficient system.

* Export limit represents 90% of the stability limit, which is consistent with ERCOT planning.

Source: Energy Systems Integration Group.

FIGURE 10

West Texas Export Base Case Flow Duration Curves, 2023, 2026, and 2030



Hourly line flows across a year of operation, sorted from highest to lowest, illustrate congestion on the West Texas Export interface. The changing shape of the curve as one moves from 2023 to 2026 to 2030 shows an increasing number of hours in the year where flow across the interface is capped at the generic transmission constraint export limit.

Source: Energy Systems Integration Group.

Figure 10 shows the hourly flows across the West Texas Export interface, sorted from high to low. It also indicates a significant increase in flows across the remaining, uncongested hours. In 2023 there are approximately 1,000 hours of reversed flow (from North Texas to West Texas), but this is nearly eliminated by 2030 due to the growth of West Texas renewables providing consistent surplus energy available to flow from west to east. Total flow across the transmission line (the area under the curve) increases markedly, from 47,895 GWh and 51 percent loading of the interface in 2023, up to 85,424 GWh and 79 percent loading of the interface in 2030, highlighting a significant need for new transmission to accommodate the large amounts of energy available in West Texas.

Two Transmission Upgrades Modeled

To quantify the value of relieving the transmission congestion, this study evaluated two transmission upgrades to the West Texas Export and compared them to the base case. The transmission upgrades evaluated were drawn from ERCOT's recent analysis which evaluated several transmission upgrade options in its recent *Long-Term West Texas Export Study* (ERCOT, 2022). Option 1 and Option 2 from the study were chosen to represent two avenues for alleviating the West Texas Export constraint in this study. Option 1 adds four new 345 kV AC transmission lines connecting West Texas to East Texas, increasing the total transfer capability by 4,140 MW in 2030. Option 2 adds three new 345 kV AC transmission lines connecting West Texas to East Texas and one VSC-HVDC line connecting West Texas directly to the Houston load pocket, increasing the total transfer capability by 4,527 MW in 2030.

We developed high-level, generic cost assumptions for new transmission build-out, based on the voltage, length, and type of transmission additions. No analysis was conducted for site-specific transmission additions, but the results provide a reasonable estimate of new transmission costs. Transmission costs were estimated at one dollar per mile for 345 kV AC transmission lines and 500 kV VSC-HVDC lines and stations. Estimates for 345 kV AC lines were based on historical and projected 345 kV transmission project cost and mileage reported in the ERCOT *Transmission Project and Information Tracking* from October 2021 (ERCOT, 2021c). The 500 kV VSC-HVDC line and station estimates are based on MISO's 2021 *Transmission Cost Estimation Guide* for HVDC in Texas (MISO, 2021).

The upgrade costs were annualized to compare against annual benefits from the simulations using a capital recovery factor (CRF) approach. The CRF is a simplified conversion of a total upfront capital expenditure into annualized costs to reflect the costs of financing a project and is based on the interest rate assumptions and the assumed economic life of the project. This process allows for direct comparison against the annual benefits. The interest rate was set to 10 percent based on the proxy weighted average cost of capital referenced in the Public Utility Commission of Texas' Costs, Rates and Tariffs Subchapter J, Section E (PUCT, 2008). Since transmission assets provide benefits over many decades, the lifetime of the investment was set to 30 years. This resulted in a 10.6 percent CRF: every $1 billion in capital costs translates to $106 million per year, spread across 30 years. Table 4 summarizes each option's total costs, and Table 5 provides the final annualized capital costs.

TABLE 4

Estimated Total Costs for Transmission Upgrade Options

Transmission Upgrade Cost Estimates	Option 1 (4 AC Lines)	Option 2 (3 AC Lines + 1 HVDC Line)
Estimated circuit miles	1,027 miles	721 miles (AC) and 545 miles (HVDC)
Cost per mile	$2.86 million	$2.86 million (AC) and $2.84 million (HVDC)
Voltage source converter stations	—	$1.076 billion
Total cost	$2.9 billion	$4.7 billion

The cost for each transmission upgrade option for the West Texas Export is broken into a general $/mile cost for lines and cost for HVDC substations. Option 2 (with the HVDC line to Houston) is more expensive than Option 1 given the added cost of the HVDC voltage source converter stations.

Source: Energy Systems Integration Group.

TABLE 5

Annualized Cost Estimates for Transmission Upgrade Options

Annualized Transmission Upgrade Costs	Option 1 (4 AC Lines)	Option 2 (3 AC Lines + 1 HVDC Line)
Weighted average cost of capital (WACC)	10%	10%
Investment lifetime	30 years	30 years
Capital recovery factor	10.6%	10.6%
Annualized upgrade cost estimate (2020$)	$312 million	$498 million

The transmission costs are converted to an annual value to account for the required payback period for the investment. A simplified capital recovery factor is used to convert the upfront costs to a 30-year annual investment cost.

Source: Energy Systems Integration Group.

The cost for each transmission upgrade option for the West Texas Export is broken into a general $/mile cost for lines and cost for HVDC substations. Option 2 (with the HVDC line to Houston) is substantially more expensive than Option 1 given the added cost of the HVDC voltage source converter stations.

Production Cost Benefits

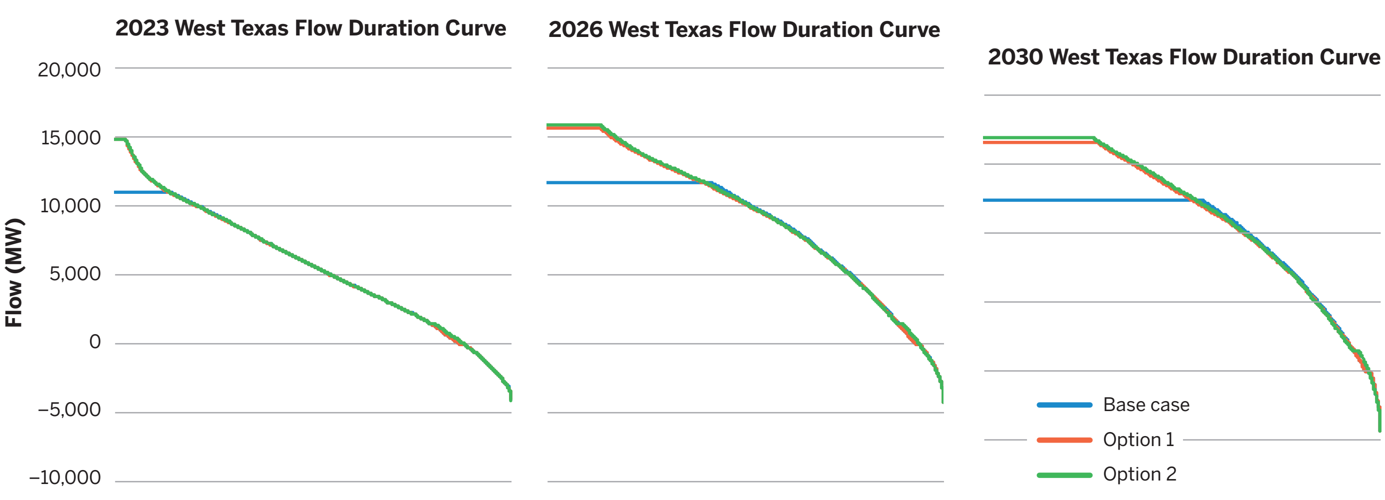
The first benefit evaluated was production cost savings, the de facto planning used across most transmission planning analyses today. While this report clearly shows the advantages of using a multi-value framework, production costs remain an integral part of transmission planning if evaluated alongside other benefits.

Production cost savings attributed to the West Texas Export transmission upgrades are directly related to the reduction in congestion, reduction in curtailment of wind and solar generation, and reduction in loading of the West Texas Export constraint. Changes in these factors indicate that greater amounts of zero-marginal-cost electricity, produced by wind and solar, are exported from west to east because of the transmission upgrades, which means that fewer more expensive resources in East Texas are needed to satisfy demand.

Reduced Congestion

The model shows that implementing both transmission upgrade options results in the immediate relief of the West Texas Export constraint, with reduced congestion and a lower average line loading (another indicator of electricity flows not meeting or exceeding the line limits) over the study horizon. Figure 11 shows the flow over the West Texas Export interface for 2023, 2026, and 2030. The transmission upgrade cases, Options 1 and 2, result in higher flows than in the base case during congested hours and limited or no changes in flow in the remainder of the year. This finding makes sense because during periods when the transmission line is not congested, export flows from west to east (or east to west) is a function of available generation capacity on the system. Increasing the transmission limits does not add new capacity but frees up constrained capacity in high production hours. As an increasing number of renewable plants are built behind the West Texas Export constraint by 2030 (approximately 33 GW), the interface is congested much less often: approximately 30 percent of the time compared to 56 percent of the time under base case conditions.

FIGURE 11
West Texas Export Upgrade Options, Flow Duration Curve Comparison to Base Case



The flow duration curves for each study period year and transmission configuration (base case, Option 1, and Option 2) show that Options 1 and 2 relieve the congestion to a similar degree. When the orange line is not visible, it is behind the green line, representing similar interface flows between the two options.

Source: Energy Systems Integration Group.

The decreased congestion yields significant benefits. Table 6 summarizes the base case results against each upgrade option using congestion, curtailment, and loading characteristics for the West Texas Export interface. Included is the congestion on the Houston Import interface used to highlight downstream impacts and to differentiate between the benefits for upgrade Option 1 and Option 2. For example, transmission imports into the Houston area are also constrained by ERCOT-specified transfer limits. Under Option 1 (4 AC lines), greater flows of electricity from west to east encounter this additional constraint when flowing into Houston, shown by the almost identical congestion levels between the base case and Option 1. Option 2 (3 AC lines + 1 HVDC line), however, shows a reduction in congestion for Houston. This is because the HVDC transmission line bypasses the existing AC transmission network into Houston, providing relief for two congestion interfaces at once.

Reduced Curtailment of Wind and Solar

Our results also showed that reduced congestion in West Texas led to reduced curtailment of wind and solar units. This translated to a seasonal shift in generation by resource type concentrated in the spring and fall months. Renewable generation is typically higher in the spring months (mainly driven by wind in Texas) and load is often lower, so it is expected that curtailment due to congestion on the transmission lines would occur during these months. By increasing export capacity from West Texas, there is a more pronounced increase in wind and solar generation during the peak production seasons, resulting in less fossil fuel generation during those months. Congestion still occurs throughout the year, but the benefits of increased export capacity are less significant in the summer, fall, and winter months. Figure 12 (p. 26) shows the delta between monthly generation by wind, solar, gas, and coal units for upgrade Option 1 (4 AC lines) compared to the base case. By 2030, upgrade Option 1 reduces annual fossil generation by 13,000 GWh, allowing lower-cost solar and wind generation to displace higher-cost gas and coal.

As a result of the increase in solar and wind exports from west to east, the total production cost across ERCOT was reduced. The savings for each of the two upgrade options are summarized in Table 7, p. 26) and Figure 13, p. 27). It is clear that neither transmission upgrade option is economically justifiable when considering production cost savings alone in 2023 or 2026. It is only

TABLE 6

Detailed Performance Characteristics of West Texas Export, With and Without Upgrades

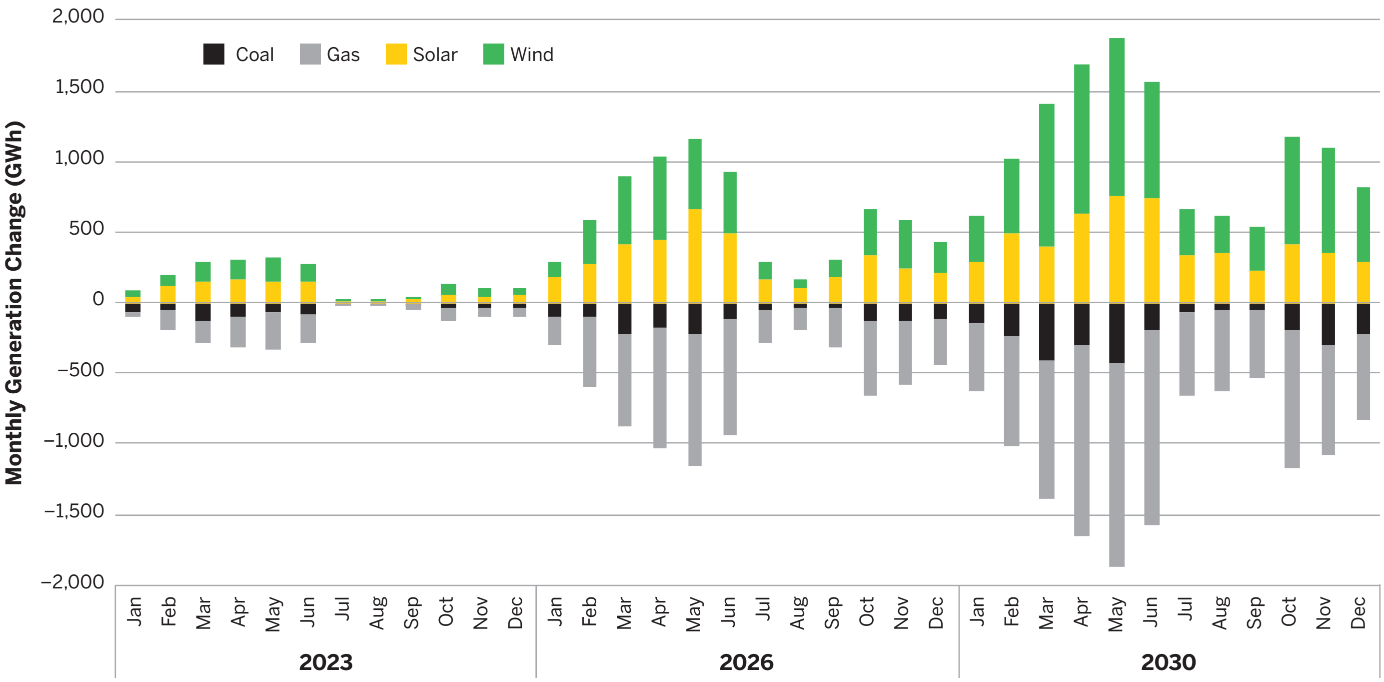
Property	Unit	2023			2026			2030		
		Base Case	Upgrade Option 1	Upgrade Option 2	Base Case	Upgrade Option 1	Upgrade Option 2	Base Case	Upgrade Option 1	Upgrade Option 2
Export limit	MW	11,016	14,814	14,841	11,670	15,633	15,833	12,375	16,515	16,902
Hours congested	H	1,223	229	244	3,606	1,189	1,195	4,815	2,529	2,391
Hours congested	%	14	2.6	2.8	41	13.6	13.6	55	28.9	27.3
Loading	%	51	40	40	71	59	59	79	69	68
Congestion rent	$MM	257	59	64	838	346	347	1,356	813	774
Shadow price	$/MW	2.67	0.46	0.50	8.20	2.53	2.51	12.51	5.63	5.23
Curtailment	%	1.6	0.5	0.5	9.2	6.0	5.8	19.7	15.4	15
Houston congestion	%	29	30	6	61	63	29	87	87	63

A comparison of West Texas Export upgrade options relative to the base case shows similar relief on congestion through the West Texas Export interface (2020 dollars). In addition, Option 2 also alleviates some congestion on the Houston Import interface, which is an added benefit of the HVDC link between West Texas and Houston.

Source: Energy Systems Integration Group.

FIGURE 12

Monthly Change in Generation by Type, Upgrade Option 1 Compared to Base Case



Change in monthly generation by fuel type after the Option 1 transmission upgrade is added to the system. Positive values indicate increased generation from previously curtailed wind and solar, while negative values show displaced generation from coal and gas.

Source: Energy Systems Integration Group.

TABLE 7

Production Cost Savings and Capital Cost Comparisons Relative to Base Case, by Study Year

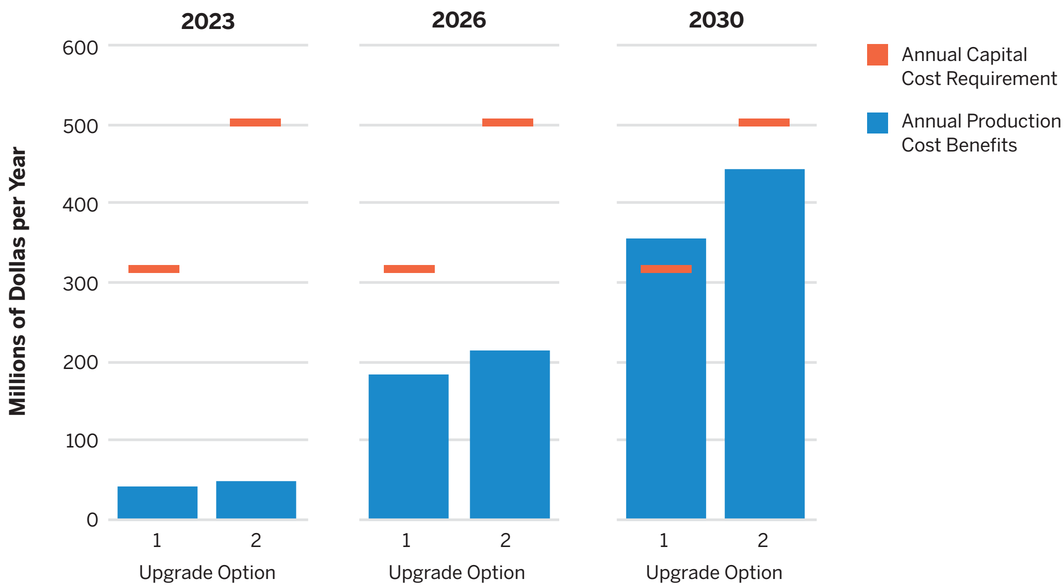
Transmission Upgrade	2023		2026		2030	
	Option 1	Option 2	Option 1	Option 2	Option 1	Option 2
Upgrade capital cost estimate	\$2.9 billion	\$4.7 billion	\$2.9 billion	\$4.7 billion	\$2.9 billion	\$4.7 billon
Annualized capital cost	\$312 million	\$498 million	\$312 million	\$498 million	\$312 million	\$498 million
Production cost savings	\$42 million	\$49 million	\$184 million	\$215 million	\$356 million	\$443 million
Annual net benefit	−\$270 million	−\$449 million	−\$128 million	−\$282 million	\$44 million	−\$55 million

A comparison of production costs to annualized capital costs show large negative net benefits (costs) in early years, rising to break-even in 2030. The difference between production cost savings and annualized capital costs produce the annual net benefits for each option.

Source: Energy Systems Integration Group.

FIGURE 13

Annual Costs and Benefits by Upgrade Option and Year, for Production Cost Benefits Alone



A comparison of production costs to annualized capital costs show large negative net benefits (cost) in early years, rising to break-even in 2030.

Source: Energy Systems Integration Group.

on a slightly longer-term horizon, out to 2030, that the traditional production cost benefits for Option 1 are positive (while Option 2 remains negative). This reinforces the idea that if transmission planning studies are to accurately quantify the benefits of new large-scale transmission, they must account for long-term trends in generation supply changes in order to adequately assess production cost savings benefits. A proactive planning approach is especially important when large-scale transmission projects require substantial planning and development efforts.

Key Takeaways

The results indicate that, from solely a production cost perspective, Option 1 (4 AC lines) is more economic, having positive annual net benefits and a lower cost compared to Option 2 (3 AC lines + 1 HVDC line). However, while the longer HVDC line to Houston makes Option 2 more expensive to build, looking beyond strictly production cost savings, additional benefits may be realized related to risk mitigation, emissions reductions, resource adequacy, and resilience. It is necessary to address the incremental value ascribed to these additional criteria for each option in order to understand the full spectrum of transmission benefits.

Perhaps the most important result provided in Figure 13 is the significant change in benefits across the study horizon. The increasing benefits evaluated over time show the growing value of new transmission on a future power system with increased renewable capacity, and highlights the importance of using a long-term study horizon. Transmission is a long-term investment, thus the modeling should evaluate a long-term horizon, ideally 20 years or more. While this study did not evaluate benefits out to 2040 or later, the positive benefit-cost ratio observed in 2030 is expected to become continually more pronounced in a future system with increased renewables, load, and higher fuel prices.

Emissions Reduction Benefits

A second benefit evaluated by the study is avoided emissions. Technically speaking, if the emissions have a price (like nitrogen oxides (NOx) and sulfur oxides (SOx)), this is a production cost benefit. However, for the purposes of this report, the emissions benefits are evaluated separately in order to align our results with environmental policy goals and to evaluate a social cost of carbon, which is not priced in most markets. This approach captures some of the public policy benefits associated with clean energy goals. As the share of renewables grows, transmission development presents opportunities to bring emissions-free resources to load centers, which provides value to the system and should be accounted for in transmission planning.

This study quantified reductions in NOx, SOx, and CO_2 emissions as a result of the West Texas Export upgrades using historical market prices for the Environmental Protection Agency's Cross-State Air Pollution Rule (CSAPR) pollutants (NOx and SOx), the Texas Commission on Environmental Quality's Mass Emissions Cap and Trade Program for NOx, and the Energy Information Administration's (EIA) future CO_2 price scenarios.

CO_2 Emissions Reduction

Although there are currently no carbon emissions regulations in Texas, at either the state or the federal level, there are increasing calls from some corporations and governments to reduce carbon emissions and eventually decarbonize completely. Several benefits of reduced CO_2 emissions from the grid are:

- Increased corporate investment due to values alignment with climate-conscious entities
- Health benefits from reduced associated pollutants (particulate matter, NOx, SOx, mercury)
- Economic hedging against potential carbon regulations (both for electricity and industrial exports)

While quantifying the full range of societal benefits from CO_2 emissions reduction was beyond the scope of this study, three carbon price scenarios were chosen from the recent EIA CO_2 price analysis to provide a benefits range in terms of avoided tons of CO_2 emissions and the value of this attributable to the transmission upgrades (EIA, 2021a). The CO_2 prices start in 2023 at $15, $25, and $35 per metric ton and rise at 5 percent per annum until 2050. The avoided cost of CO_2 emissions was calculated using total emissions output from electricity generation from the models and inflation-adjusted 2020$ CO_2 prices for each study year. By 2030, the CO_2 prices reach $17, $29, and $40 per metric ton.

Table 8 summarizes the range of avoided CO_2 emissions and savings for each transmission option relative to the base case. In the base case, CO_2 emissions decrease over time as the share of renewables in ERCOT grows and more fossil units are retired. The transmission upgrades studied provide savings on top of base case reductions by reducing curtailment of wind and solar units behind the West Texas Export constraint and bringing more zero-emissions energy to ERCOT load zones.

TABLE 8

Avoided CO_2 Emissions Benefits by Upgrade Option and Model Year for EIA Price Scenarios

Year	Annual CO_2 Emissions (thousand metric tons)			$15 CO_2 Savings (2020 M$)		$25 CO_2 Savings (2020 M$)		$35 CO_2 Savings (2020 M$)	
	Base Case	Option 1	Option 2	Option 1	Option 2	Option 1	Option 2	Option 1	Option 2
2023	126,524	125,430	125,537	15	14	25	23	36	32
2026	106,399	102,750	102,807	56	56	94	93	132	130
2030	84,906	79,296	78,910	113	117	188	194	263	272

The West Texas Export upgrades reduce annual CO_2 emissions by one to six million metric tons per year, translating to $15 million to $272 million in annual benefits depending on the assumed CO_2 price.

Source: Energy Systems Integration Group.

NOx and SOx Emissions Reduction

Texas is a member of the EPA CSAPR Group 2, which regulates NOx and SOx emissions under a cap-and-trade system. Texas also has its own NOx emissions trading program under the Texas Commission on Environmental Quality for the Houston-Galveston-Brazoria area. Prices from each of these trading markets were used to quantify the value of reduced NOx and SOx emissions as a result of the two transmission upgrade options, Option 1 and Option 2. In the case of CSAPR Group 2 NOx ozone season prices, the price used was indicative of the average price per allowance prior to the EPA CSAPR update. Our choice of this price was to avoid over-valuing the NOx seasonal emissions reductions due to recent emissions program changes and price volatility that is expected to resolve.[6]

The Texas Commission on Environmental Quality's NOx price was determined by taking the commission's Mass Emissions Cap and Trade Program's trading report data from 2018 through 2020 and developing a weighted price based on the total tons of NOx allowances traded at different price levels over those years (TCEQ, 2020). Emissions reductions for the Mass Emissions Cap and Trade Program were only calculated for reduced NOx emissions from generators located in the Houston zone. Table 9 summarizes the emissions type, price, and reduction in tons, and the total emissions benefit. All emissions levels and benefits are for the 2030 model year. Note that these benefits do not incorporate associated health benefits, which are instead captured in the CO_2 emissions reduction section. Avoided NOx and SOx emissions translate to approximately $11 million per year in additional benefits for Option 2 based on recent emissions prices.

Generation Capital Cost Benefits

The generation capital cost savings are defined as the total reduction in capital cost attributed to siting wind and solar capacity in lower-cost regions that would not have been possible without transmission expansion. Because West Texas has some of the best wind and solar resources in the country, new transmission that unlocks this potential should be evaluated against this public policy benefit. Without transmission development, commercial renewable developers would have to shift prospecting farther east to avoid potential curtailment

TABLE 9

NOx and SOx Emissions Prices and Benefits for Transmission Upgrades for the 2030 Model Year

Emissions Type	Price	Option 1 Reduction	Option 1 Benefit	Option 2 Reduction	Option 2 Benefit
NOx, annual	$2.5/ton	3,531 tons	$8,827	3,229 tons	$8,073
NOx group 2 ozone, seasonal	$70/ton	1,106 tons	$77,391	1,320 tons	$92,407
SOx group 2	$2.4/ton	2,780 tons	$6,672	1,518 tons	$3,642
TCEQ MECT NOx	$5,522/ton	5.1 tons	$28,274	1,973 tons	$10,896,532

Avoided NOx and SOx emissions translate to approximately $11 million per year in additional benefits for Option 2 based on recent emissions prices.

Note: TCEQ MECT = Texas Commission on Environmental Quality Mass Emissions Cap and Trade Program

Source: Energy Systems Integration Group.

6 Recently, CSAPR Group 2 was split into Group 2 and Group 3, each with its own emissions credits. However, for a short time, Group 2 credits can be purchased and converted by Group 3 entities into Group 3 credits at a high conversion ratio, which increased demand for Group 2 credits, raising the price significantly. These price increases are expected to be temporary in the long term as the credit market adjusts to the inclusion of the new CSAPR Group 3 (EM, 2021). The creation of the CSAPR Group 3 included a provision where Group 3 entities could buy and convert Group 2 credits into new Group 3 credits at an 8:1 ratio until August 12, 2021, and at an 18:1 ratio until March 1, 2022. These high conversion ratios and cut-off for conversion allowance has pushed prices up in recent years. It is expected that after finalization of the conversions the Group 2 credit market should stabilize to average prices before the update was enacted.

of their projects due to the West Texas Export constraint. This is already being seen in ERCOT's interconnection queues. In December 2020—around the time the West Texas Export Generic Transmission Constraint went into effect—45 percent of all new wind and solar resources were proposed in West Texas (ERCOT, 2020c). One year later, in December 2021, that number had dropped to 35 percent of the total as developers shifted to opportunities elsewhere in the state (ERCOT, 2021d).

Despite the importance of accessing renewable energy zones for meeting clean energy targets and supporting a burgeoning renewable energy industry in the state, current methods used by ERCOT and other transmission planners do not quantify the generation capital cost benefits of new transmission. The FERC NOPR recently prioritized the need to account for enabling resource development in geographically favorable areas by stating, "public utility transmission providers would be able to better identify transmission needs driven by changes in the resource mix and demand by considering geographic zones that have the potential for the development of large amounts of new generation and where developers have already shown commercial interest" (FERC, 2020, p. 126).

The generation capital cost savings quantified in this study account for the different capital costs (as opposed to production costs) of developing wind and solar resources across Texas. These costs are different due to the amount of capacity that is required to generate a similar amount of electricity (i.e., lower capacity factors in East Texas), differences in land costs, and differences in the speed and ease of developing projects.

Lower Levelized Cost of Energy in West Texas than East Texas

We used the levelized cost of energy (LCOE) to assess the difference in total cost of building wind or solar resources in different regions in Texas. The LCOE metric incorporates many variables including land costs, construction costs, and resource potential over the lifetime of a power plant, and provides a $/MWh cost of electricity which is often used for cost comparison between power plant technologies and projects. This study did not conduct a detailed LCOE analysis across Texas, but instead relied on a publicly available dataset produced by the University of Texas at Austin that calculates the overnight capital cost (the total construction cost in $/kW as if the project were completed overnight) and the LCOE of wind and solar resources for each county.[7] This dataset assumes regional cost multipliers for capital cost of equipment and takes into account the underlying weather resource (Rhodes et al., 2017).[8]

Figure 14 (p.31) provides the resulting wind (left) and solar (right) LCOE for each county in Texas, with darker colors indicating higher development costs. As the figure illustrates, LCOE is approximately $15/MWh (30 percent) lower for wind and $5/MWh (12 percent) lower for solar in West Texas compared to East Texas. All other things being equal, the same amount of renewable energy developed in West Texas would cost less than development in East Texas. This is true even without accounting for the ease of developing large, utility-scale projects in West Texas, which has much lower population density and fewer conflicting land uses.

A Shift in New Renewable Capacity from West to East, Increasing Capital Costs

The generation capital cost benefits are a reduction in capital costs for building wind and solar by siting resources in lower-cost regions versus higher-cost ones. This creates a more economically efficient system where resources built with reduced costs allow for lower-priced power purchase agreements and lower electricity bills for consumers. This benefit will be increasingly important as grid planners and developers around the country seek to provide the most renewable energy possible for the most economic price.

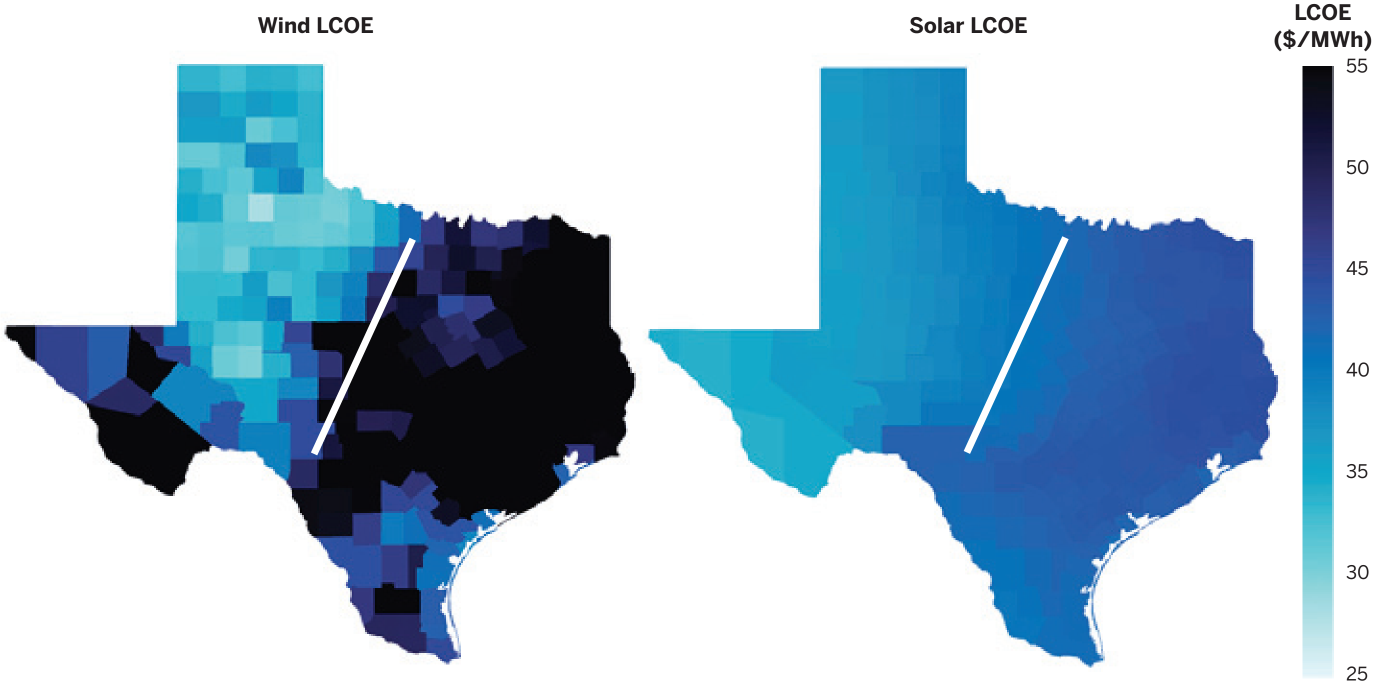
While this study did not quantify a firm limit of additional wind and solar available in West Texas without new transmission, it used the curtailment results for the base case as a guide for when new capacity would need to shift eastward to higher-price regions to avoid curtailment. It was assumed that no capacity would move in 2023 because curtailment levels were relatively low, but

7 The Energy Institute at the University of Texas at Austin, Levelized Cost of Electricity in the United States by County, version 1.4.0. https://calculators.energy.utexas.edu/lcoe_map/#/county/tech.

8 This is intended to be a screening analysis only. Additional analysis should also consider land costs and development costs (due to failed projects, community acceptance, and local transmission).

FIGURE 14

LCOE for Wind and Solar by County in Texas



Statewide levelized cost of energy comparisons by county indicate that wind resources, on average, are $15/MWh lower in West Texas compared to East Texas. Solar is $5/MWh cheaper.

Source: Energy Systems Integration Group. Data: Energy Institute at the University of Texas at Austin.

that 33 percent and 66 percent of incremental capacity would shift in 2026 and 2030, respectively. It was assumed that both the base case siting (predominantly in West Texas) and the shifted siting to the east were performed in a manner that kept the total available energy from new renewable resources in the two cases equal.

As Table 10 (p. 32) shows, this shift to the east translates to fewer new wind and solar resources sited in West Texas, with a total shift of 5.7 GW of capacity (16,417 GWh of energy) in 2026 and 13.5 GW of capacity (40,476 GWh of energy) in 2030 compared to the base case siting. As a result, to get the same amount of renewable energy without the addition of new transmission to relieve the West Texas Export constraint would require an additional $179 million per year in 2026 and $493 million per year in 2030. Put differently, the generation capital cost savings benefits are $179 million per year in 2026 and $493 million per year in 2030. These savings from siting renewable resources in the locations with the best resource is a benefit that should be ascribed to the transmission line. There are significant land use benefits that can be realized by selecting higher-quality resources. Because the installed capacity must increase to equal the same amount of energy production, the land use requirements for a future that does not expand the West Texas Export constraint could be non-trivial.

Risk Mitigation Benefits

Grid planning and modeling suffer from the same issue that all projections face: there is no such thing as perfect foresight. Gas prices, load, renewable generation, and plant retirements have been extremely volatile and relatively hard to predict, which presents a risk to grid planners in achieving the lowest production cost outcomes and leaves the grid and consumers exposed to additional risks arising from macroeconomic uncertainty in fuel prices and load. The standard approach to addressing this uncertainty on the grid has been to develop scenarios that represent a range of macroeconomic assumptions around new generation, retirements, commodity prices, and load growth. A scenario is a set of input assumptions into planning models. A classical approach may be to create three fuel price forecasts with low, medium, and high growth in prices and use these inputs with different planning portfolios to see how the value of the portfolio changes under different assumptions. This basic approach is beneficial in viewing a few different futures, but does not capture volatility within each scenario. It also does not account for the probability of each scenario occurring.

Employing a Probabilistic Approach

This study uses a statistically robust probabilistic approach for key input assumptions such as gas prices and load forecasts, for example. This approach is consistent with industry-leading practices and is available from a variety of software vendors. It is important for regulators and system planners to not only emphasize the modernization of technology used to generate electricity, but also modernize the software to design and operate these systems. Probabilistic evaluations of assumptions will aid planners in understanding a broader range of futures to more accurately value the portfolio of projects they are considering for development.

This report focuses on adding probabilistic sampling of supply-side scenarios for the load forecast and gas price levels across millions of modeling hours. To do this, probability distributions for load and gas levels were added to the production cost model, which samples

TABLE 10

Generation Capital Cost Savings from West Texas Export Transmission Upgrades

			2026			2030		
			Wind	Solar	Total	Wind	Solar	Total
[A]	West Texas installed capacity (GW)	Baseline assumptions*	31.3 GW	18.4 GW	49.7 GW	41.5 GW	28.7 GW	70.2 GW
[B]		Capacity shifted east, no new transmission	2.3 GW	3.4 GW	5.7 GW	6.8 GW	6.8 GW	13.5 GW
[C] = [A - B]		West Texas capacity remaining	29.0 GW	15.0 GW	44.0 GW	34.8 GW	21.9 GW	56.7 GW
[D]	West Texas available energy (GWh)	Baseline assumptions*	119,836 GWh	40,259 GWh	160,095 GWh	163,878 GWh	57,544 GWh	221,422 GWh
[E]		Energy shifted east, no new transmission	9,686 GWh	6,731 GWh	16,417 GWh	29,068 GWh	11,408 GWh	40,476 GWh
[F] = [D - E]		West Texas energy remaining	110,150 GWh	33,528 GWh	143,677 GWh	134,810 GWh	46,136 GWh	180,946 GWh
[G]	LCOE ($/MWh)	West Texas	33 $/MWh	36 $/MWh		33 $/MWh	36 $/MWh	
[H]		East Texas	48 $/MWh	41 $/MWh		48 $/MWh	41 $/MWh	
[I] = [H - G]		Additional cost in East Texas	15 $/MWh	5 $/MWh		15 $/MWh	5 $/MWh	
[J] = [I * F * -1]	Generation capital cost benefits (M$)		145 $/MWh	34 $/MWh	179 $/MWh	436 $/MWh	57 $/MWh	493 $/MWh

A comparison of wind and solar capital costs if capacity is shifted from West Texas to East Texas while holding the total amount of renewable energy constant.

* Note: Baseline assumption uses the wind and solar build-out predominantly in West Texas, based on the ERCOT West Texas Special Study and interconnection requests.

Source: Energy Systems Integration Group.

FIGURE 15

Number of Future Scenarios Used in the Risk Mitigation Analysis

3	Renewable & Retirement Levels
x40	Stochastic Gas Price & Load Levels
120	Different Futures Evaluated

OVER 1 MILLION HOURS OF CHRONOLOGICAL MODELING

Source: Energy Systems Integration Group.

combinations of high/low load and gas prices randomly based on probabilities assigned to each level (see Figure 16, p. 35). While there is some likely correlation between inputs—for example, high gas prices could be a function of higher load which translates to higher gas demand and higher prices—a stochastic approach allows planners to see a wide range of potential conditions rather than developing singular point estimates.

Reflecting on the gas price example, if a planner is considering a medium gas price forecast where prices remain around $2.50–$4.50/MMBtu, then gas resources may consistently be cost-effective resources. However, price volatility and market uncertainty within that medium gas-price forecast could have days, months, or years of higher prices that the single forecast misses because the average forecast smooths over this volatility.

According to the FERC NOPR, "in long-term regional transmission planning, the number and range of long-term scenarios developed determines the scope of possible future conditions for the electric power system and allows public utility transmission providers to identify the transmission needs for each possible future reflected in the scenarios. Developing a range of scenarios with different assumptions allows public utility transmission providers to consider a variety of potential scenarios and associated transmission needs driven by changes in the resource mix and demand and, in turn, possibly different regional transmission facilities to more efficiently or cost-effectively meet those needs" (FERC, 2022, p. 104).

Scenarios Modeled and Futures Evaluated

Our modeling was conducted across three renewable and thermal plant retirement scenarios, each applied to the 2030 study year. The scenarios included a range of values for amounts of renewable generation and storage additions, coal and gas plant retirements, and probabilistic load and gas prices, for a total of 120 different futures (Figure 15). While studies of this complexity and intensity would have been difficult to run a decade ago, new data sets, modern planning tools, and computational improvements allow for a significant increase in our understanding of power system risks.

Resource Mix Scenarios

Three renewable, storage, and retirement levels were developed to track broad assumptions in the resource mix by 2030. They are the base case renewable, storage, and retirements scenario; the low-renewables and storage and low thermal retirements scenario; and the high-renewables and storage and high thermal retirements scenario. An adjustment factor of 50 percent was applied to the base renewable and storage builds, resulting in approximately 30 GW of renewables and storage being added or removed relative to the base case. The low estimate of thermal retirements was based on fixed-age retirements from the *2020 ERCOT Long-Term System Assessment* with units that were retiring but had no official announcement or had recent developments that might delay retirement until after 2030 (ERCOT, 2020a). The high retirements represent a scenario where only 310 MW of coal remains in ERCOT in 2030 because of economic pressures from increased renewable deployment and environmental, social, and governance pressures from capital markets and regulatory entities.

The low-renewables scenario is unlikely: it is unlikely that transmission upgrades in West Texas would coincide with significantly reduced renewable development and delayed coal retirements. If surplus transmission was available, renewable energy developers would almost certainly continue building projects in West Texas. However, the intent of the low-renewables scenario is to assess how the value of the transmission upgrades would change in a worst-case scenario—such as if growth in renewables diminishes significantly and old thermal power plants remain online, which causes production cost savings from expanding transmission from west to east to significantly diminish. Modeling this worst-case scenarios is consistent with approaching future uncertainty using a least-regrets approach.

Stochastic Variables—Gas and Load

Gas and load were used as probabilistic variables that were randomly sampled for each model simulation due to the inherently volatile nature of gas prices and the uncertainty around electrification and load forecasts. These factors are applicable across all regions in the United States and are two key drivers in production costs and resource adequacy needs. The practice of adopting only a few long-term scenarios and potentially leaving out extreme combinations of gas and load values means that volatility and varying economic conditions are not addressed adequately during planning. The approach used here presents a methodology for assessing the expected value across more than 120 different futures using the three resource mixes and 40 probabilistic gas and load levels. A scenarios-based approach that also uses probabilistic methods for randomizing the selection of key variables (like load and gas prices for this study) more effectively captures volatility and varying economic conditions.

Gas Multiplier Distribution

U.S. natural gas prices have been historically low since the shale revolution of the 2010s, and many planning studies consistently predict that this trend will continue. However, relying on the continuance of the trend can leave the grid exposed to price volatility and supply pressures in real time, with the transmission projects necessary to access alternative or zero-fuel-cost resources not having been undertaken.

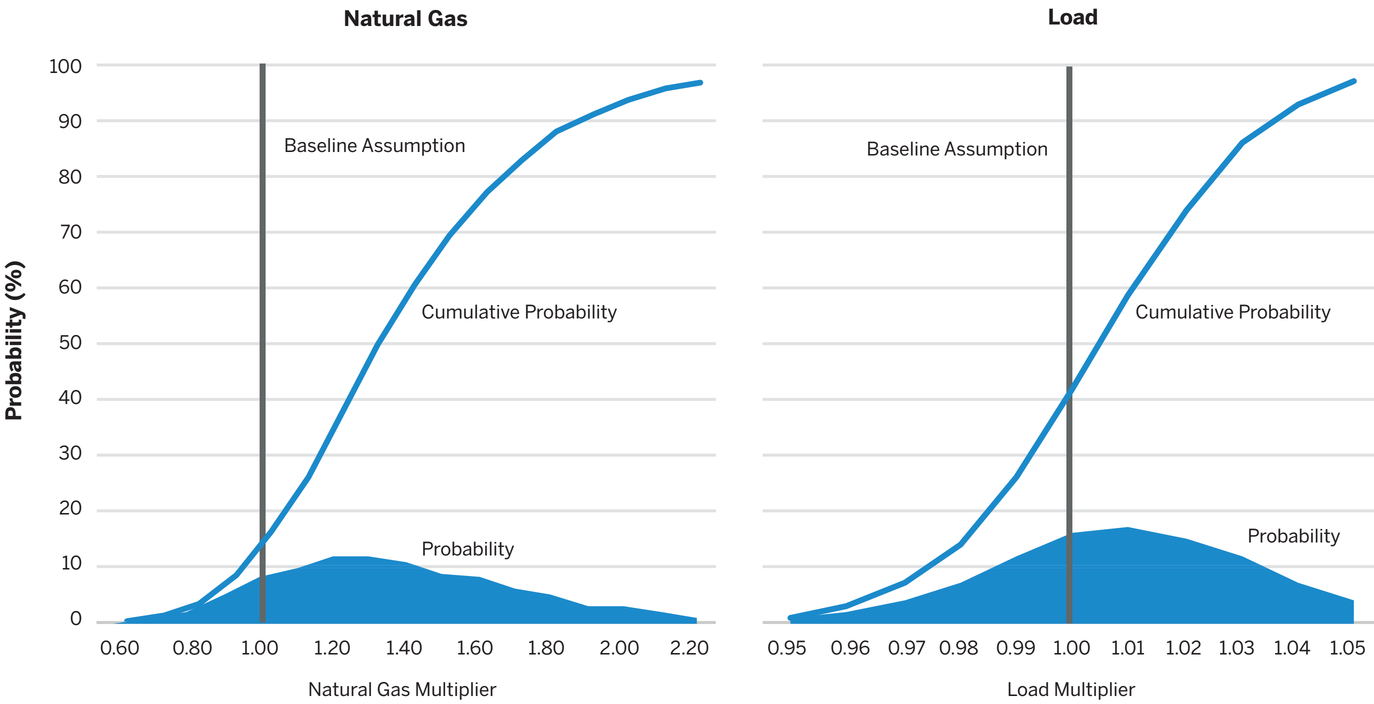
To assess how the value of the West Texas Export transmission upgrades changes under different natural gas price scenarios, a set of multipliers was developed and each was assigned a probability of occurrence (see Figure 16, p. 35). PLEXOS samples this distribution and applies the price multiplier to the monthly gas forecast, creating a study period with lower or higher gas prices. For additional granularity in modeling volatility, intra-year, -month, or -day price volatility could be sampled. The methodology outlined in this section would allow a planner to model any level of volatility. The key point here is not the actual multiplier values or the exact probability distribution, but rather to encourage planners to test a large sample size of future scenarios for a robust understanding of how a project's benefits vary given uncertainty in forecasting the future.

The range of multipliers was chosen to achieve a real 2018-dollar range of minimum and maximum gas prices of $1.50 to $8.50. The minimum price reflects historical minimum monthly Henry Hub spot prices in real terms (EIA, 2022). The maximum price, which has the lowest probability weight, is meant to showcase a world in which supply-side restrictions push prices upwards either due to environmental, social, and governance concerns or the declining availability of cheap natural gas resources. While this range may seem large, and seem to counter fundamental gas price outlooks, given that Henry Hub gas prices rose from $3.00 to $7.82 between May 2021 and April 2022, it is not unreasonable.

The probability distribution is lognormal and skewed to the higher multipliers based on a technical minimum price of future natural gas resources and the growing global sentiment toward reducing fossil fuel consumption and limiting continued exploration of new resources.

FIGURE 16

Range of Stochastic Samples for Natural Gas and Load Uncertainty



Probability distributions of natural gas prices and load multipliers. The probability curve (shaded region) shows the probability of any one point occurring, while the cumulative probability shows the likelihood that a value is lower than a given point.

Source: Energy Systems Integration Group.

Load Multiplier Distribution

Load growth forecast uncertainty is another key factor in understanding the value of a large-scale transmission project under future conditions. This study kept load forecast uncertainty straightforward by providing a lognormal distribution of ±5 percent load relative to the baseline assumptions. The probability distribution is skewed toward the higher load-growth scenarios because of the greater likelihood of increased load due to electrification as climate change goals are met. Lower load-growth scenarios represent a lagging electrification trend or sluggish economic growth.

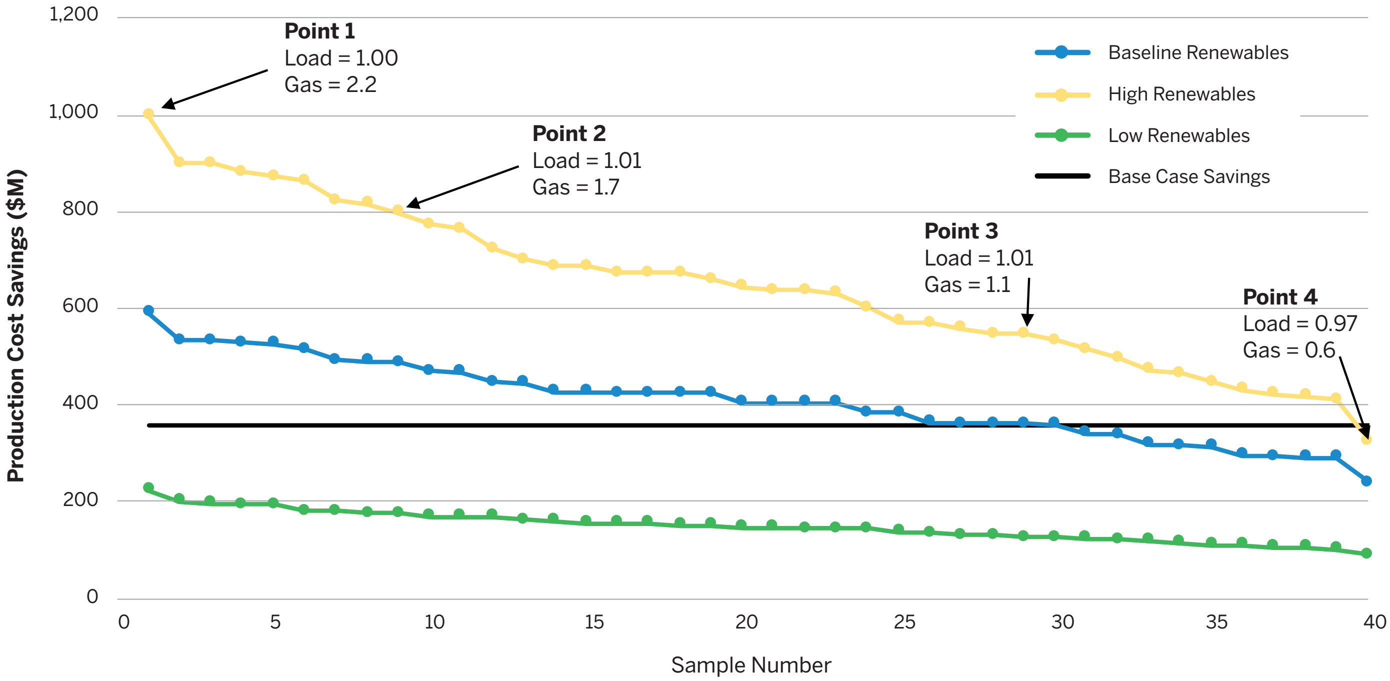
As with the natural gas distribution, the load growth values used in this study are meant to demonstrate the use of a probabilistic methodology for developing a range of future uncertainties. Individual grid planners will have data related to their local load forecast uncertainties and can develop probabilistic distributions of load growth scenarios so that an expected value of the transmission project under a range of futures can be determined.

Risk Mitigation Results

The risk mitigation benefits—avoiding costly outcomes to unlikely but possible high gas prices and high-load situations—were assessed using the base case transmission scenario and upgrade Option 1, using the single 2013 weather year renewable generation, 2030 P50 load (ERCOT's median load forecast), and the 2030 resource additions and retirements. Figure 17 shows the range of production cost savings that upgrade Option 1 provided by sample number and renewables/retirements scenario. (For brevity, the chart for Option 2 risk mitigation results is not shown; the trends shown in Figure 17 for Option 1 are consistent with Option 2, with slightly different production cost savings levels due to the greater benefit of the HVDC line in reducing gas usage in Houston under high gas price cases.) The samples were ordered from highest production cost savings to lowest (sample 1 to sample 40 in the figure) for each of the

FIGURE 17

Risk Mitigation Benefits Across a Range of 120 Stochastic Samples, Upgrade Option 1, 2030



Production cost savings are shown across a range of 120 different combinations of renewable deployment, retirements, gas price, and load levels. The avoided costs from high prices significantly outweigh the downside costs if the transmission is less economic in a low-renewables environment.

Source: Energy Systems Integration Group.

scenarios (baseline, high, and low). For reference, call-outs in the figure show the combination of load and gas multipliers for specific sample numbers.

The results shown in Figure 17 highlight two core principles of taking a multi-value planning approach. One is that the benefits of a large-scale transmission project are directly related to the distribution and magnitude of the resource mix and the magnitude of the fuel prices of resources that are being connected by the transmission line. In this case, the West Texas Export upgrades allow a greater amount of zero-marginal-cost resources to serve load, which shields the grid from exposure to high production costs in the high gas price samples. The small variation in savings from the low-renewables scenario is consistent with the fact that a significant number of coal units remain online, which both insulates the grid from high gas prices and means that installed renewable capacity is significantly reduced. This contributes to the transmission having less of a benefit for alleviating congestion on the West Texas Export constraint, as the transmission upgrade is no longer bringing as much energy across the export interface.

Sensitivities bounding the baseline projections provide a range of benefits that can inform a least-regrets approach to planning. A least-regrets approach ensures that a portfolio of projects, in this case, transmission upgrades, will perform well (benefits outweighing the costs) across many possible futures. This approach would identify scenarios where the project does not produce positive net benefits (low-renewables case) and where the missed benefits are significant because the upgrade was not undertaken (baseline and high renewables where gas prices are significantly higher than forecasted). Under the low-renewables and low-retirements conditions, the transmission upgrade underperforms and loses 37 to 75 percent of its production cost savings relative to the base case (these are the worst-case conditions where benefits of the transmission upgrade do not outweigh the costs). In contrast, under the high-renewables and high thermal-retirements condition, the upgrade is 15 to 180 percent more valuable relative to the base case savings (these are the maximum benefit conditions).

To synthesize the results for all 120 samples, this study considered the range in potential outcomes from the risk mitigation scenarios, comparing the worst case (where the transmission is 75 percent less valuable than the base case) against the best case (where the transmission is 180 percent more valuable than the base case). As a result, in Option 1 the transmission benefits are reduced by $276 million in the worst-case result and increased by $667 million in the best-case result. To convert this into a single expected benefit value, we used the range of $391 million ($667 million minus $276 million). This range creates a single benefit value to compare against the other benefits evaluated in this study.

Key Takeaways

The risk mitigation analysis demonstrates that the expected value of a transmission project is highly dependent on the conditions modeled during the planning process. By taking a stochastic approach to account for uncertainty and volatility in key drivers like projected resource mix, fuel prices, and load growth, a wide range of potential benefits can be assessed. The parameters tested in this analysis are by no means exhaustive. To provide a clear understanding of the expected value of a project, probabilities must be assigned to different scenarios and stochastic variables according to the situation and needs of a given system. Moving away from a snapshot analytical framework to assessing multiple future scenarios is vital for effective planning.

Furthermore, the risk mitigation analysis highlights the asymmetry of potential costs to ratepayers. The additional cost of building the transmission line is a known, fixed amount, whereas the risks of not having the transmission are uncertain and skewed to the high end—for example, not having transmission developed, and thus significant amounts of zero-fuel-cost resources cannot serve load due to congestion, means more expensive units must run. In other words, there is a vastly greater potential for negative effects of high gas prices, high load, or high congestion from additional renewables and retirements in a system *without* the West Texas Export transmission upgrade, than there is for the transmission upgrades not to provide as much benefit to the system (shown in the low-renewables and low-retirements case). Large-scale transmission is a flexible investment which, given uncertain futures, prevents it from becoming a stranded asset and, conversely, allows it to provide greater value than initial planning expected.

Resource Adequacy Benefits

Transmission as a Capacity Resource

Much of the analysis thus far has focused on the energy benefits of new transmission. These benefits are attributed to decreased congestion (allowing lower-cost resources in one region to displace higher-cost resources in others), reduced curtailment, or access to lower-cost renewable energy. However, planning a future energy mix is only one facet of system planning. Equally, and perhaps more importantly, the system's capacity needs and associated costs must be considered.

According to FERC, "transmission investments, even those not made to satisfy a reliability need, generally enhance the reliability of the transmission system by increasing transfer capability, which, in turn, reduces the likelihood that a public utility transmission provider will be unable to serve its load due to a shortage of generation over a given period. This enhancement in reliability can be measured as a reduction in loss of load probability, or the likelihood of system demand exceeding generation over a given period" (FERC, 2022, p. 165).

Specifically, the reduction in loss of load probability (LOLP) is represented by the amount of firm capacity needed on the system to meet the resource adequacy reliability criteria (e.g., a 1-day-in-10-year loss of load expectation (LOLE)). While transmission itself does not add capacity (MW) to the system, it facilitates the transfer of power between regions, accesses available capacity to improve system reliability, and is a foundational element of resource adequacy analysis. In this study of the Texas grid, the transmission can move surplus capacity to one region and help mitigate the probability of loss-of-load events (LOLEv) in another. This resource adequacy benefit can therefore reduce the need for local capacity, and defer or eliminate the need for new gas turbines or enable uneconomic generation resources to retire.

The resource adequacy benefits from large-scale transmission depend on the type of underlying system risk. In some systems, resource adequacy shortfalls are highly location-dependent, where there is not enough local capacity to serve load and the location is dependent on transmission flows for reliability. Transmission serving this need has a resource adequacy benefit. In other cases, however, shortfall events occur because there is not enough available capacity anywhere on the system, regardless of location. It should come as no surprise that transmission additions used to access more renewables in a specific region will not help to avoid this type of shortfall. Transmission additions would only decrease congestion during times when renewable output, and thus supply, is in abundance and there is no risk of shortfalls on the system.

In the West Texas Export upgrade Option 1, additional renewables are being sited in a region that already has extensive wind and solar build-out. As a result, siting additional wind and solar in the West Texas region increases the overall geographical correlation of the wind and solar resources, and there are few, if any, times where transmission constraints would occur during a time of system-wide shortfalls.

The situation in Option 2, in contrast, does stand to see a benefit from large-scale transmission from a renewables-rich area. Houston is a load pocket due to high load and limited transmission interchange with other ERCOT regions. During scarcity events, it is possible that there is insufficient capacity in the load pocket and that the capacity shortfall cannot be resolved by existing transmission, not because the resources are not available but because of transmission limitations into the region. In this case, an additional transmission line (as proposed in the West Texas Export upgrade Option 2) could deliver energy during times that would have otherwise experienced scarcity and loss of load. While both West Texas Export upgrades have a similar effect on the total transfer capability across the interface, Option 2 could have more pronounced capacity benefits if it is able to deliver energy directly to a load pocket during times of shortfall. This would not only enable a valuable transfer of energy but serve as a local capacity resource as well. Our modeling examined this possibility.

A Probabilistic Approach to Quantify Resource Adequacy Benefits

To evaluate the resource adequacy benefits of investment in and expansion of the underlying transmission network,

TABLE 11

Illustrative Matrix of Loss-of-Load Events by Weather Year and Outage Draw

Outage Draw	Weather Year:	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total
Outage Draw	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	2	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
	3	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	3	2	0	0	0	0	0	0	0	8
	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	3
	5	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	1	0	0	0	0	0	0	0	6
	...																																									
	N	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	1	0	0	0	0	0	0	0	5
Total		0	0	0	3	1	0	0	1	0	0	5	0	0	0	0	0	0	1	0	0	3	0	0	3	0	3	0	0	0	0	0	12	9	0	0	0	0	0	0	0	40

An illustration of the probabilistic resource adequacy simulation matrix, which shows 40 weather years (columns) each evaluated across 10 outage draws (rows) for a total of 400 simulations.

Source: Energy Systems Integration Group.

the study conducted a resource adequacy assessment to calculate the expected unserved energy (EUE) and LOLE of the ERCOT system, including the current interface transmission limits and resource mixes for each study year. All three transmission scenarios, base case, Option 1 (4 AC lines), and Option 2 (3 AC lines + 1 HVDC line) were assessed using the probabilistic methodology outlined in this section.

In this analysis, the transmission limits are modeled as hard constraints, and the system will shed load instead of violating the limit. The modeling utilized a sequential Monte Carlo simulation approach, where the 8,760-hours-per-year, chronological production cost simulations were performed across 400 samples. The sampling was conducted across 40 weather years, each of which was evaluated across 10 unique, randomly drawn forced outage profiles for the thermal fleet. An illustration of this sample matrix is provided in Table 11.

As a result, the grid was simulated across 3.5 million hours of operation (400 samples x 8,760 hours per year, per sample), and the unserved energy events were tabulated across the 400 samples. The weather years assumed hourly fluctuations in ERCOT's demand based on historical ambient weather conditions,[9] and a unique 8,760 hour wind and solar generating profile was developed for each weather year, across each generating plant (UL Services Group, 2021). Figure 18 (p. 40) shows the fluctuation in annual peak demand (top) and the top 200 hours of demand by weather year (bottom), showing that peak loads fluctuate ±5 percent relative to the P50 expected load forecast published by ERCOT. Figure 19 (p. 41) illustrates the monthly total ERCOT wind and solar capacity factor (as a percentage of the total installed capacity) across the 40 years of historical weather, where the box plot shows the range of potential variable renewable energy fluctuations, both seasonally and within each month.

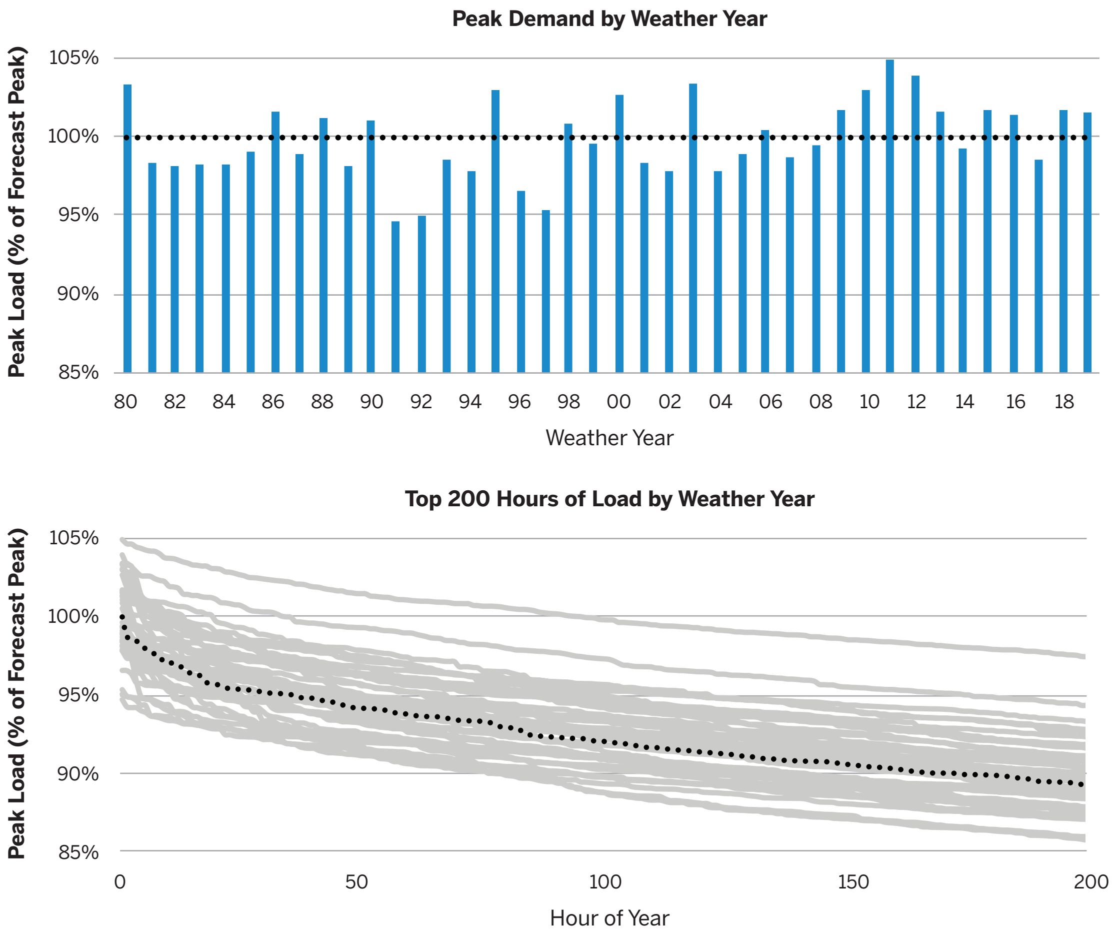
Translating Reliability Benefits into Cost Savings

Resource adequacy analysis measures the likelihood of a shortfall event occurring using the multi-weather year and outage sampling discussed in the previous section. It does not, by itself, ascribe a monetary value to changes in reliability. To bridge this gap, this study compared the reliability improvements of Option 1 and Option 2, new large-scale transmission upgrades, to a capacity resource that would typically be added to a system to improve reliability—either a new combustion turbine or a battery energy storage system. This allows the reliability benefits

9 Data provided by ERCOT planning and aligns with the ERCOT Long-Term Load Forecast Report, https://www.ercot.com/gridinfo/load/forecast.

FIGURE 18

Peak Demand and Top 200 Hours of Load, Relative to the P50 Forecast



The left chart shows the annual peak demand for each weather year relative to the long-term average, with fluctuations between +/–5 percent. The right chart shows the top 200 hours per year of system load, sorted from highest to lowest for each weather year.

Source: Energy Systems Integration Group. Data: Electric Reliability Council of Texas and UL Services Group.

of transmission to be quantified relative to the amount of deferred capacity from a generation or storage resource. We used Potomac Economics' estimate of the ERCOT net cost of new entry (net CONE) of a combustion turbine, or the $/kW-year cost of new gas capacity, minus potential revenues in the energy and ancillary service market. According to the *2020 ERCOT State of the Market Report*, the net CONE value is approximately 60 $/kW-year for a new combustion turbine (Potomac Economics, 2021).

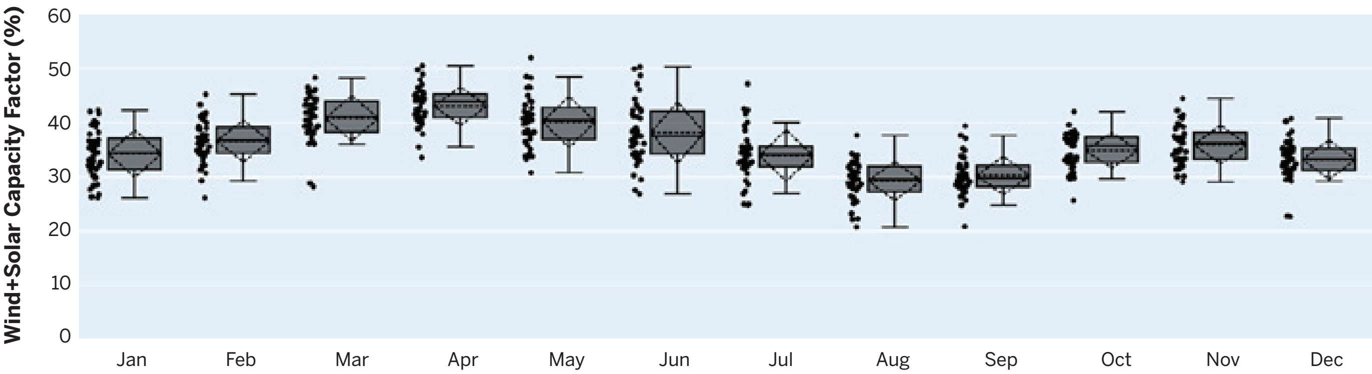
For example, if an increase in transmission capability reduces the LOLE of the system by an equivalent capacity addition of 1,000 MW of gas, this would translate to an annualized resource adequacy (deferred capacity) benefit of $60 million.

Simulations of the Resource Adequacy Benefits of the West Texas Export Upgrades

We quantified the loss-of-load metrics across three cases: the base case results without any new transmission upgrades, the Option 1 AC-only upgrade, and the Option 2 upgrade case that includes the addition of an HVDC transmission line to Houston. The results showed that, in all cases, LOLE is at or near 0.35 days per year.[10] Results of the resource adequacy simulations are provided in Table 12 including LOLEv, loss of

FIGURE 19

Range of Monthly Wind and Solar Capacity Factors Across 40 Weather Years



The monthly distribution of capacity factors for wind and solar units in Texas from 1980 to 2019 are shown. Both within and between months, output from wind or solar units can fluctuate by years.

Source: Energy Systems Integration Group. Data: Electric Reliability Council of Texas and UL Services Group.

load hours (LOLH), LOLP, EUE, EUE/LOLE, and LOLH/LOLE.

The results indicate no noticeable resource adequacy benefit to relieving the West Texas Export constraint. Intuitively this makes sense—the interface between West Texas and the rest of ERCOT is only limited during periods of high wind and solar generation. During these periods, the system has a large amount of capacity available and is thus not in a shortfall. By 2030, the vast majority of loss-of-load events were observed to occur during periods of low wind and solar availability, and as a result the extra transfer capability available on the West Texas Export constraint does not yield additional benefits because the base case export transfer limit was not reached. This means that available transmission export capability is not the limiting factor causing loss-of-load events to occur.

While a lack of resource adequacy benefit makes sense for the Option 1 transmission upgrades (AC-only transmission additions between West and North Texas) because of potential issues with the Houston Import constraint, it was expected that a direct tie to the Houston load pocket (Option 2) would provide additional resource adequacy benefits. However, results for Option 2 indicated that when load-shedding events are occurring in Houston, the entire ERCOT system is deficient, including renewables-heavy West Texas. In other words, during shortfall hours, where load shedding occurs, there is no surplus capacity available in ERCOT, regardless of transmission constraints. This is indicative

TABLE 12

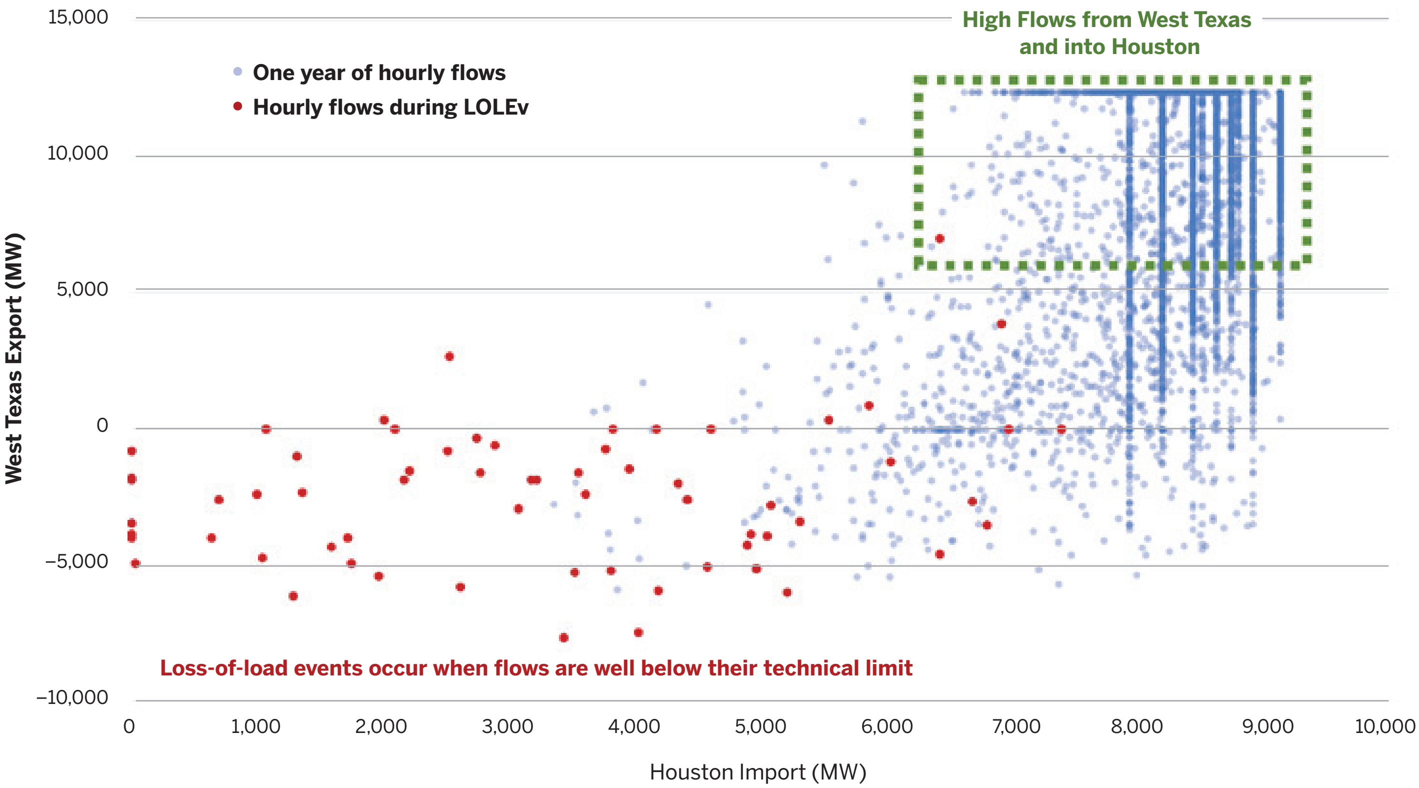
2030 ERCOT Loss-of-Load Metrics Across Three Transmission Configurations

	LOLE (Days/yr)	LOLEv (Events/yr)	LOLH (Hours/yr)	LOLP (% of days)	EUE (GWh/yr)	EUE/LOLE (MWh/event)	LOLH/LOLE (Hours/event)
Base case	0.35	0.40	1.75	0.01%	5.2	13,074	4.4
Option 1 transmission	0.36	0.42	1.77	0.01%	5.4	12,722	4.2
Option 2 transmission	0.35	0.40	1.73	0.01%	5.1	12,906	4.4

Source: Energy Systems Integration Group.

10 Note that the base case reliability level was intentionally below 0.1 days per year, a common criterion used across North America. This is because ERCOT does not have a capacity market or established reliability criteria. Recent ERCOT reports suggest an economic market equilibrium reserve margin of 0.49 days per year, and the study intended to show reliability benefits by adding new transmission.

FIGURE 20
Line Flows on the West Texas and Houston Interfaces During Loss-of-Load Events



The chart maps the flow of electricity over the West Texas Export interface and the Houston Import interface for the resource adequacy results of Option 2. The red dots show hours where loss-of-load events are occurring in ERCOT, which correlates with no exports from West Texas to the east—meaning that loss of load is not being caused by transmission constraints, but rather capacity shortfalls.

Source: Energy Systems Integration Group.

of a system-wide capacity need rather than a locational capacity need. Therefore, the transmission upgrade bringing renewable resources from West Texas to East Texas (two relatively close geographical areas) provides negligible resource adequacy benefits under the assumptions evaluated. The future 2030 ERCOT system is facing capacity shortfalls that are not due to transmission constraints. When shortfall events occur, there is not surplus capacity anywhere in ERCOT.

This result shows that to realize resource adequacy benefits from transmission projects, one may have to look to large-scale interregional transmission projects where sufficient additional capacity may be available to resolve shortfall events.

Figure 20 shows a scatter plot of transmission line flows with West Texas exports on the y-axis and Houston imports on the x-axis. The blue dots represent hourly flows across an entire year of operation (8,760 observations), and the red dots show line flows during loss-of-load events across the 400 probabilistic samples. This figure illustrates the periods of loss of load all occurring at times of low Houston imports (due to lack of surplus capacity in the rest of the state) and periods of reverse flow on the West Texas Export interface from load centers to West Texas (due to low wind and solar availability in West Texas).

Key Takeaways

As noted above, the results of this analysis are specific to the ERCOT system and not necessarily the case for other regions. Much of the value of the resource adequacy analysis is in the methodology, which can be applied to any system. For example, the New York City zone (NYISO Zone J), the eastern areas of PJM, and other notable load pockets in the country are both capacity- and transmission-constrained; therefore, increased transmission could yield significant transmission benefits. Another reason that this finding is specific to the West Texas application is because additional renewables are being sited in a region that already has extensive wind and solar build-out, and the system already has 39 percent variable renewable generation per year in 2023. As a result, the addition of wind and solar in the West Texas region by 2030 increases the overall geographical correlation of the wind and solar resources, and there are few, if any, periods when transmission constraints would occur during a time of system-wide shortfalls.

It is also important to note that just because the weather events and forced outage draws evaluated across the 400 random samples in this analysis did not show a capacity benefit to the West Texas Export transmission upgrades, there are conditions where additional transmission *would* yield reliability and resource adequacy benefits, for example, periods where cloud cover or low wind speeds in coastal Texas occur during periods of high output in West Texas. If this were to occur at the same time as forced outage events, there could be capacity benefits for transmission. In addition, more fossil plant retirements in the Houston area, or higher-than-expected load growth in West Texas than what was assumed in this study, would increase transmission's resource adequacy benefits.

Resilience Benefits

Concern over the existing grid's resilience is growing, as fears surrounding the uncertainty of increasingly severe weather events occurring with greater frequency due to climate change are mounting at local and federal levels. A resilient grid is one that can withstand severe events with reduced stress and load shedding or avoid catastrophic failures due to unforeseen generation outages, collapsed transmission lines, fuel supply disruptions, or rapid ramping in load (GAO, 2021; Goggin, 2021). Whereas resource adequacy benefits reduce the number of shortfalls, resilience benefits are reductions in the magnitude of the loss-of-load events that remain.

To quantify resilience, this study did not explicitly model discrete severe weather events or outage events; rather, it evaluated grid operations using the same methodology from the resource adequacy analysis by modeling 40 historical weather years of load and renewable generation with randomized generator outage sampling. In the resilience analysis, we went one step further and assessed the severity of the events themselves, and looked at how levels of unserved energy and duration of the specific events changed with and without the transmission upgrades.

The benefit of this approach is that these data are readily available as output from resource adequacy analyses done across the industry, meaning that applying this methodology requires less data preparation and fewer modeling simulations. The limitations of this approach are that the extreme load and generator or transmission outage conditions exhibited during specific severe weather events (like Winter Storm Uri) are not explicitly modeled. However, creating specific extreme weather scenarios to test portfolios of planned transmission and generation is an important part of creating a resilient grid for the future. Individual planning entities or ISOs/RTOs should rely on lessons learned from historical events and incorporate consideration of similar events occurring and how the grid responds to those events under future system conditions.

Methodology

While this study did not specifically embed extreme events into its model, it offers an approach to quantify these benefits for any type of model scenario. The methodology focuses on identifying the reduced magnitude and duration of load-shedding events on the system before and after transmission upgrades are made.

In the West Texas example, the focus was on resilience benefits in 2030. The 400 simulations ran each scenario (base case, Option 1, Option 2) for the resource adequacy analysis, and they were reviewed to locate loss-of-load events that occurred at the same time in the base case and the two cases with new transmission. For example, if a loss-of-load event occurred on January 11 in a base case sample and also occurred on January 11 in Option 1, the difference in unserved energy for the event in the Option 1 scenario was considered the resilience benefit. Since the base case and Options 1 and 2 with upgraded transmission are all modeling the same events, we can compare the effect of the transmission lines on the magnitude of unserved energy in each loss-of-load event. The resilience benefits are quantified by valuing the reduction in the magnitude of remaining loss-of-load events using the value of lost load and unserved energy of the events.

Results

For the two West Texas Export upgrades, the study showed no resilience benefit for upgrade Option 1 (4 AC lines). Upgrade Option 2 (3 AC lines + 1 HVDC line) provided some resilience benefit by reducing the magnitude of total unserved energy compared to the base case system across the 400 samples. Table 13 summarizes the resilience results for Option 2 relative to the base case.

Key Takeaways

The ability of transmission to reduce the severity of events where shedding load is required to maintain grid operations is a significant benefit. The value of lost load across many different grid operators and utilities ranges from $5,000 to $50,000 depending on location, which means that even mitigating a small fraction of load shedding provides significant economic benefits.

However, the most important benefit of increased resilience is the reduction in adverse conditions to which customers are exposed during extreme events. Grids are not designed to have no loss-of-load events, but it is critical that when those events do occur, their impact on (and costs incurred by) the people and businesses the grid serves are as minimal as possible. Transmission can provide significant resilience benefits, but in the West Texas example, increasing access to renewable energy zones does not necessarily increase resilience if the load-shedding events occur when renewable generation is low. The limited resilience benefit from transmission found in analysis of the West Texas examples (both Option 1 and Option 2) was a key reason for assessing the resilience benefits of transmission between regions with different weather and load patterns, allowing grids to benefit from diverse load and resource mixes to lessen the impact of load shedding on each system during emergencies.

Further development of methods to model and quantify resilience benefits due to transmission are needed. This is a crucial research and development need for the industry. The analysis performed here is useful for quantifying resilience benefits built on resource adequacy analysis; however, this analysis does not account for correlated grid disruptions like those experienced in Winter Storm Uri in February 2021. Our methodology implicitly considers the random outage rates of generators and correlated weather risks for renewables and load. In addition, future work should incorporate discrete events to stress test the system through different outage types (such as transmission outages), sustained low wind and solar output, and common mode fuel supply disruptions in many different combinations. Quantifying the benefits of grid resilience under these conditions should focus on how the grid structure alleviates burdensome load shedding in both magnitude and duration for the consumer.

TABLE 13

Avoided Unserved Energy and Resilience Value in ERCOT with Option 2

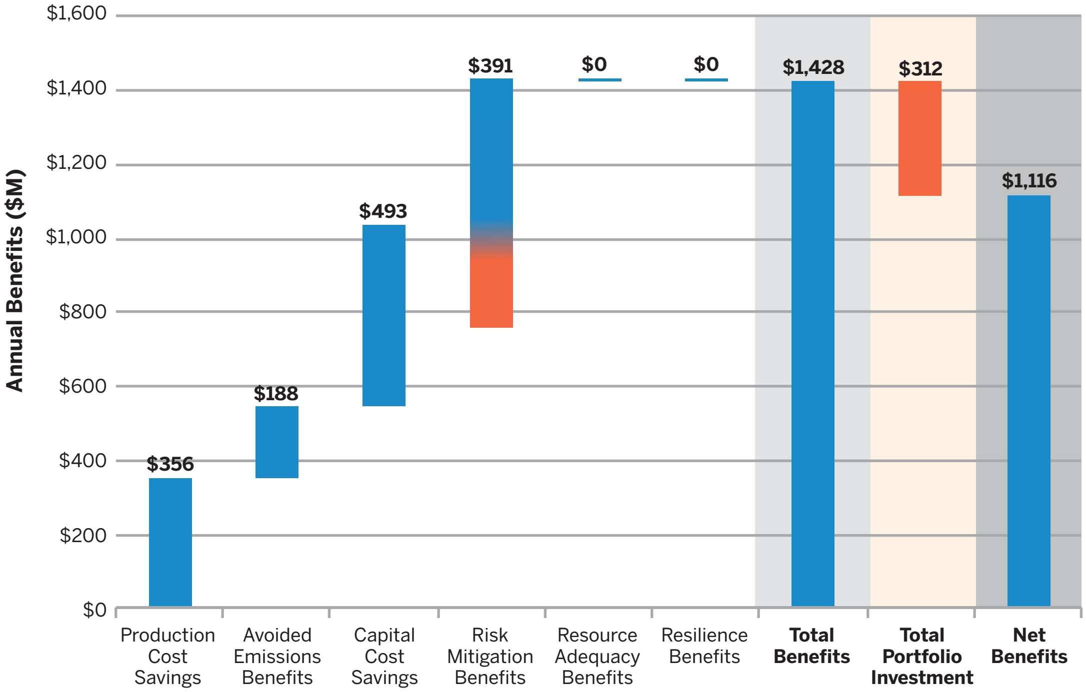
System Component	Avoided Unserved Energy	Total Resilience Value	Average Resilience Value per Event	Annualized Resilience Value
Option 2 transmission (3 AC + 1 HVDC)	42,901 MWh	$858 million	$8.5 million	$2.1 million

The West Texas Option 2 provides some resilience benefit by reducing the magnitude of unserved energy during some loss-of-load events relative to the base case.

Source: Energy Systems Integration Group.

FIGURE 21

Multi-Value Benefit Stacking for the Transmission Line Relieving the West Texas Export Constraint, Option 1



The six bars on the left represent benefits that are added together to arrive at the total benefits of $1.428 billion. After investments are subtracted (red bar), the net annual benefits of the transmission line are calculated to be $1.116 billion.

Source: Energy Systems Integration Group.

Multi-Value Benefits Stack

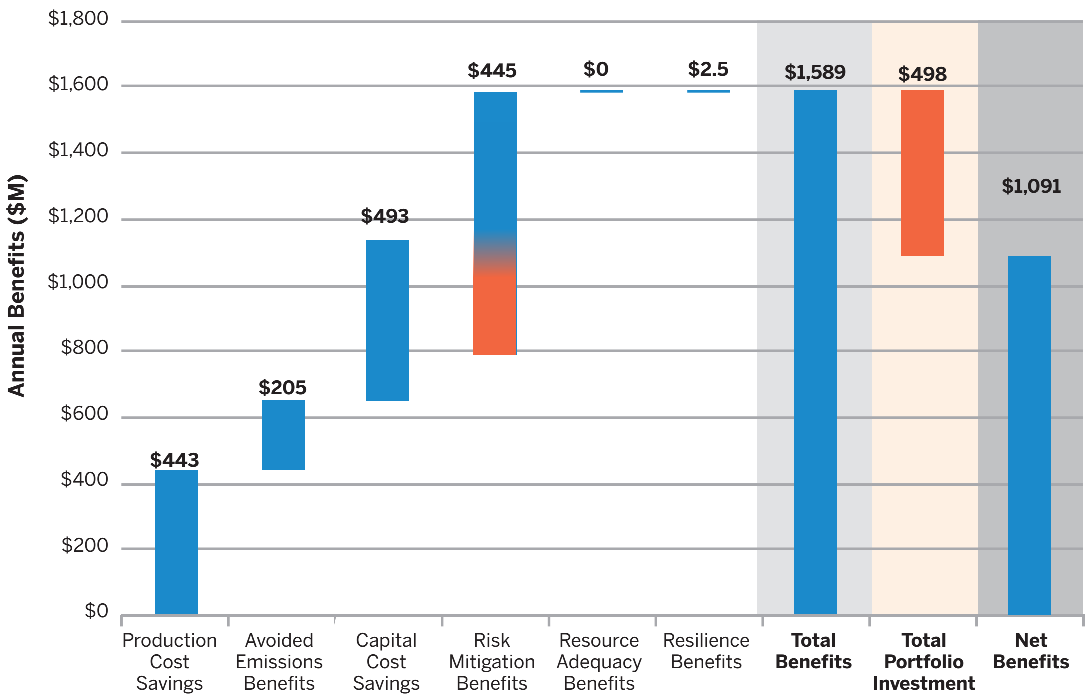
The previous sections illustrate and quantify the multiple benefits that large-scale upgrades to the West Texas Export transmission interface may provide, including production cost savings, avoided emissions, generation capital cost savings, risk mitigation, resource adequacy, and resilience. These categories of benefits are important individually, but the real-world impact of large-scale transmission upgrades can only be seen by quantifying these benefits' collective effects—through using a multi-value framework.

When implemented in this study, the multi-value framework clearly shows that transmission upgrades are a valuable, economically important solution to the West Texas Export constraint. Figures 21 and 22 (p. 46) show the value stacking of the six benefits discussed in this report for the year 2030 for transmission upgrade Options 1 and 2. These multi-value benefit stacks show the portion of the benefits (blue bars) coming from the six categories evaluated in the project, where the height of each segment demonstrates the relative value each benefit brings to the line. Each segment stacks up to the total benefits, which can be compared against the necessary capital investment cost (orange bar) to calculate the net benefits (blue bar on the far right). This benefit-cost framework allows transmission planners to make key decisions on whether to invest in new transmission projects and to compare different projects against one another.

Note that the risk mitigation bar has both benefits (blue) and potential costs (orange) that could arise if future conditions are not as favorable for new transmission as the baseline assumptions. As a result,

FIGURE 22

Multi-Value Benefit Stacking for the Transmission Line Relieving the West Texas Export, Option 2



Results from stacking the multi-value benefits for Option 2 in 2030 show total benefits are $1.59 billion compared to $443 million when considering production cost savings only.

Source: Energy Systems Integration Group.

the risk mitigation shows a range of potential benefits that could arise across different assumptions.

While production costs alone may not justify transmission upgrades (benefit-cost ratio of 1.1 for Option 1 and 0.89 for Option 2), even a subset of the multi-benefit stack justifies the upgrades (total benefit-cost ratio of 4.57 for Option 1 and 3.19 for Option 2).

It is important to note that this study only quantified six primary benefits, shown in Table 2 on p. 19. Additional benefits are certain to exist, but either are difficult to quantify or the study team did not have enough information available to do so. One example is benefits associated with avoiding the replacement of existing aging transmission lines, which was not quantified here due to a lack of information on the existing transmission network's needs. Another example is storm hardening. One could quantify the benefits associated with less damage to the new 345 kV infrastructure in the West Texas Export interface (in Options 1 and 2) during storms. In addition, grid stability in relatively weak regions of the grid is likely improved with additional transmission interconnections—potentially avoiding disruptions immediately following a contingency event. The quantification of these benefits will allow us to represent the benefits of large-scale expansion of the transmission network even more precisely.

ERCOT to Southern Company Transmission Benefits

As a core principle, multi-value planning extends beyond relying solely on production cost savings to quantify the value of new large-scale transmission projects, taking into account a more complete range of benefits from these projects. Different types of transmission expansion show different benefits. For instance, some transmission projects have mainly energy benefits, as they connect load centers to areas rich in renewables, while other transmission projects provide capacity benefits by accessing a region with more diversified resources. A multi-value framework identifies where the benefits exist for each type.

In the analysis of ERCOT in the previous section, we quantified the benefits of large-scale transmission to connect remote renewables to a distant but largely homogeneous load. That part of the study found significant benefits in four categories (production costs, emissions reductions, generation capital cost savings, and risk mitigation), small benefits for resilience, and no benefit for resource adequacy. These last two areas of low benefits were expected, as the West Texas region already contains the majority of the state's wind and solar resources, and additional renewable build-out would be correlated with existing output—providing little additional supply during periods with low wind and solar generation.

Where resource adequacy and resilience benefits stand out, however, is in connecting systems with loosely correlated net load behavior. The resource-sharing made possible through interregional transmission connecting regions with different weather patterns and different resource mixes increases load diversity, the geographical diversity of renewables, and the number of available generators during an emergency event. The more electrically diverse the system footprint, the less likely weather events will increase load and decrease renewable output at the same time.

To quantify this benefit, we assessed an interregional transmission project by connecting the ERCOT North footprint to Southern Company's southeastern utilities' footprint (including Mississippi, Alabama, and Georgia) (Figure 23, p. 48). This line was chosen because it connects large areas with substantially different geographical exposure, diversity of load, and diversity of generation. The southeastern United States has limited viable wind energy potential and is confined to solar build-out. A new transmission line to ERCOT would allow southeastern utilities to contract for lower-cost wind resources in Texas. Additionally, transmission projects between ERCOT and Southern Company appear on a recently published list of "shovel ready" projects which could be built in the near future (Goggin, Gramlich, and Skelly, 2021).

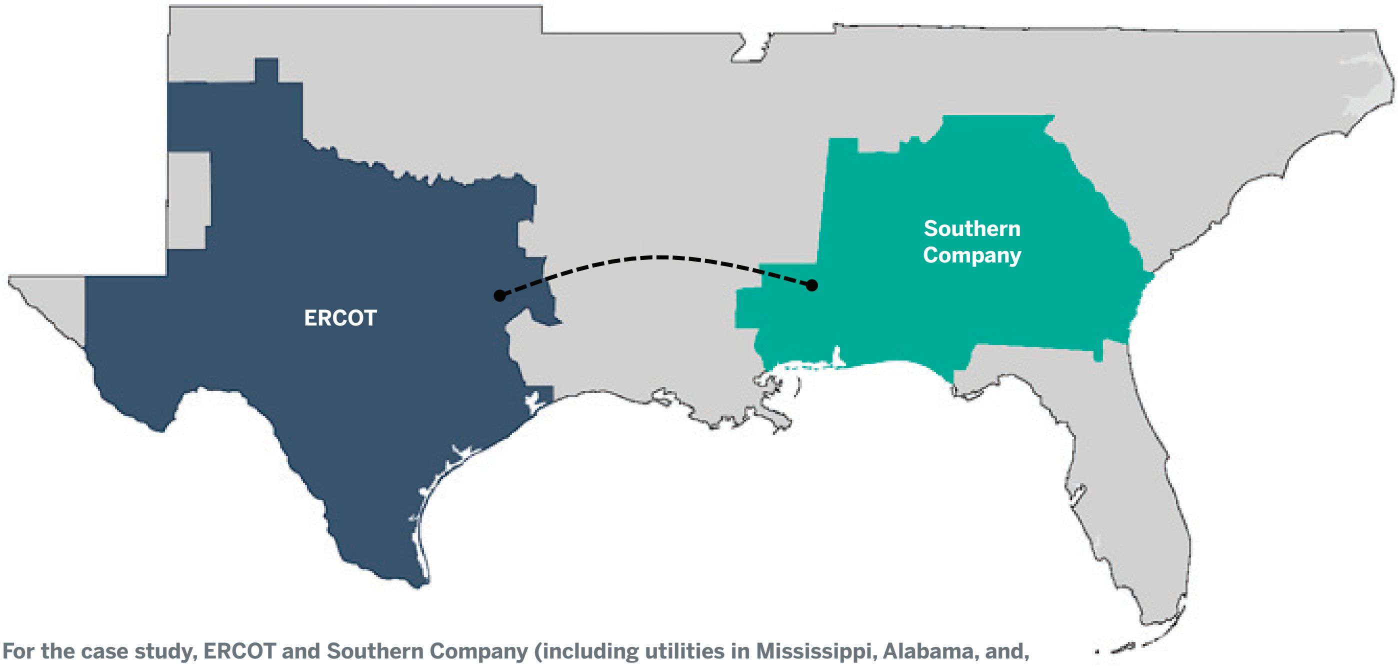
The methodology described here is intended to act as a point of reference for assessing how to value the resource adequacy benefits of transmission when that benefit positively impacts one or both interconnected regions' LOLE. The same resource adequacy analysis methodology used in the previous section is used here, with an added benefit valuation component. Consideration of production cost, emissions, and resilience transmission benefits is also included.

Modeling Southern Company

The 2030 ERCOT base case outlined throughout the first sections of this study was used, but expanded with the addition of the Southern Company power system.

FIGURE 23

Potential Interregional Transmission Link Between the Southeast and Texas



For the case study, ERCOT and Southern Company (including utilities in Mississippi, Alabama, and, Georgia) are connected via a 2 GW HVDC transmission line.

Source: Energy Systems Integration Group.

Southern Company's footprint in Mississippi, Alabama, and Georgia was modeled as a single zone with a resource mix that reflected the region's integrated resource plans and load forecasts. This analysis did not include consideration of local transmission constraints—admittedly an optimistic assumption for resource adequacy, but this was balanced by not including interchanges with Southern Company's immediate neighbors, a conservative assumption.

Inputs and Assumptions for Southern Company

Creation of the 2030 Resource Mix to Be Analyzed

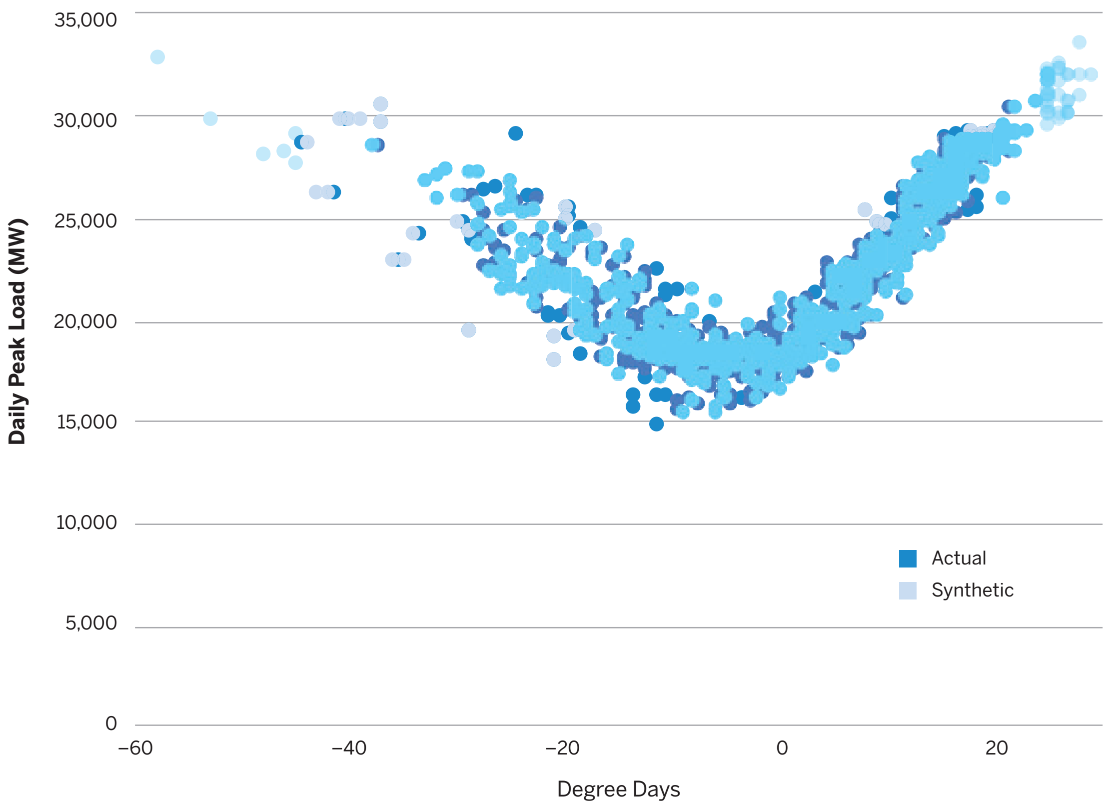
First, we modeled the 2030 resource mix in Southern Company based on existing units and capacity expansion outlined in each utility's integrated resource plan and determined the LOLE risk, with the goal of understanding what the system reliability of the Southern Company zone we created would be if it were an isolated system. We identified the existing generators, resource additions estimated to be online by 2030, and anticipated retirements by 2030.[11] All generators owned (or contracted through power purchase agreements) by Mississippi Power, Alabama Power, Georgia Power, and Southern Company were represented as individual generators in the model. See Table A-4 in the appendix for additional information on data sources and assumptions used for Southern Company.

With the given 2030 resource mix, the zonal Southern Company model exhibited no LOLE risk and therefore functioned as a "perfect" resource connected to ERCOT. Since this is neither realistic nor beneficial for understanding resource adequacy benefits and to demonstrate the methodology described here to quantify resource adequacy benefits, the proposed additions of combined-cycle plants and combustion turbines in Southern Company's integrated resource plans were not included,

11 Notable resource additions to be online by or before 2030 included 5,000 MW of solar PV built in several tranches (Georgia), a 1,000 MW battery storage facility (Georgia), 1,018 MW Vogtle 3 & 4 nuclear units (Georgia), and 774 MW Barry gas combined-cycle turbine (Alabama). The coal and gas retirements indicated by utilities' integrated resource plans to take place by 2030 included a 3,431 MW coal plant (Georgia), 44 MW fuel oil plant (Georgia), 1,629 MW gas steam turbine (Alabama), 21 MW fuel oil plant (Alabama), 421 MW coal plant (Mississippi), and 299 MW gas steam turbine (Mississippi).

FIGURE 24

Southern Company Actual 4-Year and Synthetic 40-Year Daily Peak Load and Degree Days for Creating 1980–2019 Synthetic Weather Year Loads



To create 1980–2019 synthetic weather year loads, daily historical peak load in Southern Company was plotted against the heating (negative) and cooling (positive) degree days. A synthetic data set was extrapolated using trends in the historical data and plotted on top of the historical data showing the additional daily peak load data for missing years in Southern Company load data.

Source: Energy Systems Integration Group.

and additional coal generators were retired. This resulted in an additional 3,100 MW of coal retirements and a delay of 2,430 MW of new gas generation, for a net reduction of 5,530 MW from the original 2030 estimate. With a system that now had a LOLE risk, we could model the effects of adding a major transmission line connecting two resource adequacy–challenged systems to one another.

Creation of a 40-year Load and Generation Dataset

Since we used a 40-year load and renewable generation dataset for the ERCOT portion of the study, it was necessary to take near-term historical data on Southern Company load and create a synthetic 40-year load and renewable generation dataset to cover the same time period. While these data are publicly available for the ERCOT system, they had to be developed new for this study to compare the two systems across all 40-years of load and renewable generation we had for ERCOT. To create 40-year weather assumptions of the Southern Company load profiles, a bootstrapping methodology was developed to correlate daily load profiles to total Southern Company load. To do this, 40 years of daily load data were collected from the Atlanta airport.[12] The

12 To simplify the analysis a single location's weather observation was used. To make this analysis more robust, additional locations should be sampled across various weather zones in the Southeast. While this analysis shows a robust relationship between Atlanta's degree days and Southern Company's daily peak load, additional load forecasting work should be evaluated to capture lag variables, humidity, and other key drivers of load.

heating and cooling degree days of the past four years were then evaluated against daily load (as provided in FERC 714 filings) over the same time period. This relationship allowed for a random sampling across the 40 years of similar days in the four-year dataset, accounting for weekday/weekend loads and temperature. This sampling approach is illustrated in Figure 24 (p. 49), which shows the daily peak load as a function of degree days (difference between the average daily minimum and maximum temperature, minus 65 degrees).

Creation of Historical Renewable Generation Profiles

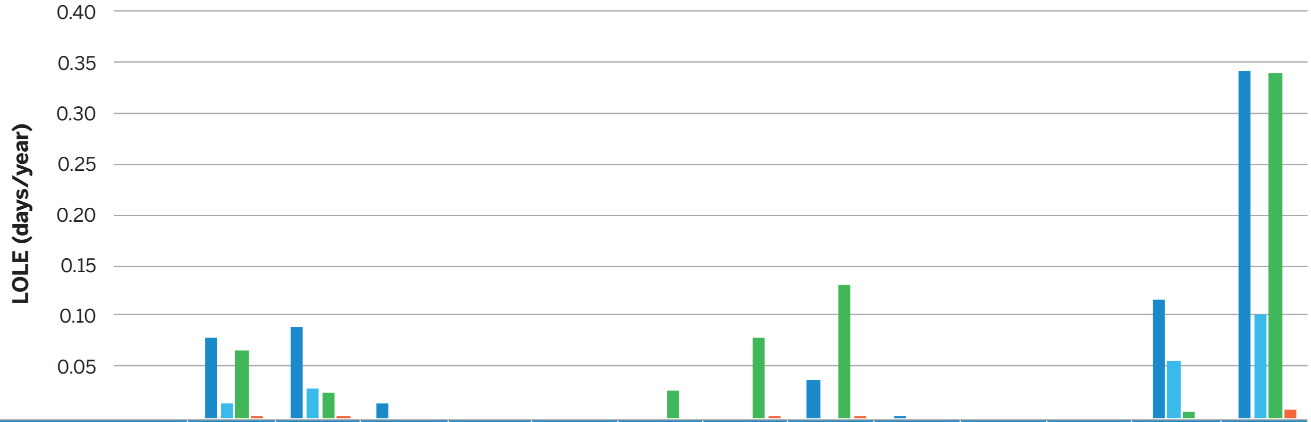
This analysis also required the creation of estimated renewable generation profiles for 2030 in order to understand risk associated with reduced or unavailable renewable generation. The most significant share of renewable generation in the Southern Company footprint is solar. Since generation profiles were available using the National Renewable Energy Laboratory's System Advisor Model (SAM) tool only for the period 1998–2019, to create a set of 40 profiles, the historical profiles were repeated to backfill to 1980.[13]

For the base case scenario, both the ERCOT and Southern Company zones were modeled as isolated power systems in a similar manner to the West Texas Export analysis discussed above. Each system was modeled with a sequential Monte Carlo production cost simulation using 40 weather years of load and renewable generation. Each of these weather years was evaluated across 10 unique random outage draws of thermal generation, for a total of 400 randomized outage samples. Both zones exhibited resource adequacy shortfalls, with both systems above the commonly used 1-day-in-10-year (0.1 LOLE) reliability criterion. Thus, for this analysis, both regions were starting at an unacceptable level of reliability. The next step was to connect the systems by enabling the transmission line between the isolated systems and re-running the 400 samples with the two systems combined. This provides a comparison of reliability between the two systems with and without the HVDC transmission line.

13 While this repeat is not an ideal assumption, the amount of solar assumed in Southern Company was small relative to the amount of wind, solar, and load variability across ERCOT. As a result, this simplification was determined to be acceptable for the purposes of this screening analysis.

FIGURE 25

Loss of Load Expectation by Month for ERCOT and Southern Company Combined, Compared to Isolated Systems



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
ERCOT Only	0.08	0.09	0.02	—	—	—	—	0.04	0.00	—	—	0.12	0.34
ERCOT Combined	0.02	0.03	—	—	—	—	—	—	—	—	—	0.06	0.10
SOCO Only	0.07	0.03	—	—	—	0.03	0.08	0.13	—	—	—	0.01	0.34
SOCO Only	0.00	0.00	—	—	—	—	0.00	0.00	—	—	—	—	0.01

Monthly and annual (far right) loss-of-load days per year (LOLE) are shown for ERCOT and Southern Company as islands and as combined systems. LOLE is significantly improved with the combined systems, almost removing LOLE risk from Southern Company and bringing ERCOT to 0.1 days per year.

Note: SOCO = Southern Company; LOLE = loss of load expectation.

Source: Energy Systems Integration Group.

Resource Adequacy Benefits

The addition of a 2 GW HVDC line between ERCOT North and Southern Company in this simulation provided significant resource adequacy benefits to both zones. Note that in the case study, future systems were intentionally evaluated as an unreliable point by retiring gas and coal generators in order to determine capacity benefits associated with the interregional line. The results indicate almost no loss-of-load events for Southern Company (0.01 days/year) and a LOLE of 0.1 (days/year) for ERCOT. This is a notable finding. By modeling a link between two systems made unreliable for the purposes of this study,[14] the transmission makes both systems reliable—without adding new generation capacity on either side. ERCOT and Southern Company are able to facilitate economic interchange during tight supply conditions, and the overall system load and renewable generation of the combined system is more diverse. This is because the peak demand and resource shortage conditions do not occur simultaneously across a large region.

Figure 25 and Table 14 (p. 52) summarize the resource adequacy metrics for the combined ERCOT and Southern Company example, showing monthly LOLE for the ERCOT and Southern Company systems in both isolated and connected configurations. This type of analysis demonstrates that transmission can be a capacity resource, particularly for connections between systems with weather and resource diversity.

14 ERCOT and Southern Company were intentionally made unreliable by the authors for the case study. This is not meant to imply that the authors believe that the existing, or future, systems will be unreliable.

TABLE 14

ERCOT and Southern Company Combined Resource Adequacy Metrics

	Samples	Events	LOLE	LOLEv	LOLH	LOLP	EUE	NEUE	EUE/ LOLE	LOLH/ LOLE
	Years	Days	Days/ year	Events/ year	Hours/ year	% of days	MWh/ year	PPM	MWh/ event	Hours/ event
ERCOT										
Isolated*	400	137	0.34	0.39	1.51	0.09	4,184	0.009	12,216	4.4
Combined	400	41	0.10	0.128	0.48	0.03	1,032	0.002	10,067	4.7
Southern Company										
Isolated	400	136	0.34	0.395	1.22	0.09	1,091	0.007	3,209	3.6
Combined	400	4	0.01	0.015	0.03	0.003	14	0.00008	1,366	2.8

All resource adequacy metrics for the isolated and combined ERCOT and Southern Company systems are shown. Across the metrics, risk of load shedding is clearly reduced with the interregional transmission line in place.

* It can be seen that the ERCOT-only results vary slightly compared to Table 12 due to changes in the random number seed and maintenance schedules introduced when combining the Southern Company and ERCOT systems.

Note: LOLE = loss of load expectation; LOLEv = loss of load events; LOLH = loss of load hours; LOLP = loss of load probability; EUE = expected unserved energy; NEUE = normalized expected unserved energy; PPM = parts per million.

Source: Energy Systems Integration Group.

Generation Capital Cost Benefits

To quantify the cost of avoided capacity additions as a monetary benefit, it was assumed that the transmission line could potentially defer investment in new generating capacity in both regions. The avoided capacity cost estimate is based on the cost of new combustion turbines, which was assumed to be $100/kW-year and was adjusted down by expected energy and ancillary service revenues of $40/kW-year,[15] for a net cost of new entry of $60/kW-year. The net cost of new entry represents the expected additional capacity cost required to build a new combustion turbine.

To quantify the capacity value of the transmission line, both ERCOT and Southern Company were modeled as islands with 2 GW of combustion turbines added to bring both zones' LOLE back to the level seen with the HVDC line installed. The same 400 sample probabilistic analysis was conducted for both zones, which showed that the addition of 2 GW of combustion turbines to each isolated system brought both LOLEs within the range of the result for the combined system, indicating that the transmission line is providing firm capacity to both sides of the line. Since the transmission line brings both individual systems' LOLE to similar levels as individual capacity additions do in the isolated cases, it indicates that the 2 GW HVDC transmission line has the effect of adding 2 GW of capacity in ERCOT and 2 GW of capacity in Southern Company, or 4 GW across the combined system. Table 15 (p. 53) summarizes the resource adequacy results of the 2 GW combustion turbine replacement runs and associated avoided cost of these additions based on the net cost of new entry of a combustion turbine and the equivalent capacity value of 4 GW that the transmission line brings to the combined system.

The transmission line is facilitating access to 4 GW of underutilized capacity in each zone to make both zones reliable. While Southern Company would not be built to a LOLE of 0.01 or 0.03 because the system would be overbuilt relative to its target LOLE of 0.1, this means that further coal retirements or delayed capacity expansion could be enabled while staying below the reliability threshold of a LOLE of 0.1 day/year with

15 Both the cost of new entry and the expected energy and ancillary service revenues were based on historical ERCOT pricing provided in the annual *State of the Market Report* (Potomac Economics, 2021).

TABLE 15

Capacity Value of New Transmission Versus Combustion Turbines

Zone	Loss of Load Expectation			Net CONE of New Combustion Turbine	Avoided Capacity Additions
	Isolated Systems	With HVDC Connection	2 GW Combustion Turbine Additions		
ERCOT	0.34 days/yr	0.10 days/yr	0.11 days/yr	$60/kW-yr	120 M$/yr
Southern Company	0.34 days/yr	0.01 days/yr	0.03 days/yr	$60/kW-yr	120 M$/yr
Total benefit					**240 M$/yr**

The addition of 2 GW of combustion turbines to each isolated system brought ERCOT and Southern Company within the range of LOLE when the transmission line was in place. This indicates that the capacity benefit of the line is equivalent to 4 GW of combustion turbines, valued at $240 million/year ($120 million/year in each system).

Note: LOLE = loss of load expectation; CONE = cost of new entry.

Source: Energy Systems Integration Group.

the transmission line in place. The total benefit is valued at $240 million per year in 2030 across both systems. By connecting two electrically diverse systems, the value of the transmission line is double its transfer capability. One reason for this benefit is a result of ERCOT's loss-of-load risk residing mainly in winter months (in a high variable-renewable grid) and Southern Company's being in summer months. When one system is most likely to experience a shortfall, the other system is available to support it.

Putting the annual benefits in perspective, a proposed HVDC transmission line between ERCOT and Southern Company's territory in Mississippi is approximately 400 miles long. Using HVDC cost estimates for the West Texas Export upgrade options, the transmission project's total and annual costs in 2020 real dollars are $2.2 billion and $235 million per year, respectively. Solely accounting for the resource adequacy benefits pays for the transmission line between ERCOT and Southern Company in this study.

Key Takeaways

By linking two unreliable systems together, the transmission makes both systems reliable—without adding new generation capacity.[16] This is a significant finding and a strong case for the benefits that large-scale transmission can provide. Instead of relying on building large amounts of additional capacity, connected systems can support each other during extreme weather events. This is because the two geographically distinct regions have sufficiently diverse load and resource mixes to complement the other system's needs when there is a shortfall. In this example, Southern Company can export surplus capacity to ERCOT if ERCOT is facing extreme cold overnight and Southern is not. The same is true in reverse: if Southern is experiencing a heat wave in the summer and is short capacity while ERCOT has surplus solar and wind, ERCOT can export to Southern and alleviate its shortfall. Connecting different regional systems enhances grid flexibility and improves reliability for both regions.

Resilience Benefits

The same methods used to quantify the West Texas Export resilience benefits were implemented in the analysis of the ERCOT to Southern Company line. This method compares the difference in unserved energy for the remaining loss-of-load events on the system, after the number of events has been reduced to the reliability criteria. While bringing the system down to the reliability criteria of 0.1 days/year LOLE is a resource adequacy capacity benefit, the remaining shortfall events can be reduced in magnitude, if not

16 As noted earlier, ERCOT and Southern Company were intentionally made unreliable by the authors for the case study, for the purpose of assessing the benefits of the addition of a transmission line between them.

avoided altogether, with the transmission line, constituting a resilience benefit.

All 400 samples from the resource adequacy models of the isolated ERCOT and Southern Company systems were compared to the samples from the system combined with an HVDC transmission line. The resilience benefit of the line is represented by the change in magnitude of the events that are identical between the isolated system and the combined system. For example, a 26,000 MWh loss-of-load event in the isolated ERCOT system becomes a 5,000 MWh loss-of-load event in the combined system.

There are two ways to represent the resilience benefits of the transmission line: the average resilience value per event, which is the sum of all reduced unserved energy in each system divided by the number of identical events (31 in ERCOT and 4 in Southern Company), and the annualized resilience benefit, which is the sum of all reduced unserved energy divided by the number of years modeled (400 samples is 400 years). Both results are important to consider. The annualized value is the annual benefit of having the line without significant severe events occurring and is important to consider because it provides the probabilistic annual benefit of the transmission line (based on the 400 samples modeled). The average resilience value per event is the avoided cost when extreme events do occur. In the case that load is being shed in ERCOT or Southern Company, the HVDC transmission line connecting the two reduces the total cost to each system. This directly reduces costs to society and can mitigate the severity and length of blackouts. For example, the cost of one loss-of-load event modeled in ERCOT was reduced by $595 million, which accounts for 27 percent of the total cost of the transmission project ($2.2 billion). Put another way, that same event would have cost Texans an additional $595 million in damages related to load shedding if the HVDC line to Southern Company were not in place.

The results of this analysis showed that the transmission line between ERCOT and Southern Company provides minor annual resilience benefits to Southern Company and significant annual benefits to ERCOT. The smaller resilience benefits accrued by Southern Company are actually good news: the transmission line substantially reduced loss-of-load events in that zone, leaving few remaining load-shedding events to compare to the reduction in unserved energy relative to the isolated Southern Company case.

Table 16 summarizes the total avoided unserved energy system-wide and in the two individual zones. The value of lost load was calculated at $20,000/MWh for ERCOT and $39,897/MWh for Southern Company (PUCT, 2021; Georgia Power, 2022).[17]

TABLE 16

Avoided Unserved Energy and Resilience Value in ERCOT + Southern Company System

System Component	Avoided Unserved Energy	Total Resilience Value	Average Resilience Value per Event	Annualized Resilience Value
ERCOT	691,304 MWh	$13.8 billion	$446 million	$35 million
Southern Company	46,358 MWh	$1.8 billion	$462 million	$5 million
System-wide	737,662 MWh	$15.7 billion	$908 million	$40 million

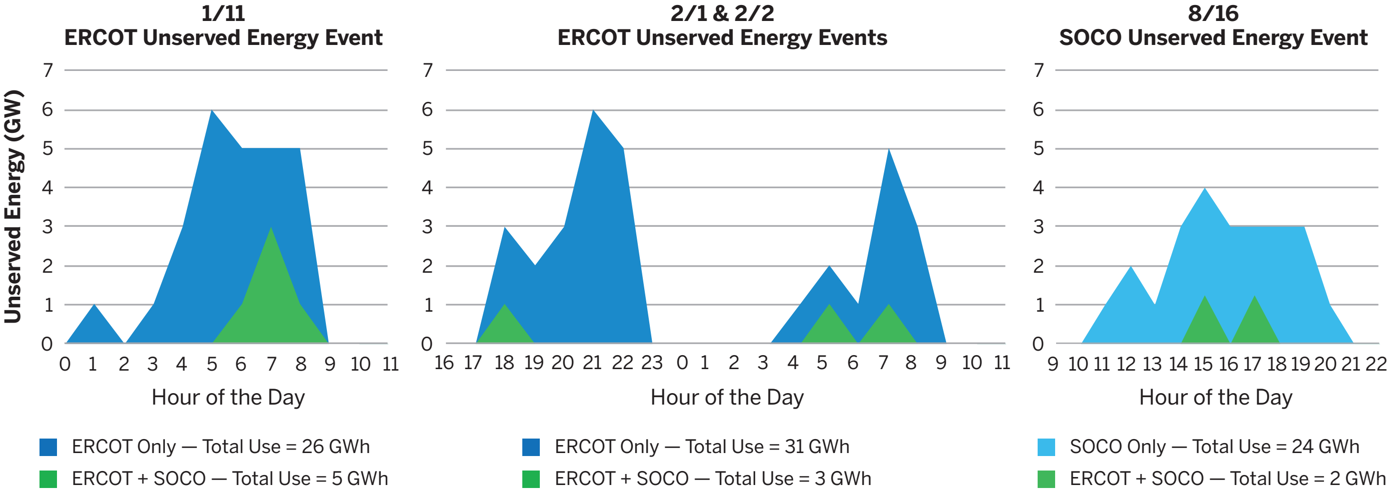
The resilience benefit ascribed to each system is shown in terms of the avoided unserved energy, total value of the benefit, average value per event, and annualized value. The value of total mitigated unserved energy is $15.7 billion for the linked system, with an average of $908 million of avoided cost per event.

Source: Energy Systems Integration Group.

17 Value of lost load for ERCOT was based on the independent market monitors' suggestion and potential decoupling of the current system-wide offer cap which sets a maximum price and actual value of lost load. Value of lost load for Southern Company was based on an average of Georgia Power's 2025 summer and winter value of lost load converted to real 2020 dollars.

FIGURE 26

Visualization of Resilience Benefit from Transmission Line Connecting ERCOT and Southern Company During Four Load-Shedding Events



A comparison of the amount of unserved energy during loss of load events in the isolated systems (blue areas) and combined systems (green areas) for ERCOT and Southern Company on specific sample days shows how the transmission line reduces the magnitude and duration of unserved energy events. The transmission provides capacity during the event and aids in maintaining battery storage levels up to when the events occur.

Source: Energy Systems Integration Group.

Figure 26 is a visualization of four load-shedding events (three in ERCOT and one in Southern Company) and the resilience benefits provided by the transmission line. The data for ERCOT and Southern Company as isolated systems represent the unserved energy event (loss-of-load event) on specific days from the 400 sample resource adequacy models. The combined ERCOT and Southern Company data (shown in green) are for the same unserved energy event as the isolated systems (in blue), but with the two systems linked by the transmission line.

The figure illustrates the degree to which the transmission line reduces the magnitude as well as the duration of the unserved energy event. The burden imposed on the grid and on consumers is significantly reduced, a benefit that goes beyond economics and dollar value.

Real Impact of Extreme Events Avoided

It is important to reiterate that the annualized resilience values do not reflect the true impact of the extreme grid disturbances that the modeled transmission line allows the connected systems to avoid. These avoided events only occur an estimated once every 10 years. The cost of the event is incurred in a single year and constitutes an enormous impact on ratepayers; the cost to ratepayers in this case will be, on average, more than $900 million. The costs of building the transmission are an insurance policy of sorts, a relatively low annual cost to finance the project that mitigates damages (cost to ratepayers) when extreme events hit. This annual "insurance" cost is the $235 million per year cost to build the line (assuming no other benefits are brought by the line), and the "payout" is the $900 million of avoided damages when an event hits, approximately once every 10 years. Based on an assumed asset life of 30 years used in the transmission cost estimate, the line could potentially avert $2.7 billion of unserved energy over 30 years depending on the LOLE of the system. This asymmetric risk, for large, very expensive events that happen only periodically, is often ignored in transmission planning, which instead only views the expected risk ($40 million per year in this case), which fails to capture the real impact, both monetary and social. The actual impact of events to ratepayers when load shedding occurs is skewed much higher, to the tune of almost $1 billion.

This can be illustrated by considering Winter Storm Uri, which impacted Texas and surrounding areas in February 2021. Post-event analysis suggests that a 2 GW transmission line could have saved consumers $2 billion, in addition to saving lives. In the Texas heat wave in August 2019, the same transmission tie could have saved consumers an additional $150 million (Goggin, 2021). While it is not possible to predict and simulate the exact extreme events that will occur, they can easily be estimated using historical data and then quantified in planning activities. Large-scale transmission provides a valuable, resilient, and cost-effective mitigation for risk to consumers.

Additional Benefits

As a final step, we calculated production costs and emissions reductions attributed to the transmission line between ERCOT and Southern Company.

The production cost savings and emissions savings for the combined ERCOT and Southern systems for each of the West Texas Export upgrade scenarios (base case, Option 1, Option 2) were compared against a sum of the results from the isolated systems. The results for individual benefits are provided in Table 17, and the stacked multi-value chart for the Southern Company line is shown in Figure 28 (p. 58).

Production Cost Benefits

The additional benefits assessed for the transmission line show that different transmission lines provide different types of benefits. For ERCOT and Southern Company, connecting the two systems does not significantly impact production cost savings, because the interregional transmission line is not adding significant amounts of available lower-marginal-cost resources to the system when the line is added. This is true also when the West Texas Export is not upgraded and when West Texas Export upgrades are included, shown in Table 17.

Emissions Benefits

The impact on emissions reductions due to the transmission line between ERCOT and Southern Company is also relatively small compared to the resilience and resource adequacy benefits. This, again, is expected since adding the 2 GW transmission line to a large load center (ERCOT or Southern Company) provides all generators with additional load to sell their generation to—and this includes fossil fuel generators, especially cheaper coal and combined-cycle units when renewable generation is unavailable or curtailed. The increase in CO_2 and SOx emissions (represented by negative benefits shown) is attributed to increased coal generation from ERCOT serving Southern Company when prices in ERCOT North are lower than prices in Southern Company. The positive benefits from reduced NOx emissions are a result of some fossil generation shifting out of the more expensive NOx emissions market in the Houston zone toward ERCOT North or in Southern Company.

Generation Capital Cost Benefits

The value of the HVDC line between Southern Company and ERCOT is based, in large part, on the potential it offers Southern Company of accessing lower-cost and

TABLE 17
Additional Benefits from the ERCOT-Southern Company Transmission Line

Scenario	Production Cost Savings	CO_2 Emissions Savings	NOx Emissions Savings	SOx Emissions Savings	Generation Capital Cost Savings
Southern Company HVDC line and no West Texas upgrades	$33.3 million	$537,000 to $1.25 million	$319,000	−$2,000	$75 million
Southern Company HVDC with West Texas upgrades	$46.5 million	−$2.3 million to −$5.4 million	$405,000	−$3,000	$75 million

Production cost savings and emissions savings are minimal when the interregional transmission line is added to the base case and Option 1 and 2 ERCOT system. The generation capital cost benefits reflect the lower-cost wind resources that Southern Company can contract and is a significant benefit of the line.

Source: Energy Systems Integration Group.

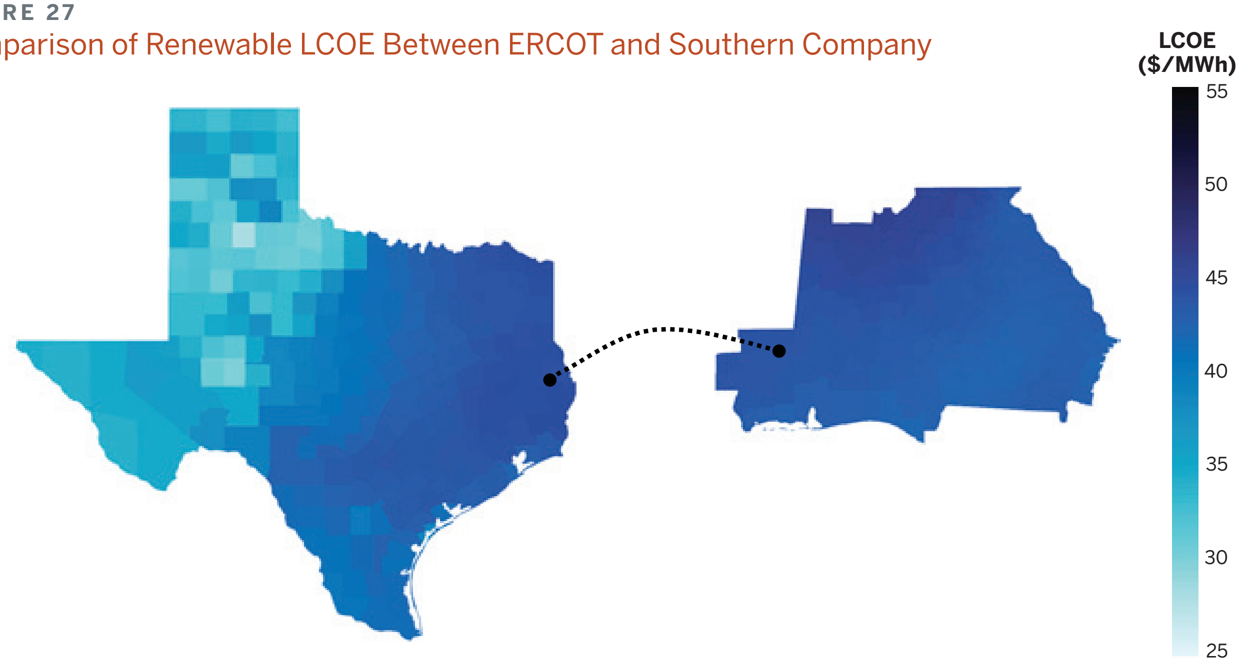
diversified renewable energy. The southeastern United States has limited viable wind energy potential and is confined to solar build-out. The capacity factor of solar in Southern Company's region is also lower than in West Texas. A new large-scale transmission line to ERCOT would allow southeastern utilities to contract for lower-cost renewable wind and solar resources in Texas, as shown in Figure 27. Based on the LCOE data acquired from the University of Texas at Austin that were used for the West Texas example, there is approximately a $10/MWh reduction in LCOE when swapping southeastern solar for West Texas wind. This reduction in generation capital costs assumes the West Texas Export constraints are relieved, allowing for renewables in West Texas to contract with off-takers in Southern Company, increasing their prospective consumer base and creating additional West Texas renewable development signals.

Similar to the West Texas Export example, the generation capital cost benefits of the ERCOT-Southern Company HVDC line can be monetized by comparing against an alternative renewable build-out assumption where developers must build resources in less favorable locations due to transmission constraints in more favorable locations. In this example, the location of the additional renewables shifts to the lower-cost region in West Texas with the transmission line in place, and the aggregate amount of renewable energy generated per year (GWh/year) remains the same, which allows for direct comparison of the capital costs required to create the equivalent amount of renewable energy in different locations.

The study conservatively assumed that 2,000 MW of West Texas wind could be contracted by Southern Company to flow across the HVDC line.[18] In this example, 2,000 MW of wind at a 43 percent capacity factor translates to approximately 7,500 GWh/year of electricity production. The 7,500 GWh/year target production from wind is multiplied against the difference in LCOE between the two regions ($10/MWh), because this is the difference in capital cost required to build enough renewable resources to produce 7,500 GWh/year in West Texas or in Southern Company's territory,

FIGURE 27

Comparison of Renewable LCOE Between ERCOT and Southern Company



The lowest levelized cost of electricity (LCOE) by county for wind and solar resources in Texas is compared to the levelized cost of solar in Southern Company territory. Accessing lower-cost wind resources in West Texas would greatly benefit Southern Company's renewable energy expansion.

Source: Energy Systems Integration Group. Data: Energy Institute at the University of Texas at Austin.

18 This is a conservative assumption because a 2,000 MW line could over-procure wind capacity, or target a diverse wind and solar mix, to maximize line flows with minimal spilled energy.

resulting in a total reduction of generation capital costs of $75 million per year.

Multi-Value Benefits Stack

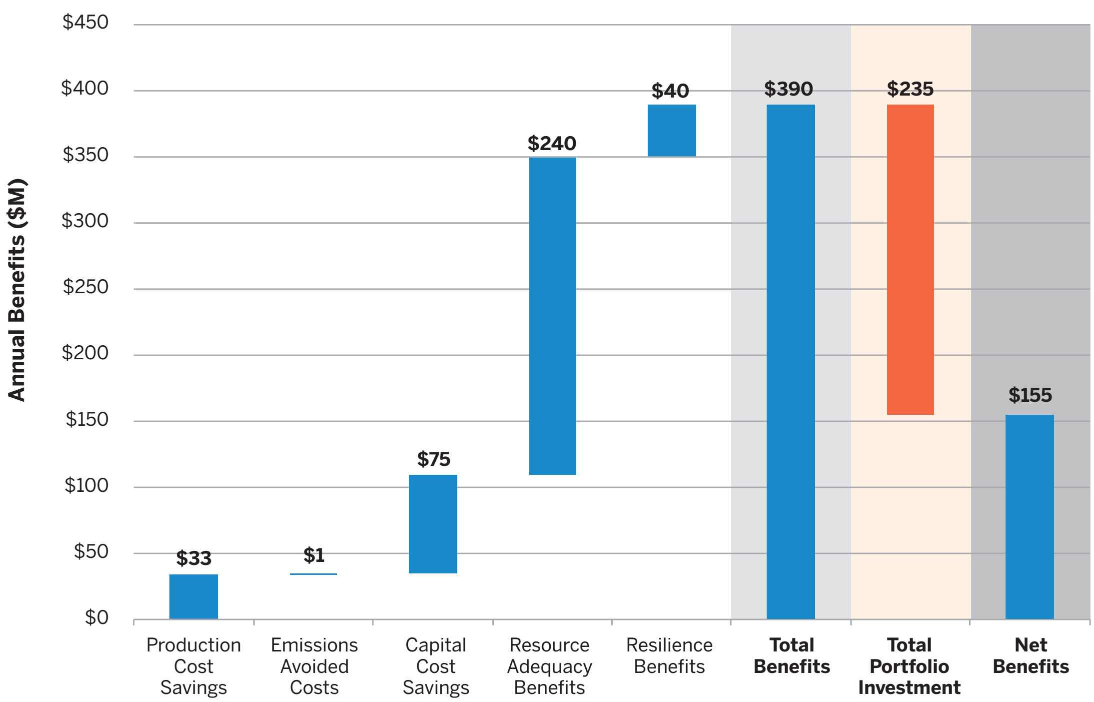
The resulting value stack for the HVDC transmission line between ERCOT and Southern Company is provided in Figure 28. Similar to the analysis of West Texas Export upgrades discussed above, the production cost savings are not high enough to justify the transmission upgrades on their own (with a benefit-cost ratio of 0.14), but the multi-value framework clearly shows that the new line is economic (with a benefit-cost ratio of 1.66).

The types of benefits seen here are distinct from those in the West Texas Export example. In the example from Texas—where transmission is increasing load centers' access to energy—we saw significant production cost, emissions, risk mitigation, and generation capital cost benefits, and not much resilience and resource adequacy benefits. In the ERCOT-Southern Company example discussed here—where transmission is serving to diversify two systems' resource mixes and load profiles—the transmission addition shows little value from production cost savings or emissions reductions, some benefits in terms of generation capital cost savings and resilience, and significant value from resource adequacy benefits. By considering all these benefits, the transmission line's value is represented more accurately.

Moreover, the two types of transmission expansion are not mutually exclusive. Building additional West Texas Export capability is not only economic for Texas (as our first case study example shows), but would be *amplified* by interregional connections, allowing other regions to access renewable-rich regions in a way that also fosters improved reliability and diversity as well as lower emissions.

FIGURE 28

Multi-Value Benefit Stacking for the Transmission Line Connecting ERCOT and Southern Company



Results from stacking the multi-value benefits for the ERCOT-Southern Company transmission line show total benefits of $390 million, compared to $33 million when considering production cost savings only. This increases the benefit-cost ratio from 0.14 to 1.66. Without a multi-value approach, several benefit types that indicate this project is economic would be missed, making it unlikely the line would be built.

Source: Energy Systems Integration Group.

Key Recommendations for Grid Planners and Regulators

The results of this study show that different types of large-scale transmission bring distinct benefits. Some transmission is intended to connect generation in renewable energy regions with load, while other transmission helps to diversify load and resource mixes. For both types, to most accurately assess the benefits of new large-scale transmission, it needs to be evaluated across a range of quantifiable benefits. This will require changes in technical methodologies and institutional change in the way we propose, plan, and allocate costs for new transmission. The analyses presented in this report outline methodologies to support such changes. These methodologies can be used for broader analysis of transmission benefits and applied by system planners according to their systems' resources, constraints, and needs.

Many regions focus exclusively on production cost savings when evaluating new transmission projects, which only quantifies one potential benefit of transmission and can result in economically or environmentally beneficial transmission projects not meeting a region's planning criteria to be built. Given the increased importance of high-quality electrical service and the accelerating energy transition underway, it is important that grid planners and regulators take a broad view of the evolving power grid. This involves assessing multiple major benefits that transmission brings to the grid beyond production cost savings, benefits that reflect the changing needs of the grid in the face of climate change and the need to transition to a clean energy future. This sentiment was recently conveyed by the FERC NOPR (FERC, 2022, p. 23):

> A robust, well-planned transmission system is foundational to ensuring an affordable, reliable supply of electricity. Due to continuing changes in both supply and demand, ongoing investment in transmission facilities is necessary to ensure the transmission system continues to serve load in a reliable and economically efficient fashion. Such investments also support enhanced reliability, as larger, more integrated transmission systems result in a diversity of supply and demand conditions and a certain degree of redundancy that allows the system to better withstand failures during unexpected events. Proactive, forward-looking transmission planning that considers evolving supply and demand conditions more comprehensively can enable potential reliability problems and economic constraints to be identified and resolved before they affect the transmission system, which can facilitate the selection of more efficient or cost-effective transmission facilities to meet transmission needs.

The proposed changes to the long-term regional transmission planning process are a big step in ensuring that ISOs/RTOs and public utility transmission providers enable the power system for the future energy mix and energy demands. The case study presented in this report, and the range of benefits that were quantified for the two large-scale transmission lines studied, makes it clear that a multi-value framework is an integral part of the planning process. Table 18 (p. 60) provides a summary of key results.

The planning process can be improved with the following recommendations for transmission planners, policymakers, and regulators:

1. **Go beyond production costs and implement a multi-benefit framework.**
   Production costs are only one piece of the puzzle, because large-scale transmission upgrades bring a much wider range of benefits. Evaluation of the wide

TABLE 18

Summary of Transmission Benefits Evaluated Across the Study

Property	2030 West Texas Export Option 1 (4 AC Lines)	2030 West Texas Export Option 2 (3 AC Lines + 1 HVDC Line)	2030 Interregional HVDC Line from ERCOT to Southern Company
Production cost savings	$356 million	$452 million	$33 million
Emissions reduction benefits	$188 million	$205 million	$1.25 million
Generation capital cost savings	$493 million	$493 million	$75 million
Risk mitigation benefits	$391 million	$445 million	not evaluated
Resource adequacy benefits	$0	$0	$240 million
Resilience benefits	$0	$2.5 million	$40 million
Multi-value benefit stacking	$1.4 billion	$1.6 billion	$390 million

Source: Energy Systems Integration Group.

range of benefits becomes increasingly important as the system transitions to zero-marginal-cost renewable resources and as grid services historically provided by thermal generation need to be replaced. These benefits should be identified, prioritized, and clearly defined early in the transmission planning process.

2. **Plan for the long term and start today.** Transmission infrastructure is a long-term asset, with many components reaching a 40- to 50-year life at a minimum. The planning horizon should reflect that and go out far enough to see the benefits that arise with specific system changes. Given the long lead time for developing, siting, and constructing transmission projects, it is critical to start today in order to prepare for, and enable, the power system of tomorrow.

3. **Get comfortable with uncertainty and adopt established methods to deal with it.** Like all of us, grid planners do not have a crystal ball to see the future. There is significant uncertainty even in the near term, and that uncertainty is amplified by longer planning horizons. The classic approach to solving this long-standing problem in power systems planning is to use heuristic-based scenario and parametric analysis. However, significant improvements in data science and statistics have been applied in other sectors, such as the tech and finance industries, and are now migrating to the energy field. Modern power planning tools offer significantly improved capabilities to better quantify risks and benefits.

Over the past decade, our system planning has been lulled into complacency by sustained low gas prices and flat load growth. But we are seeing shifts. Geopolitical risks and macroeconomic changes have disturbed the status quo, increasing gas price volatility and accelerating load growth from electrification. Today's grid may not be ready for these changes. As a result, single-point forecasts are too narrow and should be made broader through scenario planning and probabilistic analysis. Large-scale transmission can be a low-regrets option that enables a wide range of future systems; it can make the grid more flexible and able to accommodate greater amounts of renewable generation with less risk that congestion or macroeconomic uncertainty will increase costs.

In addition to bringing system benefits, such transmission upgrades help systems avoid emergencies that occur regularly but not every year. These outlier events are highly costly for ratepayers. Today's transmission planning processes do a poor job of accounting for this uncertainty; for example, the volatility and uncertainty in high natural gas prices can make the decision not to build new transmission to West Texas a costly one. In the modeling of transmission expansion at the West Texas Export interface, natural gas prices of $8.5/MMBtu in the risk mitigation scenario increased the value of the new transmission line by $667 million. This translates directly to $667 million in savings for production costs because renewable generation is not curtailed due to transmission congestion.

When extreme weather strikes, not having built new interregional transmission can have devastating consequences for ratepayers. Transmission can therefore be viewed as an insurance policy, investment in a fixed cost asset that can mitigate a wide range of uncertain future conditions by avoiding or reducing significant loss-of-load events and insulating consumers from volatile swings in fuel commodity prices.

4. **Quantify resource adequacy and resilience benefits.**
   Transmission can do more than reduce costs between regions by transferring low-cost generation in one region to higher-priced load centers or enabling additional renewables development. Large-scale transmission projects can improve resource adequacy by improving capacity interchange between regions, which can replace or defer the need for development of generation capacity in both regions. These projects can also make the system more robust and resilient against extreme events by connecting regions to faraway locales that are likely not to be subject to the same weather patterns or fuel supply constraints. As our grid transitions to clean energy resources for not only energy but also firm capacity, the role of transmission for reliability is becoming much more important.

   The value of the increased resilience can perhaps best be understood from the perspective of its ability to protect the system from highly expensive risks. Large-scale transmission projects offer protection from the extremely high costs incurred by ratepayers during periodic extreme weather events, those that are shown to happen every 10 or so years. In the Texas study described in this report, for example, an interregional transmission investment of $235 million was shown to yield an average $400 million benefit when a shortfall event occurs.

5. **Break down silos and plan interregional projects.**
   Reliability and resilience benefits accrue most strongly from transmission that connects electrically diverse systems, but our current capacity markets and generation planning constructs often do not take into account the value of this diversity. Interregional coordination is a bedrock of the energy transition. The interregional resource adequacy results show, for instance, that both ERCOT and the Southeast systems benefit from an additional transmission link, without adding any new generation resources.

   Today, 90 percent of all transmission investments are made to solve near-term, local reliability challenges either by replacing aging equipment or meeting a local transmission need caused by a new generator addition, load growth, or plant retirement. The industry needs to think bigger and more transformatively, to plan not only what meets today's local needs, but also to meet tomorrow's regional and interregional challenges.

   Enabling a proactive, scenario- and probabilistically based, multi-value framework for long-term regional transmission planning will ensure the power system is reliable, efficient, and increasingly clean for today and into the future.

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Appendix

TABLE A-1

Additional Data Sources and Assumptions for ERCOT

Input and Assumption	Description	Data Source
Detailed generating unit data	Capacity, fuel type, installations, and retirements	Report on the Capacity, Demand, and Reserves in the ERCOT Region, 2022–2031[a]
Load forecast	Forecasted 8,760 hourly loads by weather zone, across 40 weather years	ERCOT 2021 Long-Term Load Forecast[b]
Fuel forecast	Monthly gas prices and annual coal prices by zone	Energy Information Administration's Annual Energy Outlook 2021[c]
Renewable installations	+47 GW of wind, solar, and storage capacity by 2030, sited based on interconnection queue	2020 Long-Term System Assessment for the ERCOT Region[d]
Thermal retirements	−12 GW of coal and gas capacity by 2030	2020 Long-Term System Assessment for the ERCOT Region[d]
40-year weather dataset	Unique 8,760 production profile for each wind and solar plant, 1980–2019 weather years	UL Wind and Solar Profiles developed for ERCOT[e]
Ancillary service requirements	Operating reserves for non-spin, regulation up, regulation down, and responsive reserve service	ERCOT 2022 Methodologies for Determining Minimum Ancillary Service Requirements[f]
Demand response	Installed demand response capacity	2021 Annual Report of Demand Response in the ERCOT Region[g]

a https://www.ercot.com/files/docs/2021/12/29/CapacityDemandandReservesReport_December2021.xlsx

b https://www.ercot.com/gridinfo/load/forecast/2021

c https://www.eia.gov/outlooks/aeo/tables_side.php

d https://www.ercot.com/files/docs/2020/12/23/2020_LTSA_Report.zip

e https://www.ercot.com/files/docs/2021/11/23/CDR_Summer2021_PeakAveWindAndSolarCapacityPercentages.xlsx

f https://www.ercot.com/files/docs/2021/12/02/18_2022_ERCOT_Methodologies_for_Determining_Minimum_AS_Requirements.pdf

g http://mis.ercot.com/misdownload/servlets/mirDownload?mimic_duns=000000000&doclookupId=814219254

Source: Energy Systems Integration Group.

TABLE A-2

Maximum West Texas Export Limits and 90% Planning Limit from the ERCOT Long-Term West Texas Export Study

Maximum Export Limit	2023	2026	2030
Base case	12,240 MW	12,967 MW	13,750 MW
Option 1	16,460 MW	17,370 MW	18,350 MW
Option 2	16,490 MW	17,592 MW	18,780 MW
90% Export Limit			
Base case	11,016 MW	11,670 MW	12,375 MW
Option 1	14,814 MW	15,633 MW	16,515 MW
Option 2	14,841 MW	15,833 MW	16,902 MW

Source: Energy Systems Integration Group. Data: ERCOT (2022).

TABLE A-3

Renewable Build-out by Weather Zone and Technology Type for ERCOT 2030

ERCOT Weather Zone	2030 Solar Installed Capacity	2030 Wind Installed Capacity
Coast	3,206 MW	580 MW
East	270 MW	0 MW
Far west	10,393 MW	10,851 MW
North	10,050 MW	18,035 MW
North central	1,949 MW	5,039 MW
South	1,715 MW	9,942 MW
South central	1,207 MW	703 MW
West	4,338 MW	12,495 MW

Source: Energy Systems Integration Group. Data: ERCOT (2020a; 2022).

TABLE A-4

Additional Data Sources and Assumptions for Southern Company

Input and Assumption	Description	Data Source
Detailed generating unit data	Capacity, fuel type, installations, and retirements	Utility IRP planning documents and EIA Form 860 and 923[a, b]
Load forecast	Forecasted 8,760 hourly loads by utility across 40 weather years	FERC 714 filings and historical temperature data[c, d]
Fuel forecast	Monthly gas prices and annual coal prices	EIA Annual Energy Outlook[e]
Renewable installations	5 GW of solar and 1 GW of battery storage by 2030	Utility IRP planning documents[f, g, h]
Thermal additions	1,018 MW Vogtle 3 & 4 nuclear units and 774 MW Barry gas combined cycle plant	Utility IRP planning documents
Thermal retirements	−3,341 MW coal (Georgia), 44 MW fuel oil (Georgia), 1,629 MW gas steam turbine (Alabama), 21 MW fuel oil (Alabama), 421 MW coal (Mississippi), and 299 MW gas steam turbine (Mississippi)	Utility IRP planning documents
40-year weather solar dataset	Unique 8,760 production profile for each solar plant, 1998–2019 weather years with repeated solar shapes for 1980–1997 weather years	National Renewable Energy Laboratory System Advisor Model and National Solar Radiation Database[i, j]
40-year weather load dataset	1980–2019 historical minimum and maximum daily temperatures and FERC 714 load forecast to create 40 weather years of forecasted load.	FERC 714 filings and historical temperature data

a https://www.eia.gov/electricity/data/eia860

b https://www.eia.gov/electricity/data/eia923

c https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data

d National Oceanic and Atmospheric Administration, Climate Data Online: Hartsfield-Jackson Atlanta International Airport (https://www.ncdc.noaa.gov/cdo-web/datatools)

e EIA Annual Energy Outlook (https://www.eia.gov/outlooks/aeo/tables_side.php)

f Georgia Power 2022 Integrated Resource Plan, January 2022 (https://psc.ga.gov/search/facts-docket/?docketId=44160)

g Alabama Power 2019 Integrated Resource Plan, 2019 (https://www.alabamapower.com/content/dam/alabama-power/pdfs-docs/company/compliance---regulation/IRP.pdf)

h Mississippi Power 2021 Integrated Resource Plan, April 2021 (https://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=658803)

i System Advisor Model Version 2021.12.02 Revision 1 (SAM 2021.12.02), National Renewable Energy Laboratory, January 2022 (https://sam.nrel.gov)

j M. Sengupta, Y. Xie, A. Lopez, A. Habte, G. Maclaurin, and J. Shelby, “The National Solar Radiation Data Base,” *Renewable and Sustainable Energy Reviews* 89(2018): 51–60 (https://nsrdb.nrel.gov)

Source: Energy Systems Integration Group. Data: ERCOT (2020a; 2022).

Multi-Value Transmission Planning for a Clean Energy Future

A Report of the Energy Systems Integration Group's Transmission Benefits Valuation Task Force

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This report and its accompanying fact sheet are available at https://www.esig.energy/multi-value-transmission-planning-report.

To learn more about the recommendations in this report, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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