BEFORE THE COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

Hearing To Examine Interstate Delivery Networks for Natural Gas or Electricity
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Chairman Murkowski, Ranking Member Cantwell, and Members of the Committee –

I am Jim Hoecker, here today on behalf of WIRES. I thank you for the opportunity to address the Committee about the current electric transmission issues and the future state of our high voltage electric grid.

WIRES (www.wiresgroup.com) is a non-profit trade association with an international membership, dedicated to developing and providing information to policymakers and stakeholders about the benefits of investing in the network of wires, substations, and technologies and facilities that deliver large amounts of electricity for domestic, commercial, and industrial uses. Over the past decade, I believe our efforts have resulted in an appreciation for the value of the high-voltage grid and the need to continuously strengthen and modernize it. This Committee's focus on energy delivery networks today is commendable and it suggests to me that we must now move from understanding the importance of infrastructure to more difficult questions -- are we building the right facilities and are we building them in a timely fashion? Are we responding in a proactive way to the potential of a more electrified economy and accommodating and incorporating new technologies? Finally, are we fostering efficient development in order to create net benefits for consumers? To answer those questions, WIRES has sponsored or produced a battery of studies about the benefits of a more robust transmission system to help ensure that we meet the challenges of an economy that is destined to be much more highly electrified in the coming decades. A more extensive, highly integrated, upgraded transmission system is needed to meet the demands of the electrified future. The "challenges" that exist specific to transmission, and my focus this morning, include:

- A continued need to invest to replace aging facilities and reduce costly congestion still exists, despite significant investments of private capital in the past decade;
- A complex regulatory regime has made project authorization a protracted and inefficient process and has failed to produce effective regional and interregional project planning; and
- Even after a decade of desperately needed transmission investment, there is widespread misunderstanding of how transmission benefits consumers of electricity.

The "opportunities" for transmission to serve the public interest in new ways are equally great and deserve to be better understood. They include:

- Transmission's important function as an integrator of renewable resources and distributed technologies make additional investment critically important.
- Investing in a more robust transmission grid will make a major contribution to making the grid more resilient.
- Transmission investment must now be focused on the further electrification of the American economy, making forward-looking and pro-active transmission planning a necessity.

In support of this testimony, I attach for reference the comments that WIRES recently filed at the Federal Energy Regulatory Commission ("FERC") about why transmission investment is critical to the resilience of our electric system (Appendix A) and a recent paper addressing perceptions about the need for, and the value of, continued transmission investment (Appendix B). Appendix C is a graphic comparison of the services provided by transmission and those provided by distributed technologies, demand response, and other localized solutions, demonstrating that transmission is a necessary complement to support these technologies.

Today's Grid Challenges.

The level of transmission investment in recent years essentially made up for a quarter century of underinvestment, replaced aging facilities (some nearing a century old), and addressed short term reliability issues. Industry and policy makers should not rest easy, however. Continued investment is not optional if we are to meet challenges of an electrifying economy, install modern digital technologies, deploy and serve more distributed resources, enhance regional and interregional energy markets, lower electricity prices for consumers (now a declining share of the cost of living virtually everywhere), and strengthen the grid against physical, cyber, and natural disruptions. Many systems still operate with old and inefficient technologies that invite reliability problems and poor transfer capabilities. Consequently, consumers still pay $4 billion in congestion costs each year in organized markets alone, even though congestion costs on the grid have been halved.[1] Although old facilities have been replaced or upgraded at an unprecedented pace in the last decade (about $15-20 billion annually), many of the transmission systems we still rely on today were designed and built from the late 1940s to the 1970s. They have reached or exceeded their useful lives and replacing those assets will cost nearly $60 billion in the next five years alone.[2] Moreover, transmission facilities are often inadequate or non-existent in regions that have enormous potential to produce low-carbon, highly cost-competitive renewable energy resources and natural gas generation.

These challenges are surmountable but the task has proven difficult. Indeed, no energy delivery system is more deliberately planned, regulated and overseen at more levels of government or more subject to debate than the transmission grid. The reasons for this are partly historical; we are building an integrated, regional, and multi-state network at the intersection of local, state, and federal regulatory jurisdictions. I believe Congress recognized the problems that created back in 2005, recognizing the national interest in a multi-state, multi-regional transmission grid, particularly one that could bring location-constrained renewable resources to major load centers. We nevertheless still face these challenges today. The more important and extensive a proposed transmission project is, the more likely

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[1] Gramlich, Rob, "*Bringing the Grid to Life: White Paper on the Benefits to Customers of Transmission Management Technologies,*" (March 2018).

[2] Pfeifenberger, Hannes, Chang, Judy, and Tsoukalis, John, *"Investment Trends and Fundamentals in US Transmission and Electricity Infrastructure,"* (July 2015); Freedman, Mark, Anderson, Norman, Hill, Jeff, Acosta, Daniel, and Ferrer, Santiago, *"Maximizing the Job Creation Impact of $1 Trillion in Infrastructure Investment,"* (March 2017).

that affected states will fall into prolonged disagreement about who benefits and how the public interest should be served. It's an old story with few solutions and a considerable amount of uncertainty. For example, FERC's Order No. 1000 sought to address these issues and placed the issue of interregional transmission planning on the table for discussion. Unfortunately, Order No. 1000 did not suggest a workable path forward beyond the need to establish regional planning processes.

Another challenge is protracted transmission development cycles. Compared to the 3-4 years needed to permit and construct natural gas pipelines, the planning, siting, permitting, and construction of transmission lines frequently require a decade or more. Environmental reviews are a part of the problem, in my estimation, not because of the complex resources they legitimately protect but because they are largely uncoordinated in their procedures, regulatory authorities, and timelines.

Additionally, an important consideration surrounding any investment in infrastructure is its cost. Coming after a quarter century of underinvestment when the nation invested next to nothing in the grid, the new investment cycle was needed and undertaken. Despite the new round of grid investment that corrected what was proving to be a hazardous course, transmission still remains the smallest component of electricity bills on average (10-12%), while the overall cost of electricity continues to fall. Critics have characterized transmission costs as "exploding" in the Western U.S., in the context of recent collaborative efforts in that region to greatly expand and integrate energy markets. But this is only half the story, as these developments have led directly to regional economies of scale, more competition, and efficiency in delivering energy from remote parts of the West. Among the most significant benefits of transmission in this modern era are, and will continue to be, delivery of cost-competitive resources – including renewable resources, energy storage, and new technologies -- that will save consumers money, enhance reliability, and help reduce emissions regionally. Given that generation costs are a significant component of electricity bills, the net benefits to consumers will dwarf transmission costs in the short run and especially over time.[3] In fact, a robust transmission system will be a platform upon which even

[3] Several studies support this contention. The Southwest Power Pool ("SPP") concluded in its paper *The Value of Transmission* that a group of major transmission investments in that region between 2012 and 2014 would yield $12

neighborhood distributed resources can participate in the competitive electricity market.

Today's Grid Opportunities

Transmission gives us the optionality to adapt to whatever the future holds, and a modern and resilient transmission system will be the most valuable energy asset we have. Indeed, the decentralization of electric generation resources and the new technologies do not spell the end of the wired network of transmission lines. Those resources and technologies will depend more than ever on the grid for their economic justification and deployment. In an effort to learn more about the economic and operational relationship between transmission and new technologies like energy storage, demand response, and distributed and utility-scale generation (known collectively as "market resource alternatives"), WIRES sponsored a study[4] which remains state-of-the-art. It shows the complementarity of transmission and emerging technologies. In most cases the two work together to provide net consumer benefits. Put another way, each technology is capable of providing specific services, and transmission is capable of providing virtually all services.[5] As new technologies grow and become cost-competitive, they too will depend on the grid for market access.

The high-voltage grid must also be storm- hardened and modernized for an environment that can be hostile to our electrified society. In WIRES' recent comments to FERC in its consideration of grid resilience issues, WIRES argued that the Commission must be proactive in this area, given that its jurisdiction over transmission planning is far more extensive than that for generation and fuel supplies. We made several specific proposals, which the Commission is currently evaluating along with the

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billion in net present value benefits to consumers over 40 years and a 3.5:1 benefit to cost ratio. *"The Value of Transmission,"* A Report by Southwest Power Pool (January 2016). Similarly, the Midcontinent Independent System Operator, another regional grid manager whose territory spans much of the central U.S. and Canada, analyzed several current grid upgrades and found net consumer benefits ranging from 2.2 -3.4:1. MTEP17 MVP Triennial Review, *"A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio,"* produced by Midcontinent Independent System Operator (September 2017).

[4] London Economics International (Frayer and Wang), *Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process,* produced for WIRES (October 2014).

[5] "We observe that individual MRAs are generally not capable of providing all of the same services that transmission provides for the same tenure and geographical dimension. With the exception of utility-scale generation in limited circumstances, no single MRA is a workable substitute for transmission. *Id.*, at p. 12. *See* Appendix C for a graphic representation of these services from the study.

comments of many others. To distill it down, we recommended that (1) the Commission make decisions about the extent to which resilience is deliberately planned for; (2) generic transmission planning principles include the objective of a more resilient grid; (3) the Commission should take a fresh look at its authority to plan for resilience; and (4) clarify the responsibilities of regional planners.[6]

In sum, WIRES urged FERC to consider that viable markets supported by robust energy delivery networks are at least as capable of strong and flexible responses to natural events and man-made assaults against our energy economy as other solutions that have been proposed.

Finally, WIRES wants to draw your attention to the (increasingly likely) prospect that the electricity industry will escape the prevailing paradigm of anemic utility sales growth. Flat demand for electric power is a product of a number of factors, most notably the progress in photovoltaic solar development and energy efficiency.[7] Under new laws and technologies, consumers can often choose to self-generate and reduce their demand for utility services. This tends to depress demand growth but it may also mask another transformational change that will afford transmission additional opportunities. In its recent paper, The Brattle Group projects a doubling of electricity demand by 2050 if transportation and heating were to become largely electric. Growing demand for electric vehicles, the declining cost of renewable generation, a potential imperative to reduce carbon in the atmosphere, improvements in battery technology, and other developments already call into question current supply and demand

[6] Comments of WIRES, *Grid Resilience in Regional Transmission Organizations and Independent System Operators* (Docket No. AD18-7-000), May 9, 2018. These comments were accompanied by a study from The Brattle Group, *Recognizing the Role of Transmission In Electric System Resilience,* which stated that "[t]he power system can be vulnerable to disruptions originating at multiple levels, including events where a significant number of generating units experience unexpected outages. The transmission system provides an effective bulwark against threats to the generation fleet through the diversification of resources and multiple pathways for power to flow to distribution systems and ultimately customers. By providing customers access to generation resources with diverse geography, technology, and fuel sources, the transmission network buffers customers against extreme weather events that affect a specific geographic location or some external phenomenon (unavailability of fuel and physical or cyber-attacks) that affect only a portion of the generating units." At p. 3

[7] The National Renewable Energy Laboratory ("NREL") hypothesizes that PV generation could comprise 30 percent of projected 2050 consumption, depressing annual demand growth to 1.0 percent or less for the indefinite future. On the other hand, analysts also think that NREL's estimate of PV's potential is "unlikely" and "even if achieved utility sales of electricity would still represent over 60 percent of electricity production. A future without utility scale electricity production and, perhaps more importantly, without transmission and distribution network connecting centralized generation with load, is therefore very unlikely." The Brattle Group, *Electrification: Emerging Opportunities for Utility Growth*. January 2017, at p. 3-4.

assumptions. The requirements of intermittent nature of both distributed resources near load centers and utility scale renewable generation in low-cost regions of the country will make the transmission network a valuable infrastructure with which to diversify resources and reduce the cost of integrating and dispatching those resources. This is the "electrification" scenario, now so widely talked about and studied. WIRES plans to embark on a major study this year to better understand and define how this delivery network must be configured and planned in anticipation of this potential transformation in how we use electrical energy.

To conclude, WIRES believes it is necessary to take proactive steps to achieve the policy and regulatory certainty that will support needed transmission investment. We must look beyond the debates that have surrounded implementation of Order No. 1000, and instead build on the positive achievements of the last two decades and act pursuant to the larger trends that are shaping our electric system and the larger economy. As the mix of electric generation resources continues to change, as the economy becomes more electrified, and as new technologies seek their place in the energy system, transmission is the common element that will support all future needs and provide a hedge against uncertainties and potential costly outcomes. The time is now to be proactive in encouraging additional investments in our nation's most crucial infrastructure: the electric transmission system.

Thank you for this opportunity.

APPENDIX A

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	**)))**	**Docket No. AD18-7-000**

COMMENTS OF WIRES

WIRES[1] respectfully submits the following comments in response to the January 8, 2018 *Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures* issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") in the above-captioned docket.

WIRES strongly supports the Commission's efforts to ensure increased resilience of the electric power system, including its rejection on policy and legal grounds of the Secretary of Energy's proposal to provide out-of-market relief for certain sources of electric generation.[2] WIRES believes grid resilience will only increase in importance as the economy continues to become more dependent on reliable electric power. At the same time, cyber and physical threats, as well as natural events of unparalleled ferocity and unpredictability pose new challenges to our increasingly electrified economy. Since electric power disruptions are most likely to arise through the disruption of distribution and transmission systems, the Commission's determination to help achieve greater resilience in bulk electricity markets must focus on the key role of critical transmission infrastructure in supporting overall system resilience. In fact, it is particularly appropriate and important that the Commission re-focus this resilience proceeding on the planning, financial support for, and development of electric transmission because the

[1] WIRES is an international non-profit trade association of investor-, publicly-, and cooperatively-owned transmission providers, transmission customers, regional grid managers, and equipment and service companies. WIRES promotes investment in electric transmission and progressive state and federal policies that advance energy markets, economic efficiency, and consumer and environmental benefits through development of electric power infrastructure. For more information, visit www.wiresgroup.com.

[2] Grid Resiliency Pricing Rule, 82 Fed. Reg. 46940 (proposed October 10, 2017) (to be codified at 18 C.F.R. pt. 35).

interstate high-voltage grid is more squarely within its plenary jurisdiction[3] and responsibilities than is resource adequacy at the generation level, notwithstanding the importance of addressing fuel supply problems that threaten generation reliability. Specifically, WIRES believes that proactive transmission planning must be made more integral to any resilience strategy, just as resilience must be a strong component of transmission planning. To that end, WIRES recommends Commission action in the following areas:

- In assessing how to move forward in the area of grid resilience, especially as it pertains to the role of more robust transmission infrastructure, the Commission should swiftly and aggressively evaluate the extent to which RTOs and ISOs should be obligated to integrate (or to demonstrate that they have integrated) resilience planning into their regional and interregional transmission planning processes.[4] Each region should be afforded flexibility to implement such integration in a manner that reflects the characteristics of that region, subject to oversight of the Commission.

- The Commission should update its Order No. 890 transmission planning principles to include resilience as a separate and distinct planning driver for RTOs and ISOs.

- The Commission should clarify that it has authority under the Federal Power Act to include resilience in its lawful transmission planning regime, similar to its authority to promote reliable operation of the Bulk Electric System (BES).

- FERC should also clarify that regional planning responsibilities of RTOs and ISOs include planning for resilience, especially in WIRES' view the prevention or mitigation of loss or disruption of critical transmission infrastructure and its services.

In support of these recommendations, WIRES respectfully submits the following Comments and the appended paper on transmission and resilience written by economists and utility analysts at The Brattle Group, entitled *Recognizing the Role of Transmission in Electric System Resilience.*

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[3] *New York v. FERC*, 534 U.S. 1, 16-17, 19-20 (2001); *S. Carolina Pub. Service Authority v. FERC*, 762 F.3d 41 (D.C. Cir. 2015).

[4] *E.g.,* "[T]he Commission should articulate in this docket that the regional planning responsibilities of RTOs include an obligation to assess resilience. After confirming that resilience is a component of such planning, the Commission should also consider initiating rulemakings or other proceedings to further articulate the role of RTOs in resilience planning to include, among other things, thresholds to mitigate and build." Comments and Responses of PJM Interconnection, L.L.C., (PJM Comments) at p. 81.

I. Defining Resilience to Incorporate Transmission Network Considerations

A. Grid Resilience Has Many Components

The Commission's goals in this proceeding are to (1) develop a common understanding or definition of resilience, (2) determine how each ISO and RTO assesses resilience in its footprint, and (3) ascertain whether the Commission ought to take action in furtherance of a more resilient grid, based on the information submitted herein. In WIRES' view, resilience as generally defined[5] entails the identification and mitigation of vulnerabilities and threats to the system, plus the ability to absorb, adapt to, and recover from disruptive events as they occur. There is a critically important human resource and coordination component to resilience as well. Resilience is distinguishable from reliability in the sense that a reliable system may not be resilient, and resilience does not ensure that lights stay on day-to-day. Fundamentally, resilience focuses on low-frequency, high-impact disruptions; however, the Commission is cautioned not to unduly limit the category of system vulnerabilities or potential impacts for which it might require planning, preparation, or recovery measures, recognizing that the frequency and extreme impact (in economic, environmental, or human terms) of events and developments that are unprecedented or occur without warning can be difficult to predict.

Commenters in this proceeding offer several similar definitions of resilience. Whichever the Commission concludes will help it support strengthening of the grid, there is no silver bullet for achieving an optimally resilient electric system. Industry and the Commission must plan for the unforeseeable by taking into account the various processes, practices, and investments that could contribute to preventing or effectively resolving the effects of system disruptions without undue delay. Most RTO/ISO comments focus on what has been called "precaution-based

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[5] Resilience is defined by the DOE and the National Infrastructure Advisory Council ("NAIC") as the ability to reduce the magnitude and/or duration of disruptive events, including physical changes to infrastructure known as "hardening." Reliability is defined by the North American Electric Reliability Corporation ("NERC") as a function of adequacy, which is the ability of the system to supply aggregate electric power and energy at all times. *See* U.S. Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017, at pp. 61-63 ("*DOE Staff Report*") *See also*, the important consensus study report of The National Academy of Sciences, *Enhancing the Resilience of the Nation's Electricity System* (2017), which takes a comprehensive view of grid resilience, offers a series of practical recommendations in moving toward a more resilient grid, and recognizes the importance of involving state and regional grid operators, emergency preparedness organizations, and national and state regulators. (https://doi.org/10.17226/24836.) For a description of NERC's enterprise activities that support the NAIC outcome-focused framework for addressing resilience challenges, see Mark Lauby, "Resilience Framework", WIRES Winter Meeting, at http://wiresgroup.com/docs/WIRES%20Winter%20Mtg%202018%20Lauby.pdf

strategies" to advance resilience, meaning identifying vulnerabilities and employing industry best practices to thwart or mitigate the economic or adverse health effects of potential power disruption, and "discourse-based strategies" that raise awareness, share information, and initiate collective action.[6] On the whole, the recommended solutions involve operational flexibility and coordination, improving generation services, and market reforms.[7] In WIRES' view, these precautionary, coordination, and mitigation strategies must also focus directly on infrastructure investment solutions. Most disruptions of consumers' access to electricity occur at the distribution level[8] but are a distinguishable resilience challenge from disruptions of the high-voltage transmission service which, while quite infrequent, can result in widespread and possibly prolonged power outages and resulting damage. The transmission system must therefore be prepared to withstand disruptions and to mitigate the potentially broad or severe consequences that flow from severe weather, physical attack, or disruption of generation supplies or system operations. In such cases, the resilience that a robust and integrated transmission network provides is of critical importance.

Regional power markets, grid infrastructures, and operating circumstances differ but, as a rule, generation and fuel supply policies offer only a limited hedge against potential disruption. Moreover, while distributed resources are important for rapid recovery, they are of limited long-term capability without the grid's transfer capabilities.[9] A robust grid offers resource diversity and operational flexibility that is critically important to both prevent and recover from service disruptions. Transmission investment ensures system stability and productivity during normal operations and optionality when disruption strikes. New investments in transmission expansion and upgrades that reflect deliberate consideration of the benefits of this optionality will add

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[6] PJM *Comments* at p. 14 *et seq.*

[7] On the operations side, transmission owners and operators manage and operate key resilience and reliability measures, including emergency drills, spare parts inventories, mutual assistance, long-term system planning, routine monitoring, operation scheduling, dispatch and maintenance, and system restoration and recovery. Silverstein, "Transmission and power system resiliency," presented at WIRES Winter Meeting, at http://wiresgroup.com/docs/WIRES%20Winter%20Mtg%202018%20Silverstein.pdf

[8] According to the Department of Energy's *Quadrennial Energy Review* (2017), failures on the distribution system are typically responsible for more than 90 percent of electric power interruptions, both in terms of the duration and frequency of outages. Such interruptions of service, while unpleasant, are relatively routine, often predictable, and typically of short duration. *See* the appended study by The Brattle Group (Chupka and Donohoo-Vallett), *Recognizing the Role of Transmission in Electric System Resilience*, prepared for WIRES (May 9, 2018), at p. 7.

[9] *See* London Economic International, *Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process*, a Report for WIRES (October 2014) available at www.wiresgroup.com

immeasurably to system reliability and resilience. Conversely, an inadequate network of transmission facilities left unprepared and not fully modernized to ensure resilience against threats to system stability and operations will increase the risk of greater and more prolonged economic losses from unanticipated events.[10] To the extent resilience is predicated on having multiple ways to respond effectively to adverse events and developments not yet foreseen, or perhaps not foreseeable, a robust transmission network that affords operators the ability to marshal diverse resources may be the best investment compared to even fuel-secure generation resources.

WIRES' recognizes that a variety of measures will contribute to making the electric system more resilient, including access to diverse sources of electric generation, essential ancillary services such as frequency and voltage support, resource flexibility in the form of storage and other new technologies, storm hardening of infrastructure, mutual assistance programs, and reliable supplies of fuels like natural gas as well as long-term plan to address the vulnerability of substations and transmission system to high impact, disruptive events. It expects the Commission will receive numerous thoughtful comments in this proceeding.

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[10] The vulnerabilities of specific grid components demonstrates the risks of inadequate transmission: For example, substations and transmission systems are critical to get power from generators to load, so increasing the resilience of the transmission system is just as important as improving the resilience of supply resources. A generator with sufficient fuel supplies cannot contribute to increased reliability and system resilience if the congested transmission system prevents it from delivering its energy. As the generation and fuel mix in regional markets changes and evolves, and as climate and technological disruptions pose new challenges to the grid, another cycle of transmission expansions and upgrades will be a top priority.

Second, measures that ensure protection of the transmission system from potential physical or cyber intrusion provide more consequential risk mitigation than the concerns about the unavailability of on-site fuel. Damage to transmission and distribution structures and substations can take weeks to repair, even assuming replacement parts are available.

Third, some parts of the transmission system are extremely over-used, potentially leading to severe operational constraints that make it vulnerable to outages of individual elements. Transmission planning predicated on establishing a more flexible and more liquid bulk electricity markets would result in at least as great an enhancement to reliability and resilience of the electric system as any other major investment. The CEO of the North American Electric Reliability Corporation ("NERC") acknowledged as much when describing the most pressing reliability issues in North America. In a letter to the Secretary of Energy, cited in the DOE Staff Report, the NERC CEO made clear that electric transmission is one of the critical methods of addressing reliability concerns in a more decentralized electric system environment where generation is also being retired, when he stated: "Because the system was designed with large, central station generation as the primary source of electricity, significant amounts of new transmission may be needed to support renewable resources located far from load centers.." *DOE Staff Report*, at pp. 62-63.

Recommendations for action may vary widely depending on local and regional risks and conditions. That said, WIRES maintains that robust transmission facilities and interconnections will be essential to mitigating risks faced by virtually any electric power system.

The RTO/ISO responses in this proceeding generally emphasize the need for timely operational responses to disruptions. However, they acknowledge that resilience will also be measured by the robustness of the physical infrastructure and its inherent ability – as an integrated network -- to withstand shocks or absorb them and still provide operators with options for bringing additional generation and technological resources to bear on a problem. The existence of alternative supplies of energy and the means to deliver them through transmission, the grid's inherent flexibility, and broader access to an assortment of technologies – from storage to microgrids, demand response, and other distributed resources – are the essential characteristics of a fully developed and integrated wired network.

B. The Benefits of Transmission Should Be Central to This Proceeding

The multiple benefits of electric transmission investments are well-documented. The blackouts of the 1960s (e.g., in New York City) triggered the expansion of regional transmission interconnections such that neighboring regions could assist each other under adverse circumstances. A number of studies have found that expansion and integration of transmission links today would provide additional benefits due to the diversity of loads and resources and the dispatchability of new technologies.[11] These studies support the proposition that the U.S. is not investing in enough transmission infrastructure, particularly transmission designed to deploy new technologies or interregional transmission, to ensure that all customers have access to lower cost energy resources and that wholesale energy markets can discipline electricity prices.[12] In fact, the 2017 DOE Staff Report acknowledges that the flexibility and resource

[11] The results of several U.S. and European analyses of the benefits of diverse kinds of transmission projects are summarized in The Brattle Group, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning Is Key To The Transition To A Carbon-Constrained Future*, June 2016 ("Brattle 2016 Study"), Section III, at pp. 6 – 11. Domestic studies by the Southwest Power Pool, the Midcontinent ISO, the Eastern Interconnection States Planning Council, the Eastern Interconnection Planning Collaborative, and the Western Electricity Coordinating Council show that forward-looking planning of regional and interregional transmission that takes into account the range of benefits of transmission results in substantial net benefits to consumers, the economy, and the environment.

[12] Interregional transmission planning is still in its infancy and, despite the call for it in Order No. 1000, interregional projects are not developing as expected or as needed. Improving interregional planning and expanding interregional interties would provide a unique opportunity to improve the resilience of the nation's grid. *See also*, The Brattle Group, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of An Insufficiently Flexible Electricity Grid*, April 2015 ("Brattle 2015 Study");

integration benefits provided by transmission contribute to both resilience and consumer savings:

> Transmission investments provide an array of benefits that include providing reliable electricity service to customers, relieving congestion, facilitating robust wholesale market competition, enabling a diverse and changing energy portfolio, and *mitigating damage and limiting customer outages (resilience) during adverse conditions.* Well-planned transmission investments also reduce total costs. . . .
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> A robust transmission system is needed to provide the flexibility that will enable the modern electric system to operate. Although much transmission has been built to enhance reliability and meet customer needs, continued investment and development will be needed to provide that flexibility.[13]

C. The Special Insurance Value of Robust Grid Infrastructure

Transmission provides a significant measure of insurance against risks associated with future uncertainties.[14] For instance, regardless of how fast load grows or precisely how much renewable generation is built in one location versus another, a robust transmission grid facilitates the delivery of low-cost electricity. Such insurance comes with widening options for the future, which in turn will be very valuable as both federal and state policymakers consider a variety of possible strategies for meeting future energy needs,

The industry (through NERC reliability standards) has been improving reliability-based planning of the transmission grid. Planning to meet immediate reliability objectives differs from economics-driven planning or planning transmission to meet public policy goals. In 2015, a study written for WIRES by The Brattle Group discussed extensively the "insurance value" of a more robust transmission grid from an economic planning perspective.[15] Economic transmission planning should be modified to ensure consideration of this insurance value against economic disruptions caused or exacerbated by insufficient transmission. If transmission planning were to include serious consideration of the long-term benefits of a more

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The Brattle Group, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investment,* July 2013; *Also*, Southwest Power Pool, *Benefit Metrics Manual*, May 8, 2017. All are available at www.wiresgroup.com.

[13] DOE Staff Report, at p. 75 (emphasis added).

[14] For further discussion of transmission planning as a risk mitigation tool, *see* the appended study by The Brattle Group, *Recognizing the Role of Transmission in Electric System Resilience*, at pp. 16-19.

[15] Brattle 2015 Study, at pp. 17, 36-37, 40.

resilient regional and interregional grid, such an improvement would likely produce significant reliability and resilience benefits that would dwarf the benefits of prolonging the operation of power plants that the market has already determined are uneconomic and excessively costly to operate.

II. SPECIFIC COMMENTS AND RECOMMENDATIONS

A. Holistic Transmission Planning Supports Resilience

In a 2015 study for WIRES, The Brattle Group delineated the benefits of holistic and anticipatory transmission planning:

> One of the most strategically significant aspects of major new transmission projects that is seldom taken into account explicitly in the planning phase is the multiple purposes that transmission might serve. That is, a well-designed transmission system enhancement will not only enable the reliable transfer of electricity from Point A to Point B—it will also strengthen and increase the flexibility of the overall transmission network. Stronger and more flexible networks in turn, create real options to use the transmission system in ways that were not originally envisioned.[16]

Consistent with Brattle's findings, WIRES has long advocated for transmission planning that seeks to evaluate and capture the full range of potential benefits of proposed projects. Resilience is another such driver, but RTOs and ISOs are under no current obligation to conduct the kind of risk-based analyses that commenters are developing in this and other proceedings. In general, the current practice of focusing almost exclusively on reliability needs tends to steer policymakers and regulators away from regional and interregional transmission planning approaches that can reduce risks and long-term customer costs. Planning for reliability is a well-understood first resort because the benefits are near term and quantifiable. Beyond the important task of hardening local systems, developing infrastructure, and instituting practices that ensure resilience present a different set of planning problems because risks differ among locales and regions and across time. Identifying system vulnerabilities is a first step.

However defined, grid resilience entails "hardening" the larger, interconnected system against low-frequency, high-impact (and potentially high cost) threats and configuring that system to prevent or reduce disruptions. Planners are always faced with uncertainty, but making the grid more resilient requires them to discern potential risks and clear trends

[16] *Brattle 2015 Study*, at p. 5. Economists at the Brattle Group strengthen that point in the paper appended to these Comments.

surrounding major threats, and to try to understand these uncertainties in terms of their potential magnitude and timing. If transmission infrastructure can be more proactively-planned, policy makers, operators, and customers will ultimately have a much wider range of valuable options with which to cope with future challenges. They will be able to choose among those options with lower risks and costs. Ensuring, for example, that major load centers are served flexibly by diverse kinds of resources that are accessible through several major and possibly redundant delivery paths is critical insurance against extended disruptions and escalating consumer costs.

B. New Approaches to Planning Infrastructure for Resilience

As noted earlier, while resilience is closely related to a traditional conception of reliability, it is also fundamentally unique because it seeks to achieve a different end state – namely, a power grid that can withstand or quickly recover from low-frequency, high-impact events, and one in which key system vulnerabilities have been considered and mitigated. Efforts to proactively plan the transmission grid to be more resilient will require consideration of a unique set of parameters and criteria. Broadly conceived, transmission planners seeking to bolster resilience must: 1) conduct an assessment of system vulnerabilities, 2) evaluate a set of low-frequency, high-impact events and model their impacts on the system, and 3) develop criteria to evaluate mitigation strategies to address the identified vulnerabilities. Complicating matters, resilience planning can be evaluated by traditional benefit-cost analysis only when the potential threat is identified; however, it is difficult to identify low probability threats or to assess the likelihood of such potential threats.

To be clear, current forms of transmission planning may have the "side effect" of promoting resilience because transmission, by its very nature, is integral to the successful delivery of power from generation to load. However, existing transmission planning drivers (reliability, economics, and public policy) are not necessarily designed or intended to provide a basis for addressing resilience as a primary rationale for investment. Thus, today's processes may not result in the desired end state – a more resilient power delivery system. To remedy this, WIRES believes that resilience must now be expressly considered as a transmission planning driver, to be studied and incorporated within any regional and interregional RTO planning process. RTOs and ISOs should report annually on the extreme events considered in their specific resilience-focused scenarios and on the actions, if any, arising from their review of the grid's performance and resilient characteristics.

WIRES notes that, in answering the Commission's request, the RTOs and ISO's have offered a range of views on how, or whether, resilience is currently being addressed within each of their regions. Like these commenters, WIRES acknowledges the importance of efficient operations, better monitoring and control technology, physical interconnectedness between systems, and trained personnel[17] in promoting resilience. PJM notes in its comments that resilience is related to reliability, but it also affirms the distinctive nature of resilience. PJM also recognizes the crucial role that transmission planning plays in ensuring resilience.[18] On both counts, WIRES agrees. By contrast, other regions largely confine their responses to a description of existing processes, and thus do not fully address resilience or its implications for transmission planning. ISO-New England, meanwhile, focuses largely on fuel security, an important issue in its own right (especially in that region) but only one part of a comprehensive approach to resilience.

WIRES contends that RTOs and ISOs should play a central role in addressing resilience through transmission-focused solutions, as part of a broader resilience strategy. Of course, utility efforts to harden systems, replace aging infrastructure, and coordinate operations offer clear resilience benefits and should be recognized in any policy actions taken by the Commission.[19] However, as regional transmission planners and operators, RTOs and ISOs are well-placed to identify regional vulnerabilities and consider mitigation strategies as part of their regional transmission planning processes.[20] In fact, effective transmission planning can be the

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[17] These strategic components of resilience are exemplified by the recent observation by Admiral Jim Eckelberger , Board Chairman of the Southwest Power Pool, to the effect that an RTO must look externally, not just internally, for the ingredients of real resilience – stating that SPP's interconnection to ERCOT is "next to zilch", to the West it is "good but not great", and to the east the interconnections "has been almost academic, as opposed to real." FERC ought to study "much more about how can neighbors help neighbors. It's part of the deficiency of our national system, and it ought to be highlighted." Quoted in *Megawatt Daily*, *FERC Resiliency Effort Needs Broader Coordination Study: SPP Stakeholders*, at p. 4, Feb. 26, 2018.

[18] "PJM is actively evaluating how to incorporate resilience into the planning process, including discussions regarding (a) making sure that system changes done as part of the Regional Transmission Expansion Plan do not make the [Bulk Electric System} less resilient, (b) developing procedures to compare solution alternatives and ensure selection of the alternative that enhances resilience, and (c) developing resilience criteria where the system has vulnerabilities that require mitigation. . . .To be clear, RTO resilience planning not only includes traditional transmission planning, but also an enhanced role in guiding regional restoration planning efforts." PJM Comments, at p. 33.

[19] Individual utilities have an important role to play in ensuring resilience, as these utilities constitute the first line of defense against potential threats.

[20] Increasingly, RTOs utilize scenario planning in anticipation of possible developments 10 to 15 years (or more) in the future. Those needs may include differences in locations and rates of load growth, different locations and rates of renewable generation, and thermal generation retirements. These changes involve determining the long term needs for transmission expansions and upgrades in anticipation. *See*, *e.g., Joint Comments of the Electric Reliability Council of Texas, Inc. and the Public Utility Commission of Texas*, at p. 9. ("Comments of ERCOT and PUCT").

most critical element of ensuring system resilience. For example, as part of its scenario planning to correct reliability criteria violations, ERCOT develops a corrective action plan that "typically involves building new transmission facilities."[21] Planning for resilience should likewise incorporate transmission solutions. As stated by the PJM Interconnection, "System resilience should be a consideration in the evaluation of planning solution alternatives so that PJM can select solutions that enhance the resilience of the system and address other system needs. Furthermore, resilience vulnerabilities that are significant enough to warrant a transmission system enhancement designed specifically to mitigate the resilience vulnerability could be designed and integrated into the (Regional Transmission Expansion Plan]."[22]

In short, WIRES advocates for further action to ensure that planning processes exist that will directly address grid resilience. WIRES respectfully requests the Commission to do the following:

- First, the range and complexity of resilience issues argue for extending this Commission proceeding in order to consider generic enhancements to the RTO/ISO transmission planning processes established under the Commission's authority to ensure that strong and cost-effective grid infrastructure is a principal tool for anticipating and mitigating the risks and heavy costs that disruption of bulk power markets could impose on the health and economic welfare of the American public. In WIRES' view, grid resilience can only be ensured if regional and interregional transmission enhancements are part of the solution. The Commission should examine whether, in pursuit of a more resilient grid, it should require RTOs and ISOs to integrate (or demonstrate that they have integrated) resilience planning into their regional and interregional transmission planning processes. While planning for resilience necessarily entails coordination and facilities expansion across regions and between markets, each region should be afforded such flexibility as is needed to promote and enhance grid resilience in a manner that reflects the operating characteristics of that region, including the

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[21] *Id*., at p. 7. "When planning new transmission projects, ERCOT strives to build greater resilience into the system. This includes considering the geographic diversity of transmission lines serving a load center. . . . When appropriate, ERCOT has also conducted studies to determine the potential contingency impacts of placing a proposed line in a common right-of-way with one or more existing transmission lines." *Id*.at p. 8

[22] Comments of PJM, at p. 50

likelihood of particular adverse events or threats. However, as the above-cited RTO/ISO observations demonstrate, planning for adequate transmission investment is an accepted, valuable, and workable part of making any regional grid or any interregional systems more resilient.[23]

- Second, in order to make certain that RTOs and ISOs can effectively carry out any Commission planning directives that might come from this proceeding, FERC should first clarify that resilience is included in its existing statutory authority to promote reliable operation of the Bulk Electric System (BES). This is essential given the newness of resilience as a planning issue and the potential risks that uncertainty or ambiguity could create for RTOs/ISOs and Commission policy. Likewise, certainty in the administration of new policy must be provided by clarifying that the regional planning responsibilities of RTOs and ISOs also includes planning for resilience.

- Finally, the Commission should update its prescribed planning principles and criteria as they apply to resilience objectives through its rules or tariff requirements for regional grid operators and planners. That should entail updating its Order 890 transmission planning principles to include resilience as a planning driver.

CONCLUSION

WIRES anticipates that the Commission's focus on resilience can and should drive significant portions of its electric power policies. It also anticipates that, together with reliability issues, the economic benefits of a more integrated electric power system, the need to deploy and dispatch new technologies, the bulk power market's evolution, and public policy, transmission development will be driven by the need for greater resilience in the continuous delivery of electricity. In that sense, this proceeding can be part of a larger focus and initiative that prepares the grid for a more intensely electric and economically dynamic future. WIRES looks forward to further Commission deliberations on the role that transmission grid upgrades, modernization, and planned resilience will play in determining the future health and effectiveness of the North American economies.

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[23] Similar recommendations are made by the PJM Interconnection in response to several of the Commission's questions. PJM Comments at pp.32-34, 40-41, 48-52.

WIRES wishes to thank the Commission for initiating this proceeding and considering WIRES' Comments about the importance of transmission investment as a resilience strategy.

Respectfully submitted,

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APPENDIX

“RECOGNIZING THE ROLE OF TRANSMISSION IN ELECTRIC SYSTEM RESILIENCE”

The Brattle Group (May 9, 2018)

Recognizing the Role of Transmission in Electric System Resilience

PREPARED FOR

WIRES

PREPARED BY

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May 9, 2018

THE Brattle GROUP

This report was prepared for WIRES. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

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Executive Summary

Resilience of the electric power system is the ability of the nation's electricity infrastructure to prevent or diminish damage from high-impact, low-probability events without undue disruption and to rapidly restore service when such disruptions occur. The robustness and flexibility of the high-voltage transmission grid will be critical to the FERC's consideration of electric system resilience for two reasons that track the definition of resilience itself:

- First, the transmission grid can absorb the damage potentially arising from multiple local generator outages without customer service disruptions by providing access to a network of technologically diverse and geographically dispersed set of power supplies. When sufficiently robust to maintain the flow of power under stressful conditions, transmission systems are inherently resilient.
- Second, the transmission sector has been pursuing investments in both physical assets and operational changes that strengthen the ability of the regional and inter-regional transmission grid to keep operating when challenged by adverse events and to aid the rapid restoration of service when damage and customer outages do occur.

The Federal Energy Regulatory Commission (FERC) can recognize the central role of the transmission grid in promoting electric system resilience by: (1) continuing to support an array of investments to strengthen the transmission grid and (2) expanding the role of resilience in regional and inter-regional transmission planning to build upon and expand the inherent resilience benefits that the transmission grid already provides.

Transmission planning has thus far focused primarily on the distinguishable (and valid) need for reliability in the short run. Accounting for the "insurance value" of a more flexible and robust transmission grid in the long-run can protect consumers from costly disruption during severe adverse events that likely will happen without forewarning of their timing, location, and severity. Like any insurance policy, transmission-focused planning and investments could provide cost-effective solutions to address fuel security concerns in some regions without requiring a redesign or rethinking of the competitive generation markets that have produced substantial consumer benefits. Finally, the FERC should consider resilience in addition to the Order 1000 goals of reliability, economics, and public policy, as a planning objective for both regional and inter-regional transmission expansion to help insure against large-scale disruption of electricity supply. This would represent an important step forward in transmission planning analysis and improve overall electric system resilience.

I. Introduction

The business of generating, transmitting and delivering electric power has always involved a singular focus on "keeping the lights on" under all possible conditions, regardless of what labels – such as "reliability" or "resilience" – are used to describe the primary goal. Recently, concerns about the security and availability of generating fuels such as natural gas have been identified as potential threats to the resilience of the electricity system. This recent focus on generation has diverted attention from other key segments of the industry – particularly the high-voltage transmission grid – that traditionally have been and should continue to be a central focus of efforts to enhance resilience. This study explores the important role that transmission plays in grid resilience and how policies and investments directed at strengthening the transmission system can cost-effectively enhance the resilience of electricity supply.

In contrast to the well-developed and intensively-managed issue of electric service reliability, the understanding and analysis of electricity grid resilience is still developing. The concept of resilience focuses on how critical infrastructure manages through and, when necessary, recovers from high-impact, low-probability events such as severe weather or physical or cyber-attacks. For this report, we follow the widely-cited 2009 National Infrastructure Advisory Council (NAIC) definition of infrastructure resilience as:

> The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and or rapidly recover from a potentially disruptive event.[1]

This definition was expanded upon in a follow-up 2010 report, *A Framework for Establishing Critical Infrastructure Resilience Goals*, to include a resilience construct based on robustness, resourcefulness, rapid recovery, and adaptability as shown in Figure 1.

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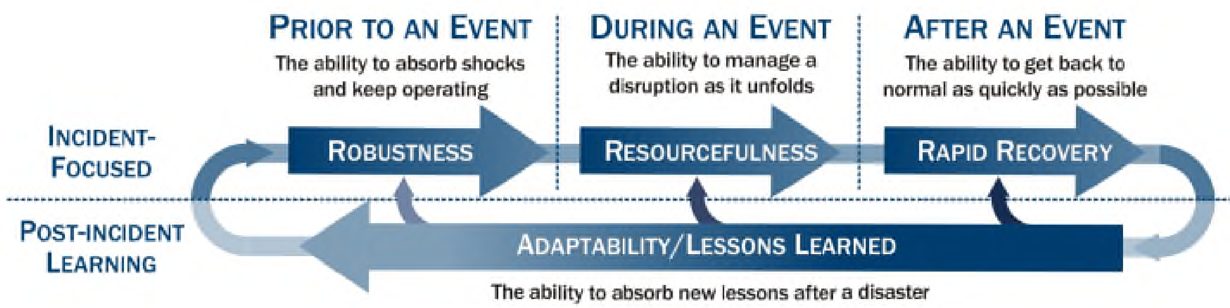
[1] National Infrastructure Advisory Council, *Critical Infrastructure Resilience: Final Report and Recommendations,* September 8, 2009, p. 17.

Figure 1: The Sequence of the NIAC Resilience Construct



Source: National Infrastructure Advisory Council, *A Framework for Establishing Critical Infrastructure Resilience Goals: Final Report and Recommendations by the Council,* October 19, 2010.

The evolution of the modern bulk power system, from municipal central stations serving local customers to large regional and interregional networks connecting distant resources to growing loads, has been driven by the inextricably linked goals of resilience, reliability, and economics. Increasing the geographic size or "footprint" of the bulk power system through transmission interconnection allows customers to capitalize on economies of scale and scope in energy, capacity, and reserves. As far back as the 1965 blackout that affected 30 million customers in the eastern United States and Canada, the recommendation has been to move toward more connected systems. The official report on the 1965 blackout states, "Isolated systems are not well adapted to modern needs either for purposes of economy or service" and recommended "… an acceleration of the present trend toward *stronger transmission networks within each system and stronger interconnections between systems* in order to achieve more reliable service at the lowest possible cost."[2]

As the connection between bulk power generation and the local distribution system to serve retail customers, the transmission system is critical to the overall performance of the power sector and its resilience when challenged by infrequent but significantly adverse events. Strengthening the resilience of individual generators or the generation fleet overall will not increase the overall resilience of the system if the power cannot be delivered into an intact distribution system to serve customer loads. This applies within a recognized transmission region within Regional Transmission Organizations (RTOs) and between regions. Within regions, the

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2 Federal Power Commission, "Report to the President on the Power Failure in the Northeastern United States and the Province of Ontario on November 9-10, 1965," December 6, 1965. p. 43 (emphasis added).

transmission network connects a diverse set of generators to distribution systems that serve customers. Inter-regionally, the transmission network connects neighboring systems to increase overall reliability and resilience by providing access to additional generation resources to increase benefits of trading across regions and for providing resources during emergency situations. Finally, transmission has been recognized as critical infrastructure since the resilience concept was defined, and therefore policies and investments to strengthen the transmission system have been central to the electricity industry's overall effort to promote and enhance resilience.[3]

This report highlights how existing transmission contributes to power system resilience and describes how evolving policies and new investments in transmission will further enhance power system resilience. In the next section, we explain how the transmission system helps maintain or restore power in cases where multiple simultaneous generation failures might threaten customer disruptions. We follow this with a discussion of how policies and investments in the transmission system mitigate vulnerabilities of the transmission system to high-impact low-probability events that can compromise resilience, and then we conclude by discussing how transmission owners and operators anticipate future resilience challenges through preparation and planning.

II. The Transmission Network Enables Bulk-System Resilience

The power system can be vulnerable to disruptions originating at multiple levels, including events where a significant number of generating units experience unexpected outages. The transmission system provides an effective bulwark against threats to the generation fleet through the diversification of resources and multiple pathways for power to flow to distribution systems and ultimately customers. By providing customers access to generation resources with diverse geography, technology, and fuel sources, the transmission network buffers customers against extreme weather events that affect a specific geographic location or some external phenomenon (unavailability of fuel and physical or cyber-attacks) that affect only a portion of the generating units. In addition to other economic and reliability benefits, these resilience benefits occur both within and between regions.

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3 See, for example, *Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons,* U.S. Department of Energy, August 2010.

On a regional basis, transmission networks provide customers with access to a variety of generators, where resource and fuel diversity decreases the vulnerability to common mode failures and promotes resilience. For example, the transmission networks provide Southern California customers access to hydropower from the Pacific Northwest, nuclear energy from Arizona, solar and wind power from neighboring states, and natural gas generation from neighboring states. As a result of this diversity, customers did not experience interruption when the 2.2 GW San Onofre nuclear power plant unexpectedly shut down in 2012 and then officially retired in 2013. Likewise, southern California customers did not experience outages from the 2011-2016 drought, which affected the state's entire hydropower fleet,[4] or the 2015 Aliso Canyon gas leak, which affected natural gas availability for a whole fleet of generating plants in southern California. While the fuel diversity among generators may exist over geographic regions, customers only benefit from such diversity when these resources are interconnected through the transmission network.

The broad geographic scope of the transmission system provides resilience to the system. For example, severe or extreme weather events typically affect only a portion of the region served by the wider grid. During and following such an event, customers in the affected regions are able to draw power from unaffected generating plants through the regional transmission system. For example, during a cold snap in January 2018 that significantly affected MISO South, power flows from MISO into MISO South (parts of Arkansas, Louisiana, Mississippi and Texas) briefly exceeded the contractual regional directional transfer (RDT) limit, enabling MISO South to avoid load shedding. By drawing power from the rest of MISO, the southern region maintained power delivery during a period of record demand and significant generator outages.[5]

The diversity of the resources interconnected through the transmission network also provides robustness to cyber or physical attacks waged against a specific generator type, fuel source, or utility service area. From a reliability perspective, the bulk power system is designed to withstand outages, and a certain level of unexpected generator outages are part of standard

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4 According to the California Department of Water Resources, this included four of the driest consecutive years on record, 2012-2014. California Department of Water Resources, "Water Year 2017: What a Difference a Year Makes," September, 2017. p.2

5 See "Exceeding transmission limits prevented MISO South blackouts in Jan: IMM" by Mark Watson, *MW Daily*, March 27, 2018.

operating and planning procedures within the power system. From a resilience perspective, should multiple units within a region or a type of generating station across regions become unavailable to supply power, operators will be able to draw from other, unaffected and available resources to the extent enabled by the transmission network.[6]

If an adverse event overwhelms the regional ability to absorb or manage the event, inter-regional transmission connections allow regional operators to "lean" on neighbors for emergency support. Thus, in cases where generation outages in one region threaten reliability, interties with neighboring regions can substitute for the inadequate generating capacity within that region. The weaknesses associated with lack of inter-regional transmission were vividly on display during the 1965 Northeast Blackout, which affected more than 80,000 square miles and 30 million customers across the United States and Canada with most outages lasting several hours.[7] Recognition that stronger interregional transmission links could have prevented these outages led to the expansion of the transmission grid into the large regional networks we rely on today.

The reliability benefit of such regional and interregional transmission network has not changed since. A 2013 study that Brattle and Astrape Consulting conducted for FERC found that interties offer substantial benefits from both a physical reliability and economic perspective:

> Strong interties with neighboring regions provide both economic and physical reliability value during peaking conditions. Load and generation diversity mean that the most extreme scarcity conditions are unlikely to occur at the same time in neighboring markets.[8]

As the quote above implies, when regional resource adequacy is threatened because of a lack of generation diversity, then interties with neighboring systems with a different fuel and technology mix (one less affected by the conditions adversely affecting specific regional

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6 This does not negate the potential for events for which insufficient power is capable of importing into the region or regions with units unexpectedly out of service.

7 A tripped relay in Ontario caused the outage, which then cascaded through New York and New England; all service was restored within 14 hours. Additional interregional transmission capacity could have mitigated the outage. See Federal Power Commission, "Report to the President on the Power Failure in the Northeastern United States and the Province of Ontario on November 9-10, 1965," December 6, 1965.

8 See Johannes P. Pfeifenberger, Kathleen Spees (Brattle) and Kevin Carden, Nick Wintermantel (Astrape) *Resource Adequacy Requirements: Reliability and Economic Implications,* September 2013, p. 57, found at https://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf.

resources) can provide a cost-effective alternative to retaining or building new resources to address generation diversity or overreliance on a particular fuel. One of the steps taken by PJM during the Polar Vortex episode in the Eastern U.S. in January 2014 was to access energy and reserves from adjacent regions on an emergency basis, which helped manage shortages within the RTO.[9] The potential value of creating resource diversity through inter-regional interconnection is well illustrated by ISO New England's analysis of diminishing its heavy reliance on natural gas combined with natural gas delivery constraints.[10] One option studied to address the current lack of fuel diversity in New England is the expansion of interregional transmission from New York, Quebec, and New Brunswick designed in part to access more hydro and other renewable generation facilities located in Canada.[11]

The ability for transmission systems to increase reliability and resilience of regional or inter-regional power systems is dependent upon the strength of interconnections. This strength depends both on the number of lines and the capacity of those transmission lines. In its comment to FERC, PJM noted that transmission designs that are "robust and electrically dense" (compared with sparse networks) provide resilience benefits.[12] A dense network with many interconnections is more resilient as power can flow over many parallel routes. The ability for that power to flow, however, is dependent upon having sufficient capacity. Thus, to realize resilience benefits, the transmission network must be able to provide capacity beyond the normal day-to-day level, and perhaps even beyond the anticipated stress scenario utilization of the facilities.[13] Transmission planning should take into account the potential resilience value of investments when considering expansion projects.

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9 See *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events,* PJM Interconnection, May 8, 2014, p. 19-20.

10 See for example, ISO New England, "Operational Fuel-Security Analysis," January 17, 2018.

11 Ibid.

12 *Comments and Responses of PJM Interconnection, L.L.C.*, Docket No. AD18-7-000, March 9, 2018, p. 43.

13 Transmission lines are typically rated for both "normal" and "emergency" operation, with the "emergency" rating available for short time periods of overloading. For the transmission system to accommodate unanticipated and potentially large flows for a sustained period, the headroom created through emergency ratings may be insufficient.

III. Transmission System Investments Improve Electricity System Reliability and Resilience

Although recent concern surrounding electric system resilience has focused on fuel security and resource adequacy, inadequate generation almost never results in customer outages. Instead, the vast majority of customer outages occur from damage to distribution systems caused by such events as severe storms. According to the Quadrennial Energy Review:

> Failures on the distribution system are typically responsible for more than 90 percent of electric power interruptions, both in terms of the duration and frequency of outages. Damage to the transmission system, while infrequent, can result in more widespread major power outages that affect large numbers of customers and large total loads.[14]

Because the transmission system has been designed to withstand contingencies and adverse conditions, the transmission network routinely experiences severe weather events without causing customer outages. When the robustness of the transmission infrastructure is overwhelmed, however, sustained and widespread customer outages can occur, for example when extreme weather topples transmission towers across a wide region or operators are unable to manage grid instability arising from faults or outages. Due to their broad impact, these rare events are extensively studied *ex post* to advance understanding of vulnerabilities and explore and adopt measures to reduce future impacts. As a result, much of the analysis of resilience in the bulk power system focuses on high-impact, low probability events that directly affect transmission, which has supported some policy reforms and investments to address transmission resilience issues. Nevertheless, much more can be achieved, and we discuss the evolving policies and investments relating to transmission planning, physical infrastructure development and operations below, using the four NIAC resilience elements – robustness, resourcefulness, rapid recovery, and adaptability – as a framework to describe their overall role in responding to a resilience threat or event.[15]

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14 U.S. Department of Energy, *Transforming the Nation's Electricity Sector: The Second Installment of the QER,* January 2017, Chapter 4 "Ensuring Electricity System Reliability, Security and Resilience" p. 4-29.

15 It should be noted that transmission and distribution facilities share some failure modes, particularly extreme weather damage. Because distribution facilities are more vulnerable to storm damage, some of the programs that we highlight below primarily focus on distribution infrastructure; however,

Continued on next page

A. DEVELOPING A MORE ROBUST TRANSMISSION NETWORK

The robustness of the transmission network, its ability to absorb shocks and continue functioning, continues to be enhanced by the hardening of existing infrastructure and increasing connectivity within and between regions. Hardening the current infrastructure makes it less vulnerable to equipment failure as a result of major events, such as severe weather or human attack. This hardening of the existing infrastructure can include upgrading the physical strength of existing infrastructure (e.g., storm resilience), relocation of assets to less vulnerable locations, increasing transmission system capacity and connectivity, adding physical or cyber security, and improving operational practices.

Storm damage to the transmission network frequently results in reinvestment into more robust infrastructure. While not nearly as vulnerable to storm damage as local distribution systems, the transmission network has suffered damage from especially severe weather events, such as the catastrophic ice storm that hit New England and Eastern Canada in 1998. That storm resulted in the collapse of 770 transmission towers,[16] and in eastern Maine, a damaged switch affected about 40% of Eastern Maine Electric Coop's customers for nine hours.[17] Overall, the transmission damage which, combined with extensive damage to distribution systems, caused outages affecting hundreds of thousands of customers for three weeks or more. Hurricane Katrina in 2005 destroyed 1,515 transmission structures and forced 300 substations offline.[18] Likewise, Superstorm Sandy affected over 200 transmission lines across the northeast and mid-Atlantic.[19]

Continued from previous page

storms can damage high voltage power lines and substations through flooding, high winds, ice accumulation and other modes that can and do affect both transmission and distribution elements.

16 National Academies of Sciences, Engineering and Medicine, 2017, *Enhancing the Resilience of the Nation's Electricity System*, p. 13.

17 Jones, Kathleen and Nathan Mulherin, U.S. Army Corps of Engineers, *An Evaluation of the Severity of the January 1998 Ice Storm in Northern New England: Report for FEMA Region 1*, April 1998.

18 These events are described in National Academies of Sciences, Engineering and Medicine, 2017, *Enhancing the Resilience of the Nation's Electricity System*, p. 13. It should be noted that when severe weather damages both transmission and distribution systems, attributing the length of customer outages to restoring transmission or distribution may not provide an accurate appraisal of the relative impacts for specific cases.

19 Office of Electricity Delivery and Energy Reliability U.S. Department of Energy, *Comparing the Impacts of Northeast Hurricanes on Energy Infrastructure*, April 2013.

After the 2004-2005 hurricane season in Florida, the state legislature ordered the Public Service Commission to "conduct a review to determine what should be done to enhance the reliability of Florida's transmission and distribution grids during extreme weather events, including the strengthening of distribution and transmission facilities." The resulting program included inspection, forensic analysis of failed transmission structures and a schedule for upgrading and replacing vulnerable equipment.[20]

In response to physical attacks, utilities have added physical security measures following the creation of the NERC Critical Infrastructure Protection (CIP) standards. In April 2013, PG&E's Metcalf Transmission Substation was targeted by gunman, resulting in the damaging of 17 transformers. Former FERC Chairman Jon Wellinghof referred to the attack as "the most significant incident of domestic terrorism involving the grid that has ever occurred."[21] The attack caused more than $15 million in damage and took nearly a month to repair, but did not result in service disruption to customers due to the resilience of the local transmission and distribution system.[22] In Nogales, Arizona, a failed attempt to detonate an explosion at a peaking plant by igniting the diesel fuel tank in June 2014 would have affected 30,000 customers if the attack had damaged the adjacent substation. As a large infrastructure system with thousands of exposed assets, including substations and transmission lines, individual assets are vulnerable to physical attack,[23] and the CIP standards, authorized under FERC Order 802, were put in place following the Metcalf substation attack. These standards require utilities to identify and protect

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20 Florida Public Service Commission, *Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather*, July 2007.

21 Smith, Rebecca, "Assault on California Power Station Raises Alarm on Potential for Terrorism," Wall Street Journal. Published February 4, 2014.

22 Barker, David, "FBI: Attack on PG&E South Bay Substation wasn't Terrorism," SF Gate. Published September 11, 2014.

23 In addition to the incidents discussed here, transmission insulators are frequent targets for vandalism, and transmission lines may be targeted for protest. For example, in the 1970s, protesting against a new transmission line in Minnesota, a group called the Bolt Weevils shot out over 5,000 insulators and destroyed 8 transmission towers.

Minnesota Historical Society, Minnesota Powerline Construction Oral History Project, Ed Schrom narrator and Edward P. Nelson interviewer, 1981.

key assets.[24] As physical threats to the system increase and new assets are identified as critical to system operation, transmission owners will continue to enhance physical security.

The robustness of the transmission system also has been enhanced by increasing the connectivity of the network and the transfer capabilities on those connections. When unanticipated failures do occur on the network, increased connectivity can help diminish the impact on the system and may lessen the importance of any single element failure. Essentially, operators can re-route power in response to economic, reliability, or resilience events. The 1965 blackout was an illustration of the lack of interconnectivity, but following the blackout, the transmission capacity was increased within and between New England, New York, and the mid-Atlantic regions, greatly improving the power system's reliability and resilience.

Nationally and across regional networks, transmission system regulators and operators have responded to resilience challenges by improving operational practices and creating standardization and information sharing protocols. In reaction to the 1965 blackout, NERC was created and initially established voluntary protocols. Forty years later in 2005, NERC guidelines and protocols that set forth common reliability metrics, definitions, and requirements became mandatory, in part as a response to the operational failings that precipitated the blackout that affected the U.S. Northeast/Midwest and Canada on August 14, 2003.

A December 2015 cyber-attack in Ukraine that resulted in service interruptions to 225,000 customers clearly demonstrated the potential impact of a cyber-attack on the transmission and distribution sectors. These attacks disconnected seven 110 kV substations and twenty-three 35 kV substations for three hours through disruption of the Supervisory Control and Data Acquisition System (SCADA). While focused mostly on a local transmission and distribution system assets, the event highlighted the potential vulnerability of regional power system networks to malicious cyber intrusion. In March 2018, the Department of Homeland Security issued an alert outlining how Russian government cyber actors were actively targeting U.S. energy and other critical

24 These key assets are those that, "if rendered inoperable or damaged as a result of a physical attack, could result in instability, uncontrolled separation, or cascading within an interconnection." NERC Standard CIP-014-2. p.1

infrastructure sectors.[25] Although cyber-attacks against U.S. utilities have not yet caused sustained reported damage, the vulnerability is widely acknowledged and the industry has been actively sharing information and establishing protocols to harden against such an attack for nearly two decades. As far back as 2000, NERC established the Electricity Information Sharing and Analysis Center (E-ISAC) to share information on potential vulnerabilities, and in 2018 the Department of Energy (DOE) launched its own Office of Cybersecurity, Energy Security, and Emergency Response to prepare for and respond to cyber-attack, physical attacks, and storm damage.

B. Ameliorating Damage Arising From an Event

Investments in sensing equipment and control operations can allow transmissions system operators to react more quickly and effectively to system disturbance by isolating the damage and re-routing power to non-damaged areas. Re-routing power and isolating damaged areas relies on operators having access to up-to-date information on component status and access to tools and technology to re-route power flows without causing more problems. Ongoing investments in sensing equipment and potential investments in technologies that allow operators greater control of flows increase the ability of operators to manage an event as it unfolds.

Operator responses to transmission events can be prophylactic, adapting the system to accommodate a particular asset approaching failure, or responsive to an event, such as a physical attack, on the grid. Whether anticipatory or responsive, transmission owners have installed additional sensing equipment to the transmission system to provide system operators with accurate real-time system status information. For example, during hurricanes in Florida, operators were unaware in real-time of flooding in substations. Without this knowledge, operators were unable to triage the situation by removing the substations from service. In response to the outages caused by damaged substations, Florida Power and Light installed real-time water monitors at 223 substations to allow the company to proactively shut-down substations to limit and mitigate damage.[26]

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25 See U.S. Computer Emergency Readiness Team (US-CERT) Alert TA 18-074A, "Russian Government Cyber Activity Targeting Energy and Other Critical Infrastructure Sectors" found at https://www.us-cert.gov/ncas/alerts/TA18-074A.

26 This type of investment also enhances rapid recovery by avoiding repair or replacement needs.

Continued on next page

During the 2003 Northeast/Midwest U.S. blackout, operators did not have access to accurate information on the wider-system status, which could have helped limit the blackout's reach. The 2003 blackout was, at a high level, caused by transmission line outage in combination with operator errors. The initiating event for the blackout was a transmission line that was heated up through heavy usage, sagged, came into contact with vegetation, and then tripped offline. When that transmission line tripped offline, power flowed through alternative routes, overloading those lines, and causing cascading failures before operators were able to understand and react to the event. While the power system is planned to withstand the loss of one or several major elements, operators were initially unaware of the system outages and then failed to communicate with neighboring systems. The cascading blackout resulted in the loss of power to over 50 million customers in Canada and the United States, and the outage lasted for up to four days in some areas.[27] The economic cost of this event has been estimated between $4 billion and $10 billion.[28] In response to the need to understand and communicate operational status, over 800 phase measurement units (PMUs) that provide real-time system-status data were installed, and this data is shared within and across regions.[29] The measurements from these devices could have allowed operators to isolate the transmission failure and prevent the wide-area outages in the 2003 blackout.

New technologies and tools have the potential to allow transmission operators greater control over the flows on the network and proactively manage events. One of the central challenges to operating the transmission system is that flows on individual transmission lines are largely dictated by physics rather than a system operator's preferences or needs. The ability to actively control power flows would allow an operator to avoid, for example, overloading certain lines that may result in cascading failures. Technologies such as Flexible AC Transmission System (FACTS)

Continued from previous page

Florida Power and Light, "FPL expects approximately 4.1 million customers may lose power at some point as a result of Hurricane Irma." News release published September 8, 2017.

27 U.S.- Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* April 2004. p. 1

28 National Academies of Sciences, Engineering, and Medicine. *Enhancing the Resilience of the Nation's Electricity System*. Washington, DC: The National Academies Press. 2017. p.13

29 North American SynchroPhaser Initiative, *PMUs and synchrophasor data flows in North America as of March 19, 2014,* No date.

devices and "topology control" can enhance a system operator's availability to respond to events, as well as increase the efficiency of unit dispatch.[30] Investment in FACTS devices have the potential to allow operators to change flows by modifying transmission line properties through power electronics. Likewise, transmission switching, which is actively used by ISO/RTOs, allows operators to re-route flows by disconnecting and reconnecting lines; however, this is usually executed on longer timescales (*e.g.*, seasonal). Several RTOs have analyzed new approaches that would allow topology control on operational timescales.

C. Recovering Quickly to Restore Service After an Event

Rapid recovery following a transmission event requires the inspection, replacement or repair of damaged transmission system components. These actions can require specialized workforces and components that can be expensive for individual utilities to maintain or replace; specialized workforce personnel might include helicopter pilots, and required components may include multi-million dollar assets such as large transformers. In response, utilities have been expanding sharing agreements to improve restoration time through increased access to components and workforces.

The most visible recovery initiatives in the power sector are utility mutual assistance programs, which dispatch lineman and other skilled workers to respond to large-scale events; these programs have reacted to major resilience events through a focus on nation-wide events and reorganization for improved efficiency. Electric companies organize into voluntary Regional Mutual Assistance Groups (RMAGs) and respond to regional and national events that affect multiple regions. For example, during the 2012 derecho that caused more than four million customers to lose power across the mid-Atlantic and Ohio, crews came from as far as Canada, Texas, and Wyoming to restore power,[31] and restoration following Superstorm Sandy involved crews from all RMAGs.[32] The scale of the response required for Superstorm Sandy revealed weaknesses in the organization for national-scale responses, and as a result, three RMAGs in New England consolidated into a single entity and the Edison Electric Institute (EEI) members

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30 Topology control refers to the re-routing of power by adding and remove transmission lines from service.

31 Edison Electric Institute, *Understanding the Electric Power Industry's Response and Restoration Process*, No date. p. 4

32 Ibid. p. 5

developed a framework to coordinate national responses.[33] EEI runs storm drills to prepare utilities for the nation-wide events as well table-top drills with federal organizations.[34] The scale and duration of these events qualify as tests to resilience, and although they involved damage to both distribution and transmission system elements, the repair to the transmission system was a necessary part of the restoration process.

In addition to personnel, utilities maintain spare components and form pools to maintain spare components that are too expensive or difficult to obtain for restoration purposes. There are currently industry-led sharing programs, including NERC's Spare Equipment Database, Edison Electric's Spare Transformer Equipment Program (STEP), SpareConnect, Grid Assurance, Wattstock, and the Regional Equipment Sharing for Transmission Outage Restoration (RESTORE) group. The RESTORE group, for example, includes 28 utilities that agree to sell equipment to other members following a triggering event.[35] Several of these groups arose from vulnerabilities associated with the availability of Large Power Transformers (LPTs), which have limited domestic production capabilities, long lead times, and cost millions of dollars each. Utilities also maintain stockyards with spare conductors, towers, and related equipment for restoration purposes.

D. Learning Resilience Lessons

Because transmission resilience events have the potential to affect a broad geography, the events are closely studied and frequently result in changes to the system and system operations. That is, lessons learned provide the basis for improvements that reduce the impact of similar future events. These studies of transmission-related events mark the importance of the event and range from storm reports required by state governments to reports by the Federal Emergency Management Agency (FEMA), NERC, DOE, and others. As discussed in the sections above, these reports have resulted in actions including transmission line hardening, increased sharing of threat information, changes in reliability planning and system design standards, and improvements to wide-area sensing.

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33 Fishbach, Amy, "Tactical Tips for Utility Mutual Assistance," T&D World. Published August 30, 2017.

34 Ibid.

35 Peter Maloney, "28 utilities join RESTORE program to boost grid resilience, reliability," Utility Dive, October 4, 2017.

IV. Anticipating Resilience Challenges

The ongoing policy reforms and investments in the transmission sector largely reflect an adaptive response to major events and disturbances. However, the industry also proactively plans for unprecedented events that could plausibly threaten grid resilience. We highlight two of these activities below: war-game type response simulations and enhanced transmission planning.

A. Operational Response Exercises

As mentioned above, cyber-attacks in the U.S. have not yet disabled a significant transmission component or system, but the industry intensively prepares for that threat. In addition to the information sharing discussed previously, utilities practice responding to physical and cyber-threats through national simulations. NERC organizes biennial exercises, called GridEx, that allow utilities, law enforcement, federal agencies, and other operators of critical infrastructure systems to test and improve protocols in case of attack. The GridEx exercises include two day simulations for utilities and their partners as well as a one day executive-level tabletop game. Thus far, NERC has executed four GridEx events with 2017's GridEx IV drawing participation from over 450 entities, including water utilities, oil and natural gas companies, and telecommunication utilities.[36] The executive tabletop game in 2017 included participants from the White House National Security Council, DOE, the Department of Homeland Security, FEMA, the Department of Defense, the Federal Bureau of Investigation, the state of Maryland, the state of Virginia, and the National Guard in Illinois and Wisconsin.[37]

The GridEx simulations result in recommendations for policies, procedures, and investments within the power sector to increase readiness, including recommendations for regional and national programs and tools. During GridEx III, the need for cyber mutual assistance, analogous to the RMAGs for physical infrastructure, was highlighted. In response, a Cyber Mutual Assistance (CMA) program was developed that provides a pool of cyber security experts that are able to assist during an event, and the CMA program now includes more than 140 organizations, including natural gas and electric utilities, regional transmission operators, and independent

36 NERC, *Grid Security Exercise GridEx IV: Lessons Learned*, March 2018. p. 1

37 *Ibid.* p.2

system operators across the United States and Canada.[38] Likewise, GridEx IV identified the need for alternative communications when actors were unable to communicate effectively due to a simulated communications blackout and produced a recommendation to establish contingency plans and make use of existing federal communication programs.[39]

B. TRANSMISSION PLANNING

The goals for transmission planning arising from FERC Order 1000 are sometimes listed as reliability, economics and public policy; so-called "multi-value projects" serve these needs by enhancing reliability, increasing market efficiency and supporting public policies. It is reasonable to ask how "resilience" might fit into this framework, although that is not straightforward to answer. Resilience is related to reliability, but broader. It is a public policy goal, but other public policy goals, such as support for clean energy, may also be considered. Resilience is an economic issue in the same way that insurance and disaster preparedness has an economic dimension. In other words, resilience can involve all three Order 1000 objectives while remaining distinct in some ways. The Venn diagram below in Figure 2 shows the relationship between resilience and other transmission planning objectives, where resilience encompasses the entire area where economics, reliability and public policy intersect. This representation suggests that transmission planning that appropriately values economics, reliability and public policy objectives will also further resilience goals, and that considering resilience will enhance the benefits attributed to multi-value projects. It also suggests that stand-alone "resilience projects" could warrant consideration in planning processes, although that possibility remains unlikely in the current environment. Regardless of the degree of potential overlap between resilience and the other goals, however, a valuation of potential resilience benefits should help inform a more comprehensive analysis of the benefits of transmission projects.

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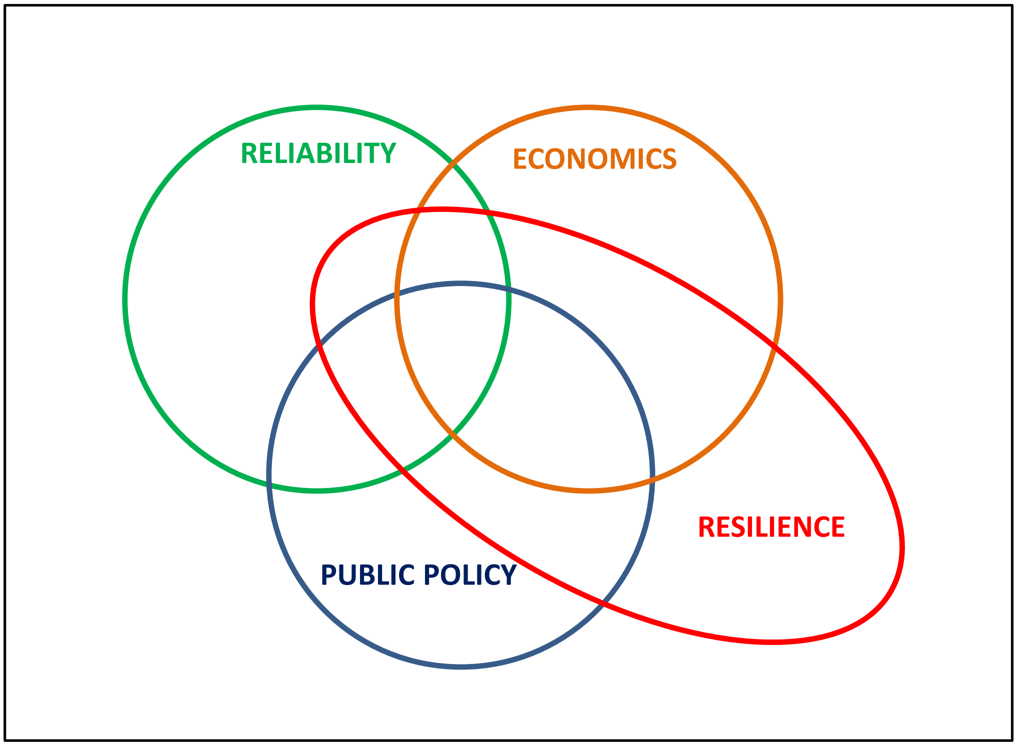
38 Electricity Subsector Coordinating Council, *The ESCC's Cyber Mutual Assistance Program,* January 2018.

39 NERC, *Grid Security Exercise GridEx IV: Lessons Learned*, March 2018. p. 15

Figure 2: The Relationship between Transmission Planning Objectives



Reliability planning for the transmission system already incorporates some high-impact, low-probability events, such as single or multiple large contingencies during 90th percentile peak load conditions, or simultaneous outages of the largest transmission and generation facilities during summer heat waves. To further incorporate potential resilience considerations, more extreme conditions could be evaluated, such as situations where a significant portion of the generating fleet becomes unavailable for an extended period of time, when assessing the expected benefits of constructing and sizing of a proposed transmission line.

Such assessments of low-probability, high-impact events are sometimes included in the economic assessment of transmission investments. For example, in a 2015 study, The Brattle Group recommended that "anticipatory" transmission planning also assess the economic benefits that might arise in unlikely but extremely adverse scenarios, in order to fully capture the insurance value of transmission.[40] The Brattle study examined the 2004 analysis of a second Palo Verde to

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[40] Johannes Pfeifenberger, Judy Chang, and Akarsh Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid*, The Brattle Group, April 2015. See also Johannes Pfeifenberger and Judy Chang, *Well Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the*

Continued on next page

Devers line (PVD2) that would enable imports from Arizona into California. One high-impact, low-probability event considered was a long-term outage at the San Onofre nuclear plant—an outcome that actually occurred in 2012. While the case study focused on the economic benefits from lower-cost replacement power enabled by the PVD2 line, comparable reliability and resilience benefits would arise if other conditions impaired generation availability elsewhere in California.

Both economic and reliability benefits are highly correlated with resilience benefits, although these benefits (e.g., protection against high costs and possible service disruptions) are typically quantified in the context of analyzing a less extreme range of adverse conditions or scenarios. Quantifying the expected benefit of transmission under more severe disruptions will augment the overall benefits from transmission investment. Because additional transmission capacity can enhance the overall level of reliability and resilience of the bulk power system, planning should increasingly assess the potential resiliency benefit of adding transmission within and between RTOs and other market areas. A 2013 Brattle Group report for WIRES found that estimating the benefits of mitigating the impacts of extreme events and system contingencies was crucial to a comprehensive analysis of transmission benefits:

> Transmission upgrades can provide insurance against extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages. Even if a range of typical generation and transmission outage scenarios are simulated during analyses of proposed projects, production cost simulations will not capture the impacts of extreme events; nor will they capture how proposed transmission investments can mitigate the potentially high costs resulting from these events. Although extreme events occur very infrequently, when they do they can significantly reduce the reliability of the system, induce load shed events, and impose high emergency power costs. Production cost savings from having a more robust transmission system under these circumstances include the reduction of high-cost generation and emergency procurements necessary to support the system. Additional economic value (discussed further below) includes the value of avoided load shed events.
>
> The insurance value of additional transmission in reducing the impact of extreme events can be significant, despite the relatively low likelihood of occurrence.

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Transition to a Carbon-Constrained Future, The Brattle Group, June 2016, pp 6-11 for a synopsis of studies that address the economic benefits of transmission, including under severe adverse conditions.

> While the value of increased system flexibility during extreme contingencies is difficult to estimate, system operators intrinsically know that increased system flexibility provides significant value. One approach to estimate these additional values is to use extreme historical market conditions and calculate the probability-weighted production cost benefits through simulations of the selected extreme events. For example, a production cost simulation analysis of the insurance benefits for the Paddock-Rockdale 345 kV transmission project in Wisconsin found that the project's probability-weighted savings from reducing the production and power purchase costs during a number of simulated extreme events (such as multiple transmission or nuclear plant outages similar to actual events that occurred in prior years) added as much as $28 million to the production cost savings, offsetting 20% of total project costs.[41]

Transmission planning should incorporate resilience considerations. In addition, transmission options should be considered to address resilience concerns such as regional resource shortage or fuel diversity/security issues. Secure electricity imports enabled by expanded transmission may provide cost-effective resilience benefits even in cases where generation fuel security is identified as the proximate resilience threat. Analysis of interregional transmission proposals could also incorporate the potential to avoid or mitigate damage from high-impact, low-probability events that pose resilience threats.[42] Because resilience is a systemic issue, the design of public policy to enhance resilience should look broadly at potential solutions.

V. Conclusion

Transmission has occupied a central role in the discussion of critical infrastructure resilience since that discussion began over a decade ago, and it continues to play an important role in the current resilience debate because:

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41 See Judy Chang, Johannes Pfeifenberger, J. Michael Hagerty, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, Prepared by The Brattle Group for WIRES, July 2013, p. 39; for additional detail on the Paddock-Rockdale analysis see American Transmission Company LLC, Planning Analysis of the Paddock-Rockdale Project, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference #75598) pp. 50-53.

42 Of course, interregional transmission planning faces unique challenges. See Johannes Pfeifenberger, Judy Chang, and Akarsh Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of An Insufficiently Flexible Electricity Grid*, April 2015, pp. 25-37.

- Transmission can *enable* or *enhance* resilience, for example, when power from neighboring regions can flow to a region beset by outages of available generation (e.g., multiple outages associated with a particular fuel or technology);
- The transmission sector has *invested steadily* in enhanced reliability and resilience owing to rare but significant, widespread customer outages that can occur when transmission systems suffer physical damage or operations fail to avoid or contain delivery outages; and
- *Additional investments* in transmission expansion, innovative technology and operational controls can enhance grid resilience cost-effectively in the face of emerging threats.

The current focus on increasing the resilience of generation fleets in certain regions should not obscure or divert attention from the importance of the transmission grid to the overall resilience of the power system. Even as the generation fleet faces new and intensified challenges, the transmission system is needed to deliver the generated power to the distribution system and retail customers. Because the critical role of transmission to system reliability and resilience has long been recognized, continuous improvements have made the transmission more resilient over the past decades. Continuing attention and focus on transmission operation and investments will be necessary to identify and address existing and new threats to power system reliability and resilience.

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APPENDIX B

A WIRES Report

The Truth about the Need for Electric Transmission Investment: Sixteen Myths Debunked

London Economics International LLC

Julia Frayer

Eva Wang

Marie Fagan

Barbara Porto

Jinglin Duan

WIRES

www.WIRESgroup.com

SEPTEMBER 2017

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WIRES' PREFACE

WIRES[1] presents this excellent white paper by **London Economics International (LEI)** in response to many myths and long-held beliefs about investment in electric transmission that influence the thinking or actual decisions of policy makers, regulators, and the public about the need for, and benefits of, this critical infrastructure. For example, many people believe that lower demand for electricity means that the electric transmission system does not need to be upgraded or expanded. Others are persuaded that fixes or improvements to a facility or system in another service territory, state or region do not benefit them and are properly someone else's responsibility.

In reality, all North American economies will become more dependent on electricity as communications, banking, transportation, heating, automated manufacturing, and other developments drive our future economy and life styles and increase the need for electricity. The reliability and resilience of the electric system will consequently become more critical to us all. Despite this prospect, WIRES contends that regulators, public policy makers, industry, and the public, which stands to benefit from a robust grid, often bring outdated assumptions, misconceptions, and fallacies into their decisions about transmission investments.

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[1] WIRES is an international non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. WIRES members include integrated utilities, regional transmission organizations, independent and renewable energy developers, and engineering, environmental, and policy consultants. WIRES' principles and other information are available on its website: www.wiresgroup.com.

Yet, the truths about why we need to invest in the grid are not always self-evident. Therefore, WIRES has asked LEI to take a fresh look at the most fundamental misconceptions about transmission investment. These "myths" can often inflict a significant cost on investors in transmission and on customers because they contribute to protracted project delays and discount the importance of the flexibility and resilience that a robust grid provides. It is important to confront the myths that LEI identifies because they can frustrate even the most beneficial infrastructure projects. Modernization of the transmission grid that has been inherited from the last century will create an increasingly integrated and technology-driven network that binds regional power markets together and widely delivers economic, reliability, and environmental benefits. It should be accompanied by recognition that changes are needed to the regulatory system in which transmission planning and public interest determinations continue to be made under uncoordinated state and federal regulatory regimes. Those decision making processes may also require modernization.

In this paper, the LEI analysts identify the most pervasive and problematic myths from a policy-making point of view. They rebut those misconceptions and document why those myths are outdated, fallacious, or have no basis in fact. The paper then provides case studies that demonstrate why these myths about transmission investment are not supportable.

Myths can be very difficult to identify as such because they often contain an element of truth or fact. WIRES does not minimize the difficulties associated with siting major transmission infrastructure or the need for assurance that these investments will bring commensurate benefits to local, state, or regional economies and consumers of electricity. However, consideration of the benefits and burdens of such considerable investments deserve reasoned evaluation, free of ingrained misconceptions about transmission's fundamental but changing role in the present or future electrified economy. It is time to discard mythology and instead objectively consider the benefits that grid expansions, upgrades, and reinforcements can deliver to the economy and to consumers.

* * * * * *

WIRES submits this LEI paper for our readers' consideration and solicits the readers' comments, which may be submitted to www.wiresgroup.com We also acknowledge and thank the team of experts at London Economics, led by Julia Frayer, Eva Wang, and Marie Fagan and their colleagues from whose ingenuity and grasp of the industry's intricacies we all can learn.

KATHLEEN SHEA
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September 12, 2017

THE TRUTH ABOUT THE NEED FOR ELECTRIC TRANSMISSION INVESTMENT: SIXTEEN MYTHS DEBUNKED

September 2017

Prepared for

WIRES

By

Julia Frayer
Eva Wang
Marie Fagan
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LONDON ECONOMICS

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SYNOPSIS

WIRES commissioned London Economics International LLC ("LEI") to provide a White Paper on the myths and truths about transmission investment. The views of key decision makers regarding the need for transmission investment are often governed by widely-believed but outdated or inaccurate myths regarding the key drivers for investment, such as: trends in electric demand and supply; the cost of infrastructure and who should pay for it; benefits of investment; and the interplay between transmission and various new technologies. This White Paper identifies the principal myths surrounding consideration of transmission projects in regulatory, industry, and political circles and then explains why those myths are typically baseless, false, and misleading. The paper uses real-life examples of transmission investment projects to debunk these harmful misconceptions. In order to offer a more accurate portrayal of the need to invest in transmission infrastructure, this White Paper concludes with recommendations for practical and feasible improvements to the process of evaluating transmission projects.

BIOGRAPHICAL NOTE

Julia Frayer, Managing Director

Julia is the Managing Director at LEI with more than 20 years of experience providing expert insight and consulting services in the power and infrastructure industries. Julia specializes in the analysis and evaluation of electricity assets; she has worked extensively in the US, Canada, Europe, and Asia on issues that range from market analysis and valuation of electricity generation and wires assets, to policy development and strategy consulting. She has authored numerous studies and performed expert testimony on issues regarding transmission and generation investment, wholesale market design, energy procurement, renewable investment strategies, and policy analysis.

Eva Wang, Director

Eva is a Director at LEI. She is involved in many of the firm's modeling projects and price forecasting engagements, including evaluation of infrastructure investment opportunities and market rules changes. Recently, she headed the analytical team in charge of examining the costs and benefits of proposed transmission projects in New England.

Marie Fagan, PhD, Managing Consultant

Marie is a Managing Consultant and Lead Economist at LEI. With over 25 years of experience in research and consulting for the energy sector, Marie's focus at LEI relates to electricity and natural gas transmission, as well as broader strategic questions around investment for LEI's private clients.

Barbara Porto, Consultant

Barbara is a Consultant at LEI, where she provides research and analysis support to the firm's many engagements. Barbara recently supported a major client in its regulatory initiatives to implement incentive-based rates.

Jinglin Duan, Consultant

Jinglin is a Consultant at LEI, lending her technical skills to the firm's project evaluation and litigation engagements. Jinglin recently led an in-depth macroeconomic analysis of the impacts of construction of a transmission project.

London Economics International LLC ("LEI") is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation and distribution, water and wastewater provision, and natural gas distribution, with a suite of proprietary quantitative models to produce reliable and comprehensible results. LEI has offices in Boston, Chicago, and Toronto.

DISCLAIMER

The opinions expressed in this White Paper, as well as any errors or omissions, are solely those of the authors and do not represent the opinions of other clients of London Economics International LLC.

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1 Introduction and roadmap to this report

Why are there myths around transmission investment?

Myths are sprouted from small "seeds" that are grounded in reality but then grow to be "larger than life." The factual foundations begin to fade, and the embellishments soon become the focus of the story. With respect to transmission investment, myths have arisen as a shorthand to help navigate the complexities of transmission investment decisions. Unfortunately, trying to simplify the decision of investors and system planners down to a sound bite of several words creates inaccuracies and gives rise to myths that undermine beneficial investment opportunities.

Transmission investments are complex and large-scale, and they require careful evaluation, forward-looking analysis, and long-term commitments. Key issues in the decision-making process include the following considerations:

- **Transmission investment decisions are multi-faceted**. Electric transmission investment is a highly regulated, complex undertaking which involves many decision-makers.

- **Transmission investment is large-scale.** This creates almost an immediate natural tendency to consider deferral and smaller-scale, sometimes piecemeal, options because the costs and consequences of ***not*** pursuing a large-scale investment are typically ignored because they are more difficult to come to grips with.

- **Transmission investment requires long-term commitments and planning.** It can take 10 to 15 years to plan, permit, and construct new transmission, and sometimes much longer. Once built, transmission projects typically have economic and operating lives that are more than 50 years.

It is tempting to tame these complexities by relying on familiar myths to guide transmission investment decisions. However, as this report shows, using outdated myths to guide investment will result in missed opportunities for benefits to the power system, transmission users, and to electricity consumers. This report uses real-life examples to debunk the myths around transmission investment.

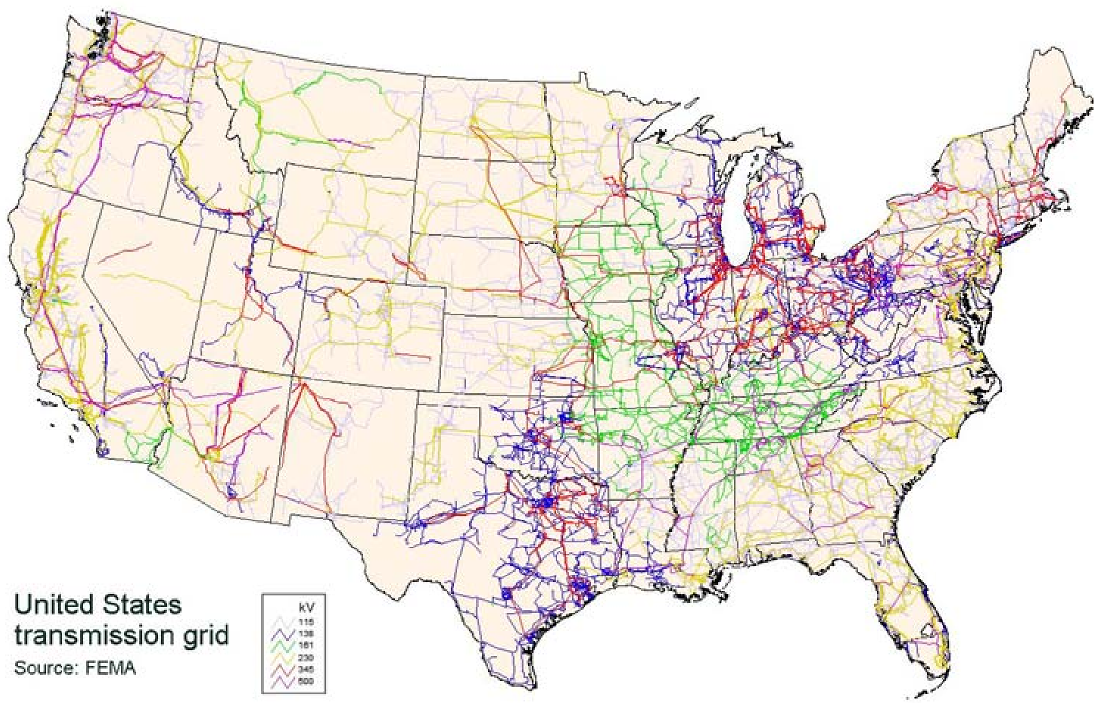
Roadmap

In Section 2, we briefly explain the important changes to the transmission system over the past two decades and the new realities that have resulted for the transmission system. In sections 3-7 we identify the myths and replace them with the new realities, or truths, about transmission. In Section 8, we provide recommendations for practical and feasible improvements to the process of evaluating the need for transmission investment to reflect these new realities. Some of the recommendations are already being practiced by system planners – if other decision-makers adopt these recommendations then their decisions around investment would more truly reflect the value that transmission investment brings to consumers and the power grid.

2 Why do we need transmission?

Electricity service is not simply about which power plants are running. Keeping the lights on involves an integrated network of resources, including: transmission lines, substations, control equipment, and local distribution lines (see Figure 1 below). Transmission infrastructure also ensures that the system is "reliable," meaning that the lights stay on even when power demand surges or an individual power plant goes offline.

Figure 1. The United States electric transmission grid



Source: Federal Emergency Management Agency ("FEMA")

Transmission investments are generally grouped into three categories:

- **Reliability:** Projects that are necessary to resolve a reliability issue (such as keeping the lights on);
- **Economic**: Projects that, while not necessary to resolve a reliability issue, allow cheaper generation to reach more load; and
- **Public policy:** Projects that assist in meeting public policy goals (e.g., lines built to support state renewable portfolio standards ("RPS") by, for example, allowing new remote wind generation to access load centers).

Investing in each of these three types of transmission requires long-term planning and a coordinated effort to ensure transmission is built where and when it is needed. The "drivers" of the need for new transmission were simple and straightforward: growing demand for electricity in a utility's service territory and the location of its power plants. The benefits of a new line were often taken for granted by the regulator, as long as the costs seemed reasonable and it was a straightforward exercise to allocate costs to consumers.

2.1 The evolving role of transmission

In the past, most transmission projects were developed by "vertically integrated" utilities that served a well-defined service territory and built power lines to connect its plants with its consumers, and consumers would only take services from this utility.

Nowadays, however, many regions of the US are served by independent power generators who own only power plants, and transmission and distribution utilities who focus only on delivering electricity to consumers. Even in areas where a single utility provides all services to consumers (and owns its own generation along with its wires businesses), there are now rules and regulations that require open access of the transmission system and "arms-length" considerations between the generation and transmission businesses. Independent system operators known as Regional Transmission Operators ("RTOs") or Independent System Operators ("ISOs") are now operating across the North American grid, and are in charge of the system planning and evaluation of transmission projects. Meanwhile, non-traditional investors are now allowed to 'compete' with utilities to build and own transmission projects. The line between consumers and producers is also blurring. Not only do consumers in some states have the right to choose their own supplier, but they also have an option to invest in their own generation facilities, thanks to the evolution of technology and regulatory reforms. In addition, many states have targets for renewable investment, which often call for additional transmission facilities to connect new generations with the load centers.

Thus, over the past few decades, the simple drivers of transmission have become less relevant, and new realities are driving the sector.

2.2 From myths to truths

Many common misconceptions around transmission investment have evolved from high-level generalizations about why transmission investment is needed and has led to oversimplification of the cost and benefits. These common misconceptions – "myths" – are detached from realities, or "truths," about transmission, and impose great challenge on efficient transmission development to meet current and future transmission needs.

These myths generally fall into five different categories, namely: (i) myths about power demand; (ii) myths about power supply; (iii) myths about alternatives to transmission; (iv) myths about costs; and (v) myths about benefits of transmission investments. We have identified a total of sixteen myths (see Figure 2) that need urgently to be corrected to better help system planners make informed decisions[1]—a topic which will be discussed in detail in the following sections.

Figure 2. Common myths around transmission investment

POWER DEMAND	1	Transmission is only built to meet current demand
	2	Demand is not likely to grow, no need for more transmission
POWER SUPPLY	3	Generating plants retire and new ones can use the same transmission lines
	4	No grid congestion, no need for more transmission
ALTERN-ATIVES	5	Local reliability issues can be addressed using alternatives
	6	Transmission is the most expensive option for resolving local reliability issues
	7	Customers tend to opt for new technologies and bypass the grid if they can
	8	New technologies are working well and can be easily scaled up to address grid stress
COSTS	9	There has already been enough investment in transmission so we don't need more
	10	Transmission projects are large and lumpy with high price tags
	11	Large transmission investment might end up underutilized
	12	Large transmission projects may be prone to overbuilding
	13	Large transmission investments involve complex cost allocation schemes that are unfair to consumers
BENEFITS	14	Customers on the receiving end are the only ones who benefit
	15	Transmission should only be built for resolving reliability issues -- benefits are uncertain for non-reliability projects
	16	Transmission investment is risky because the costs are certain but the benefits are not

[1] Some of the sixteen myths are bundled together in the detailed discussions in Section 3 through Section 7.

3 Myths and truths about electricity demand

There is more to electricity demand than what meets the eye. Even if the overall growth in traditional sectors of the economy that use electricity is not strong, electricity needs can be driven by new economic activities and new consumer uses for electric power.

3.1 Myth: Transmission is only built to meet current demand, which is not likely to grow. Constructing more transmission in anticipation of the unforeseeable future is a waste

A common misconception is that transmission is built solely to meet current peak demand. Given that the electricity demand growth is likely to be slow or even flat thanks to a low population growth rate in the US and energy efficiency improvements, there is no need for further investment in transmission—at least not in the near future.

3.2 Truth: Transmission is not only built to meet current demand, but also to manage evolving consumer behavior and new economic activities

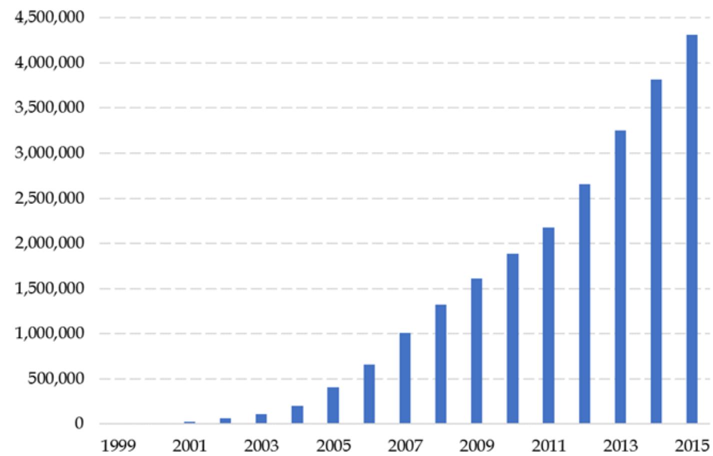
Even if "top-line" growth seems slow, electricity demand growth may accelerate in the near future as new consumer uses for electricity develop in new locations. Even as the US economy becomes more energy-efficient, the economy constantly evolves, as do consumer patterns of usage. For example, electric vehicles ("EV") sales have been emerging, and more and more homes are heating with electricity. In addition, specific local areas have experienced economic booms and therefore resulted in a large increase in electricity demand. It can take decades to plan and build a new transmission line—much longer than it takes for new uses of electricity to take hold—so it is best to plan ahead rather than waiting until transmission capacity constrains economic activity and consumer behavior.

A rapid penetration of EVs, as illustrated in Figure 3, will lead to higher demand for electricity and may require new transmission and distribution infrastructure. Although transportation electricity demand is currently very small compared with other end-uses, it is the fastest-growing aspect of electricity demand, with a compound annual growth rate of 2.4% per year, compared to the compound annual growth rate of the total load of 0.6%.[2] Many utilities are actively planning for these new loads by installing charging stations and other new infrastructure. For instance, in January 2017, three major investor-owned utilities in California—Pacific Gas and Electric Company ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas & Electric ("SDG&E")—submitted plans to the California Public Utilities Commission ("CPUC") to build EV infrastructure over the next five years.[3]

[2] Energy Information Administration. "Monthly Energy Review." July 2017. Table 7.6. Electricity End Use, data from 2000-2015.

[3] Greentech Media. "California Utilities Seek $1B to Build Out Electric Vehicle Infrastructure." January 24, 2017. <https://www.greentechmedia.com/articles/read/california-utilities-seek-1b-to-build-out-electric-vehicle-infrastructure>

Figure 3. Cumulative sales of electric vehicles in the US

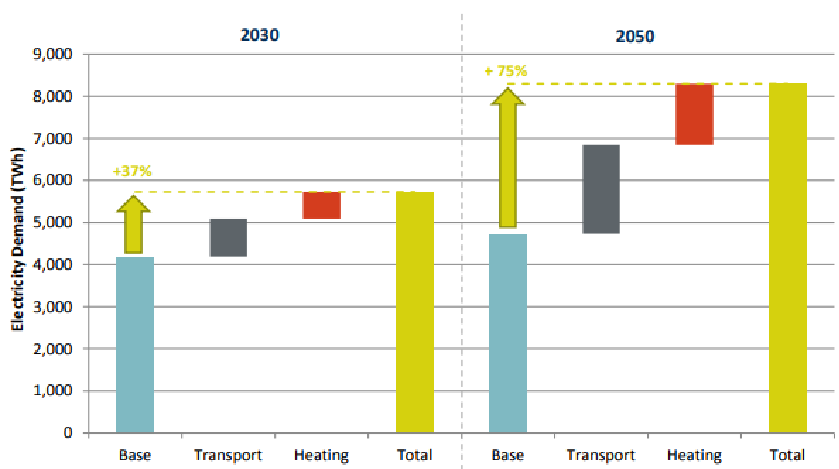


Source: Alternative Fuels Data Center. US Department of Energy. US HEV Sales by Model. January 2016. <http://www.afdc.energy.gov/data/10301>

Note: The figure shows the sales of both hybrid electric vehicles ("HEVs") and plug-in electric vehicles ("PEVs")

The increased popularity of electricity for home heating could also impact the seasonal and daily pattern of electricity demand and require new transmission upgrades. Figure 4 below shows an excerpt from another WIRES-commissioned analysis which demonstrates the profound implications from electrification of the transportation and heating sectors in the US. This analysis finds that by 2050, full electrification of land-based transportation could increase total electricity demand by 2,100 TWh (or 56% of 2015 electricity sales) and that full electrification of heating would increase electricity demand by about 1,500 TWh (or 40% of 2015 electricity sales).

Figure 4. Incremental electricity sales due to electrification of heating and transportation



Source: Brattle Group. "Electrification Emerging Opportunities for Utility Growth." January 2017.

3.2.1 Case study: Data center in Pennsylvania, New Jersey, Maryland Interconnection ("PJM") needed new transmission service

Data centers are a good example of a new use of electricity that has been growing rapidly driven by technology advancement. Electricity consumed in data centers in PJM increased from about 30 billion kWh per year in 2000 to 70 billion kWh per year in 2014.[4] In some cases, this economic activity added a brand-new end-use that required a new transmission service in affected regions. In PJM, the construction of data centers in the Dominion Virginia Power zone ("DOM") required new transmission lines. The increasing demand in the region from this activity has also been incorporated by the ISO in their long-term resource planning, as is stated in the PJM Load Forecast Report:

> "*The forecast of the DOM zone has been adjusted to account for substantial ongoing growth in data center construction, which adds 130-500 MW to the summer peak from 2017 through 2021.*"[5]

3.2.2 Case study: Shale oil and gas boom in Texas drove need for more transmission

The need for more electricity can also arise quickly in specific locations driven by new technology. Shale oil and gas development, for example, has created a significant load on the electricity system in areas of western Texas that were previously sparsely populated and with limited consumption of electricity. Even though the significance of such type of load demand growth might be zeroed out when viewed from a national level, it is crucial for sustaining regional economic activities and growth.

The fast-growing oil and gas industry in the Permian Basin (which lies in New Mexico and West Texas) is one example of how regional fuel production activities induce investment in transmission infrastructure. By 2016, oil production has reached two million barrels per day, double the level of 2011.[6] This has driven up electricity demand markedly in the Electric Reliability Council of Texas ("ERCOT")'s Far West zone, where the Permian Basin is located (see Figure 5). As a consequence of the unprecedented load growth, western Texas experienced transmission congestion, meaning that there was no available capacity on the line to transmit energy from lowest-cost plants, and thus loads had to be served by less-efficient, more-costly plants.

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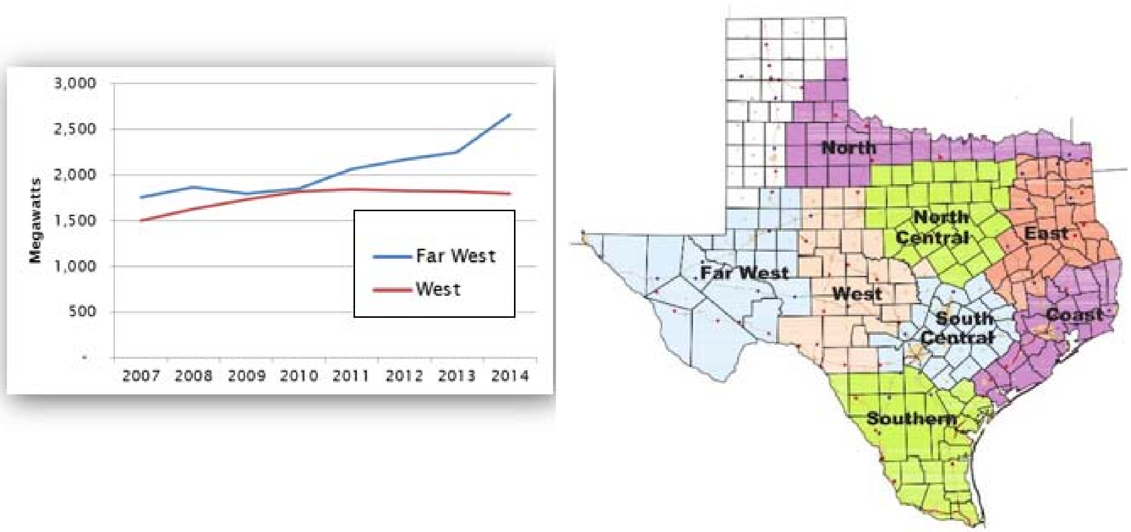
[4] Lawrence Berkeley National Laboratory, LBNL-1005775. *United States Data Center Energy Usage Report*. June 2016.

[5] PJM Resource Adequacy Planning Department. "PJM Load Forecast Report." January 2017. <http://www.pjm.com/~/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx>

[6] Energy information Administration and Texas Railroad Commission.

Figure 5. Maximum peak-hour electric power load, ERCOT West and Far West weather zones



Source: Energy Velocity, ERCOT

ERCOT, the transmission system operator for most of the state, noted that it was taken by surprise by the high demand for electricity triggered by the development of shale oil and gas:

> "*TDSPs [Transmission/Distribution Service Providers] and ERCOT did not fully appreciate the significant increase in energy intensity that was associated with the production operations for unconventional drilled wells used for the tight oil/shale plays versus operations associated with for the historical conventional drilling*."[7]

The ERCOT Board recently endorsed a transmission project that includes two new 345-kV lines to help address future reliability concerns in the growing region of Far West Texas. In the area where the project will be developed, peak electricity demand had increased from 22 MW in 2010 to more than 200 MW in 2016, and it is projected to exceed 500 MW by 2021.[8]

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[7] Energy Ventures Analysis. "West Texas Sensitivity Study Prepared ERCOT." June 2016.

[8] ERCOT. "ERCOT Board approves transmission project in West Texas." June 14, 2016. <http://www.ercot.com/news/releases/show/126322>

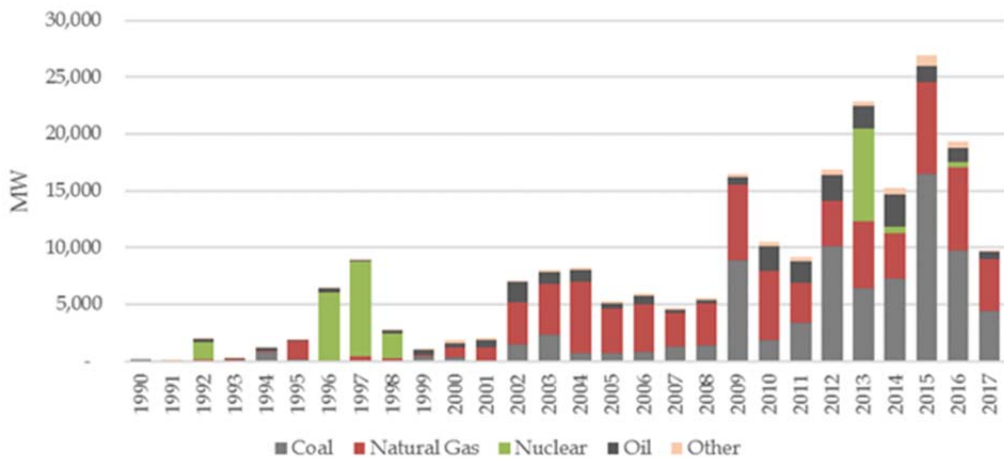
4 Myths and truths about electricity supply

Myths around electricity supply usually stem from misconceptions about how generation is connected with demand centers through the grid, or the idea that a transmission line can only provide one kind of benefit to the power system.

4.1 Myth: Retiring power plants will create room on the grid for new plants

Thousands of power plants in the US have reached the end of their useful lives in recent years (see Figure 6). As a result of the retirement of old power plants, there is a belief that there will be excessive spare transmission capacity on the system, and in sufficient quantities to interconnect new power plants. This faulty belief leads to the myth that investing in transmission to integrate new generation is not necessary.

Figure 6. US power plant retirements through June 2017



Source: Third party data provider

4.2 Truth: New power plants are not always built in the same place as retiring power plants

New power plants are not always built in the same locations as retiring power plants. New power plants are sited based on availability of fuel or other national resources needed for electricity production. For example, new wind plants are typically far from urban load areas or located where the grid is already at its performance limit. As a result, capacity freed up by retired power plants may not be utilized by new generation, without additional transmission infrastructure.

4.2.1 Case study: In New England, additional transmission is needed to bring new resources to market

In New England, more than 4,200 MW of generation is expected to have retired between 2012 and 2020, equivalent to almost 15% of the region's current (2017) generation fleet. According to the ISO-NE, an additional 5,500 MW of oil and coal capacity are at risk for retirement in coming years, and uncertainty also surrounds the continued operation of 3,300 MW of nuclear plants.[9]

Most of these retired or "at risk for retirement" power plants are located fairly close to load centers in central and southern New England (see Figure 7). Potential locations for new gas-fired generation are limited due to the lack of natural gas pipeline capacity and limited ability to access gas resources in many parts of the region.

Figure 7. Major planned retirement of non-gas-fired generators in New England

Source: ISO-NE. "2017 Regional Electricity Outlook – Retirements of Non-Gas-Fired Power Plants." <https://www.iso-ne.com/static-assets/documents/2017/02/2017_reo.pdf>

In the renewable generation sector, most of the new onshore wind power projects proposed to meet states' renewable portfolio standards ("RPS") targets are located in northern New England (mostly in Maine). While Maine has the best wind resources in the New England region, it is far

[9] ISO-NE. "Status of Non-Price Retirement Requests." August 15, 2016.

from load centers and the transmission system there is already constrained.[10] The independent system operator for New England, ISO-NE, stated the need plainly: "transmission improvements are needed to interconnect more wind power."[11]

4.3 Myth: The system is not congested so we do not need more transmission

Historically, congestion was seen by engineers as one significant symptom of an inefficient and constrained transmission system. This outdated and simplified conception leads to another myth, which states that transmission investment is only needed where there is congestion on the transmission system, or in other words, where the grid is constrained and performing inefficiently. If there is currently no congestion, building new transmission lines or upgrading existing lines is deemed unnecessary.

4.4 Truth: Some transmission needs arise even in uncongested energy markets

Although congestion relief is certainly one of the benefits of transmission, it is not the only factor that should drive investment.

Reliability problems, which could lead to voltage or thermal overloads and result in service interruptions for consumers, are not necessarily coincident with periods with congestion. Traditional transmission planning methods will consider a variety of system conditions, including various stressed transfers and generation outage profiles, that can identify key weaknesses in the transmission system even if significant congestion is not occurring on a day to day basis. In the case of the Greater Boston area in New England, for example, crucial reliability issues were identified by ISO-NE, even with full consideration of local generation. Therefore, even if there is no significant transmission related congestion under typical system conditions, there can be very critical reliability needs. In addition to reliability issues, there may be other economic or policy needs driving investment.

4.4.1 Case study: Greater Boston project addressed reliability in a normally uncongested system

In 2009, New England's transmission system operator, ISO-NE, reported that Greater Boston and Southern New Hampshire did not have adequate transmission resources to meet future demand reliably.[12] However, after 2009, there were important changes to the New England

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[10] ISO-NE. "2017 Regional Electricity Outlook." January 2017. *Note:* ISO-NE is conducting assessments to evaluate the potential economic effects on the regional power system resulting from different scenarios of wind integration and infrastructure improvements. The studies cover areas in Maine, as well as offshore wind development near Rhode Island and Southeast Massachusetts.

[11] ISO-NE. "Key Grid and Market Stats – Transmission." Accessed June 6, 2017. <https://www.iso-ne.com/about/key-stats/transmission>

[12] ISO-NE. "Greater Boston Transmission System. Needs Assessment Review – Solution Study Initiation." July 16, 2009. <https://www.iso-ne.com/static-

system, which would not only reduce congestion, but were also expected to solve the reliability problem. These changes included slower load growth, plant retirements, and new generation investment. However, though these changes reduced congestion across New England, there were still reliability problems in the Greater Boston area.[13]

To address the reliability issues, in 2015, ISO-NE selected a transmission investment plan with various upgrades to the existing infrastructure and new construction.[14] As of January 2017, five projects were completed and 12 additional projects were under construction. The whole investment plan is expected to be fully completed by 2019 to address identified transmission reliability needs in New England.[15]

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assets/documents/2016/02/07_16_2009_greater_boston_transmission_system_needs_assessment_review_solution_study_initiation_redacted.pdf>

[13] ISO-NE. "Greater Boston 2023 Solutions Study Status Update." November 20, 2013.

[14] ISO Newswire. "ISO-NE selects all-AC transmission solution to address grid reliability needs in Greater Boston." February 12, 2015. <http://isonewswire.com/updates/2015/2/12/iso-ne-selects-all-ac-transmission-solution-to-address-grid.html>

[15] Eversource. "Investor Call". February 22, 2017. Page 18. <https://www.eversource.com/Content/docs/default-source/Investors/2016-q4-and-y-e-financial-results.pdf?sfvrsn=0>

5 Myths and truths about alternatives to transmission

New technologies and alternatives to transmission can provide solutions to electric system needs that do not involve traditional transmission infrastructure. Alternatives to transmission come in a variety of forms and can include both demand-side (e.g. energy efficiency and demand response programs) and supply-side resources (e.g. utility-scale generation, distributed generation, energy storage, and smart grid technology).

There are several related myths about these alternatives to transmission, and they all reflect a misconception that there are cost-effective substitutes for every benefit and service that can be provided by transmission.

5.1 Myth: Transmission by wire is old technology. There are new and more cost-effective substitutes for transmission

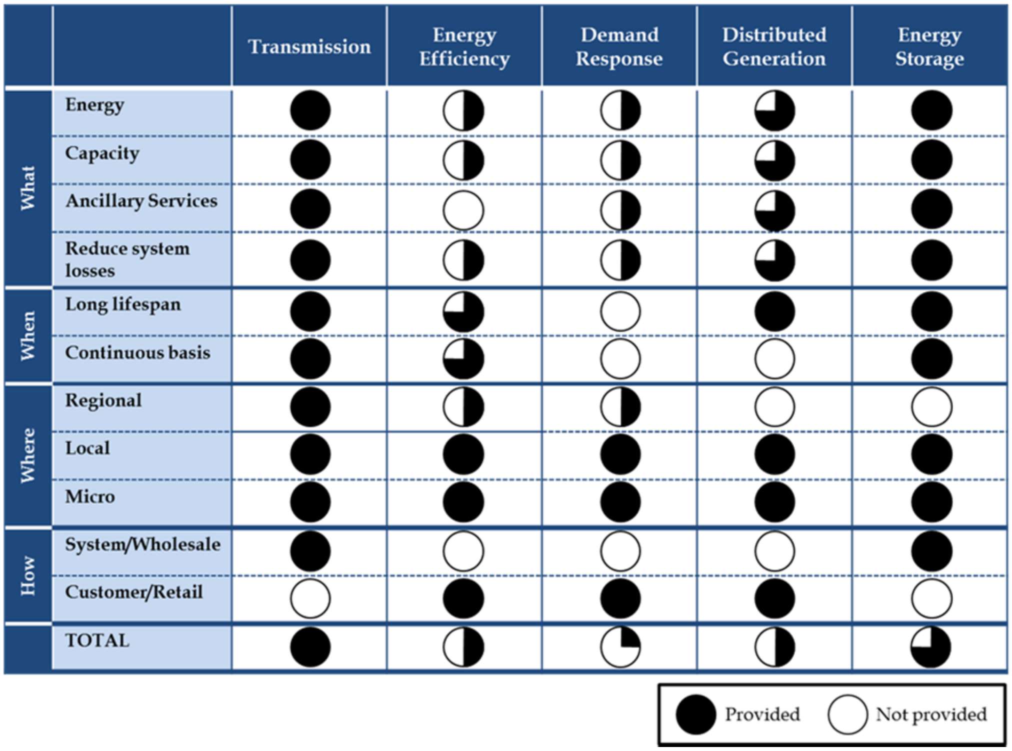
It is widely perceived that as distributed generation, such as behind-the-meter solar PVs and energy storage, is becoming more economic and more widely installed, it allows consumers to bypass the grid to satisfy their demand. In addition, energy efficiency and demand response programs are scaling up across the country, contributing to falling electricity demand. It is widely perceived that as distributed generation, such as behind-the-meter solar PVs and energy storage, is becoming more economic and more widely installed, it allows consumers to bypass the grid to satisfy their demand. In addition, energy efficiency and demand response programs are scaling up across the country, contributing to falling electricity demand. These alternatives are sometimes deployed to alleviate pressure on the grid, making transmission no longer the only solution that addresses the need for some transmission services. However, it is a misconception that transmission solutions are the most costly and time-consuming choice, and that alternatives are perfect substitutions for transmission.

5.2 Truth: Non-transmission alternatives ("NTAs") are not always apples-to-apples substitutes for transmission

While NTAs can meet some of the same technical needs of the system that drive transmission investment (for example, in solving certain reliability problems with system overloads or providing market efficiencies, like reducing congestion and motivating production cost savings), they are rarely a complete substitute to transmission as the benefits of NTAs (also known as market resource alternatives ("MRAs")) and transmission will vary in terms of tenure (duration), locational dispersion, and even functional impact (in terms of reliability versus market impacts).

Figure 8 provides a comparison of services that can be provided by transmission as well as various MRAs. Although often overlooked, it is important to recognize that transmission investment and MRAs are often complements to each other rather than substitutes. Individual MRAs/NTAs typically can provide only a partial suite of the services that transmission provides, and usually can meet only very specific and local needs.

Figure 8. Services provided by transmission lines versus MRAs



Source: London Economics International. *A WIRES Report on Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process.* October 2014. Pg. 13.

NTAs are also not necessarily cheaper—they may even undermine reliability when viewed in the context of the larger system in the long term or require often costly solutions at the end-of-life. For example, load reductions by demand-side resources, such as energy efficiency and demand response, are difficult to measure and are not necessarily permanent, which creates additional stress and risk to the system management and planning process.

Similarly, most distributed generation resources rely on intermittent technology—solar and wind —and are not able to provide services on a continuous basis on their own (without energy storage). They also present a challenge for system planners and operators who must manage the intermittency and attendant dispatch uncertainty for these distributed resources.

While energy storage resources can provide many of the same services as transmission, they are currently more expensive and less expansive than transmission in terms of geographical reach. With the exception of pumped hydro storage, energy storage technologies have not been widely deployed to date on a commercial scale, and are generally not yet cost competitive with other MRAs and transmission per unit of electricity produced or delivered.

6 Myths and truths about the cost of transmission

Transmission projects can be large-scale projects, and as such their costs are high on stakeholders' radar screens. However, costs should not be evaluated in a vacuum—one should also consider benefits of transmission investment, and those benefits need to be evaluated comprehensively. Electricity cost savings, reliability improvements, and local economic benefits all contribute to the benefit side of the investment decision.

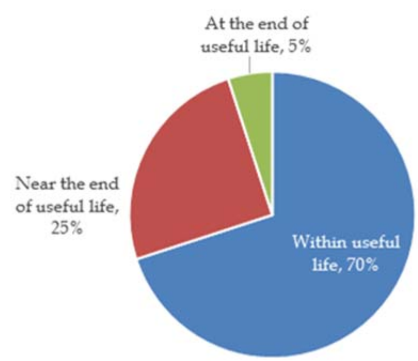
6.1 Myth: There has already been a substantial amount of investment in transmission, and many of the assets are fairly new so we do not need more

Investment in electric transmission has exhibited strong growth over the past few decades. From 1997 through 2012, annual US transmission investment rose $2.7 billion to $14.1 billion, a rate of 12% annually.[16] In 2015, annual transmission infrastructure investment reached a record of $20.1 billion for the US.[17] This has spawned a new myth: given this great amount of past investment dollars, there is no need for new investments on the current transmission system.

6.2 Truth: Assets are aging and some need replacement or refurbishment

Much of the US transmission system was built in the 1950s to 1970s with the boom in the economy post-World War II. By 2014, 30% of US transmission infrastructure was at or near the end of its useful life, according to the Edison Electric Institute (see Figure 9).

Figure 9. Current transmission infrastructure age, relative to useful life



Source: Edison Electric Institute ("EEI") / Harris Williams Co. "Transmission & Distribution Infrastructure." Summer 2014. <http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf>

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[16] EIA. "Investment in electricity transmission infrastructure shows steady increase." August 26, 2014. <https://www.eia.gov/todayinenergy/detail.php?id=17711>

[17] EEI. "Transmission Projects: At a Glance." December 2016.

Many elements of the transmission system need ongoing maintenance, repair, and upgrading, or in some cases complete modernization, as exemplified by the recent experience of the Pacific Direct Current Intertie ("PDCI").

6.2.1 Case study: The 45-year old Pacific Direct Current intertie ("PDCI") needed refurbishment

The PDCI is a high-voltage direct current system ("HVDC") 846-mile transmission line connecting the Oregon/Washington border, with Los Angeles. The transmission line carries hydroelectricity generated by the 31 dams of the federal Columbia River power system. Converter stations at the two endpoints convert the power from direct current ("DC") to the alternating current ("AC") used by the rest of the grid (see Figure 10).

Figure 10. The Pacific Direct Current Intertie

Source: Bonneville Power Administration. <https://www.bpa.gov/news/pubs/FactSheets/fs-201604-Celilo-Converter-Station.pdf>

The line went into service in 1970 with a capacity of 1,440 MW and has had numerous additional investments since then to meet increased capacity and reliability needs. Most recently, during 2014 to 2015, the Bonneville Power Administration ("BPA") invested $320 million to modernize the Celilo Converter Station at the north end of the transmission line. The project replaced vintage equipment, such as transformers, with new equipment that is faster, more reliable, and easier to maintain. It also reduced the converter station's footprint by half. Most notable among Celilo's new equipment are new transformers and digital controls to replace 40-year-old analog equipment. The upgrade was completed in 2016. As is demonstrated by the PDCI project, substantial investment is continuously needed to keep critical, existing facilities in good working order. Moreover, such maintenance and incremental investment allows system operators to capture incremental capacity improvements.

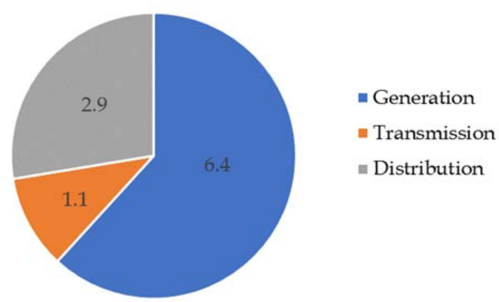
6.3 Myth: Transmission projects have large up-front costs which will be passed onto consumers

Transmission projects are often big and carry high price tags. In the US, the average cost for a 'typical' transmission project can range from $30 million to $300 million, depending on its scale. An interregional long-distance transmission project can cost as much as $1 billion or even more.[18] It is a myth that the best way to avoid high electricity bills for end-users is to avoid high price tags of large transmission projects.

6.4 Truth: The 'price tag' for construction of new transmission projects is recovered gradually, with only modest impacts on consumers at any given point in time

The cost of a transmission investment is spread over many years, over hundreds or even thousands of consumers, and over millions of kilowatt hours. Transmission costs account for only a small portion of the final electricity bill—typically around one cent per kilowatt hour, or 10% of the retail price (see Figure 11).[19]

Figure 11. Average retail electricity prices by service category, 2015 (cents per kilowatt hour)



Source: Energy Information Administration, Electricity Supply, Disposition, Prices, and Emissions. <https://www.eia.gov/outlooks/aeo/data/browser>

For an individual transmission project, even a large one, the impact is even smaller. A $2 billion project in a state the size of New York, multiplied by 18% (a rule-of-thumb for calculating annual revenue requirements), divided by an assumed 159,169 GWh of electricity consumption

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[18] Ibid.

[19] EIA. Factors affecting electricity prices. Accessed on July 11th, 2017. <https://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices>

(New York state's 2016 consumption level), would cost consumers far less than a penny per kWh consumed, only around \$0.00225/kWh.[20]

In contrast, generation (supply-related costs) accounts for the largest share of the electricity bill in the US, generally about 60%.[21] Drivers that impact the cost of generation, especially drivers such as fuel prices, have by far the largest impacts on monthly electricity bills and dwarf the incremental costs from transmission projects. In addition, transmission investments for projects designed to allow lower-cost generation resources to reach demand centers and to increase market competition help to lower costs of generation for end-users.

6.5 Myth: Large infrastructure investments might end up underutilized

Transmission planning is based on long-term commitments and must take into consideration potential future needs. However, failing to understand the complex evaluation process for transmission investment gives rise to the concern that the future is uncertain and that these future needs we are forecasting today may never come to fruition. These uncertainties lead to the myth that the transmission projects we are building for future need will very likely end up being underutilized.

6.6 Truth: Large projects are subject to detailed cost/benefit analyses, to help ensure their ultimate usefulness

Investment uncertainties around new transmission infrastructure can be quantified and analyzed comprehensively to mitigate the chances of a "bad" decision. For instance, transmission projects between Midcontinent Independent System Operator ("MISO") and Southwest Power Pool ("SPP") are required to have a benefit/cost ratio of 1.25 to the entire MISO region.[22] Such a benefit/cost ratio calculated for a range of future scenarios provides a high degree of certainty that the transmission investment will be prudent.

6.6.1 Case study: MISO evaluates a wide variety of benefits and imposes a high benefit-cost threshold to mitigate risk of underutilization

MISO gauges the value of proposed transmission projects under a variety of future policy and economic conditions across multiple quantitative benefit metrics. In its "Portfolio Economic Benefits Analysis," MISO acknowledges and considers a variety of qualitative benefits, such as enhanced generation policy flexibility, increased system robustness, decreased natural gas risk,

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[20] New York state demand was 159,169 GWh in 2016, NYISO. "2017 Gold Book." April 2017.

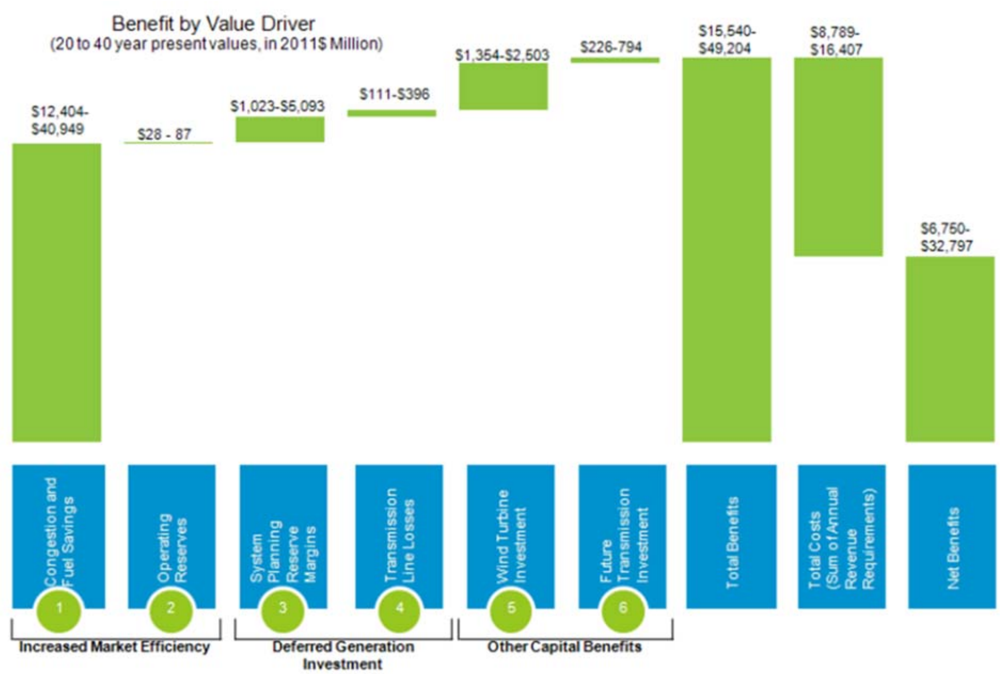
[21] U.S. Energy Information Administration, Annual Energy Outlook 2017, Reference case, Table 8: Electrical supply, disposition, prices, and emissions.

[22] FERC. Order Reject Tariff Revisions. Nov.30, 2015. Docket No. ER15-2705-000.

decreased wind generation volatility, local investment, and job creation, as well as carbon reduction (see Figure 12).[23]

MISO requires all its Market Efficiency Projects ("MEPs") to have a benefit/cost ratio of at least 1.25. MISO also imposes a higher hurdle for Multi-Value Projects ("MVPs"), expecting these to have benefit/cost ratios under all scenarios ranging from at least 1.8 to 3.0. These measures help to ensure economic efficiency and necessity of transmission investments at the early planning stage and avoid undue transmission expansion that could end up being underutilized.

Figure 12. Portfolio of economic benefits for Multi-value project in MISO's MTEP 2016



Source: "MISO Transmission Expansion Plan (MTEP16)." MISO. 2016. <https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Full%20Report.pdf>

6.7 Myth: Transmission projects may be prone to overbuilding

A common belief is that large infrastructure investments that are paid for by consumers, like transmission projects, are prone to "gold-plating," or in other words, over-sizing and over-spending beyond what is actually needed. Concerns that the costs of initially unused myth that will become a cost burden on consumers lead to the myth that smaller, piecemeal projects may be a better choice, because they have the appearance of lower up-front cost commitments.

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[23] "MISO Transmission Expansion Plan (MTEP16)." MISO. 2016. <https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Full%20Report.pdf>

6.8 Truth: Transmission projects go through stringent and comprehensive cost-benefit evaluations to avoid overbuilding

Multiple avenues for avoiding and correcting "gold-plating" exist. For large transmission projects, a stakeholder review is required by FERC, the ISOs/RTOs, and the state agencies to ensure that investments are appropriate. Other venues for ensuring projects are sized appropriately for benefits and market activities include competitive procurements, where market forces are harnessed to control costs.

"Gold-plating," or overbuilding, is often raised as an objection to transmission projects when stakeholders do not understand the benefits and focus exclusively on costs. However, it is equally, if not more, important to support long-term grid reliability as reliable electric service will contribute to economic activity in a region. Deferring investment in transmission may result in risks of service interruption and higher costs in the future.

6.8.1 Case study: PJM studied many options for AP-South congestion relief as part of stakeholder review to ensure an optimal transmission investment

In 2015, PJM began a stakeholder process and an extensive analysis process to examine efficiency, reliability, and congestion relief solutions along the AP-South corridor near the Pennsylvania-Maryland border.[24] The AP-South Congestion Relief Solution study analyzed 41 proposals (see Figure 13).

Based on the results of the initial study, PJM selected four projects that could each potentially solve the congestion problem and were well above the required benefit-to-cost threshold of 1.25. Of the four, Transource's Project 9A provided the greatest congestion benefits and highest benefit-to-cost ratio. However, based on feedback from PJM stakeholders and in an effort to develop the most robust solution, PJM conducted additional sensitivity analysis studies to assess different combinations of several similar proposals in the same region. The second study again demonstrated that Project 9A consistently provided the most benefits across the scenarios studied. The PJM Board finally approved Project 9A in August 2016. The project, which is required to be in-service by 2020, has an estimated cost of $320.19 million and an expected 15-year congestion and load payment savings of $622 million and $269 million, respectively.[25] Notably, Project 9A was one of the largest projects proposed of the 10 finalist projects, whose costs ranged from $40 million to $230 (except Project 9A).[26] Project 9A was nevertheless the most effective investment from the perspective of PJM and consumers.

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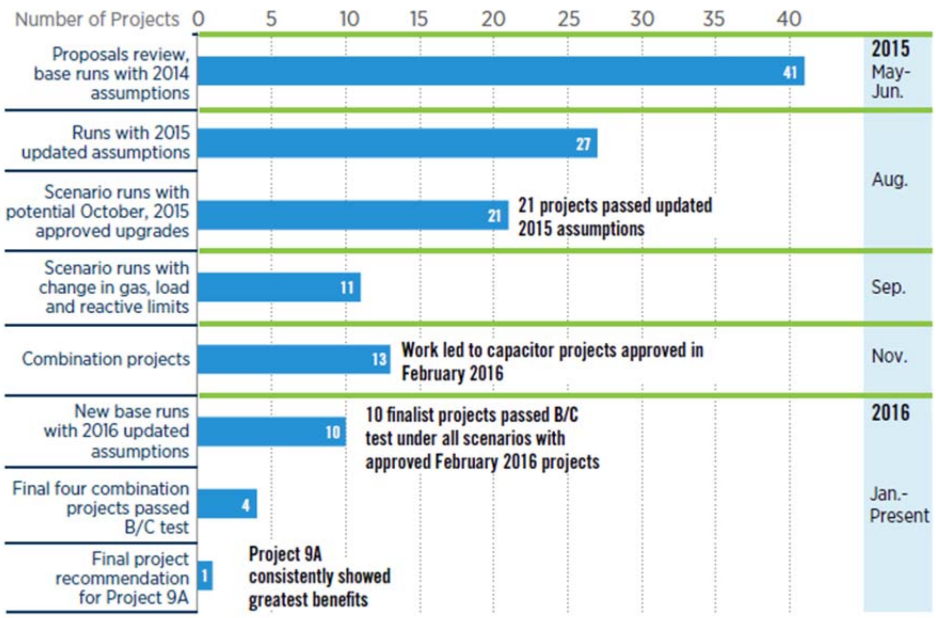
[24] PJM. "PJM Regional Transmission Expansion Plan 2016." February 28, 2017.

[25] Ibid.

[26] PJM. "Transmission Expansion Advisory Committee Market Efficiency Update." March 10, 2016. <http://www.pjm.com/~/media/committees-groups/committees/teac/20160310/20160310-market-efficiency-update.ashx>

Therefore, it is important to evaluate both the costs and benefits of a transmission investment, rather than focusing only on the costs, and a stringent and transparent evaluation process will include all the relevant costs and benefits.

Figure 13. PJM's review of options for AP-South congestion relief



Source: PJM. "PJM Regional Transmission Expansion Plan 2016." February 28, 2017.

6.8.2 Case study: AEP's 765-kV transmission project was novel in 1970s – but has since served as the backbone of its system

In 1969, American Electric Company ("AEP") developed the world's first 765-kV transmission line, a 68-mile line between Kentucky and Ohio.[27]

In 1966, when AEP first proposed this interstate ultra-high voltage transmission project, it was criticized as bold and unnecessary given engineering practices at that time. However, when the project was put into service, it eventually became the backbone of the electricity network in the Midwest by efficiently enabling interconnection of 1,300 MW generating units to serve the growing regional economy. Currently, AEP has over 2,100 miles of 765-kV network.[28]

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[27] AEP. "The Evolution of American Electric Power: Past, Present & Future." February 19, 2015. <http://energyweek.utexas.edu/files/2015/07/Crowder.pdf>

[28] Heyeck, Michael. "The Next Interstate System: 765-kV Transmission." *ELP. Electric Light & Power*. January 2007. <http://www.elp.com/articles/print/volume-85/issue-1/sections/td/the-next-interstate-system-765-kv-transmission.html>

Transmission investment must take into account long-term needs of the system and consider the technology that best achieves those needs. Investments perceived as "overbuilding" at one point can prove themselves as imperative to sustain a reliable and efficient grid system.

6.9 Myth: Project costs for interregional transmission projects are often unfairly allocated

Cost allocation is a challenge that frequently comes up, especially for interregional transmission projects. Determination of costs and benefits of a transmission project can be very complicated and the results can vary among stakeholders and variances can also arise under different methodologies. Opponents to transmission investments claim that cost allocation settlements can take years and result in long-term suspension and delay of transmission projects, causing electricity consumers and project developers to potentially be exposed to investment risks. Hence, a myth arises that large, interregional transmission projects should be avoided when possible.

6.10 Truth: Cost allocation issues are not insurmountable and can be resolved with both standard and customized solutions

Cost allocation is not a "new" issue. Transmission investment costs have been successfully allocated to different consumers since utilities first started charging for their services.

Significant progress has been made in developing and implementing standardized, widely-accepted cost allocation frameworks in recent years. ISO-NE, for example, has a default cost allocation mechanism for determining local and regional transmission costs. The MVPs in MISO are being developed based on a wide agreement of allocating the costs among benefiting states. The SPP region also uses a cost allocation mechanism for new electric transmission called "Highway/Byway" which was approved by FERC in 2010.[29] Meanwhile, customized tariff-based solutions, like in the case of the Tehachapi project in California described below, are possible where appropriate.

6.10.1 Case Study: Regional and local transmission cost allocation in ISO-NE – a standard solution

ISO-NE has established a well-accepted cost allocation scheme which has facilitated major transmission investments. Since 2003, ISO-NE/NEPOOL has adopted a default cost allocation mechanism, approved by FERC, which allocates transmission costs among six states and many different classes of consumers.[30] Every year, ISO-NE conducts a Regional System Plan ("RSP") which identifies a list of transmission projects that are expected to meet the reliability needs and

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[29] FERC. "Order Accepting Tariff Revisions. Southwest Power Pool, Inc. Docket No. ER10-1069-000." June 17, 2010. <https://www.ferc.gov/whats-new/comm-meet/2010/061710/E-7.pdf>

[30] FERC Technical conference on Connecticut infrastructure. *Allocating the Cost of New Transmission in New England*. January 6, 2005. <https://www.ferc.gov/CalendarFiles/20050124145350-Whitley,%20Cost%20Allocation.pdf>

bring economic benefits to the New England region. ISO-NE reviews the reliability of design proposed by transmission owners and determines what costs should be regionalized and what portions should be localized.[31]

Specifically, projects with 115kv and above capacity identified in the RSP are categorized as regional benefit upgrades, whose costs are allocated in proportion to each ISO-NE state's peak electricity demand, and are funded through a pool-wide postage stamp rate[32] for their regional network service. Smaller projects (generally less than 115kv and those which do not provide regional benefits) are categorized as local benefit upgrades, whose costs are allocated through a license plate rate.[33]

6.10.2 Case study: Tariff-based cost allocation for Tehachapi project – a customized solution

The Tehachapi Renewable Transmission Project ("TRTP") in California provides an example of a customized tariff-based solution to cost allocation for an inter-regional transmission project.

The Tehachapi area is one of California's leading resource areas for wind energy, but there was limited transmission infrastructure in the region to bring the wind energy to market.[34] Southern California Edison ("SCE") developed the TRTP 500 kV transmission line to deliver the wind energy to load centers in Los Angeles and San Bernardino counties, which allowed development of the wind resources of the Tehachapi area.

Segment 3 of this project was developed under a FERC-approved Location Constrained Resources Interconnection tariff ("LCRI"). Transmission owners paid upfront, and generators must pay pro-rata shares of costs when they interconnect and come in-service.[35] The TRTP line was energized in 2016.

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31 Fink, S. et, al. "A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations." NREL. February 2011. <http://www.nrel.gov/docs/fy11osti/49880.pdf>

32 Under a "postage-stamp" rate design, the costs of all existing transmission facilities in a large region are "rolled-in" and allocated to all consumers according to each consumer's share of the region's total load. As a result, the rate is the same for each consumer in the large region akin to a postage stamp that ensures delivery across the U.S., regardless of the distance.

33 Under a "license plate" rate design, the rates for transmission vary by zone, rates can be differentiated based on distance or other metrics between zones.

34 SCE. "The Tehachapi Renewable Transmission Project: Greening the Grid—Celebrating California's Progress in Renewable Energy." March 2010.

35 Ibid.

7 Myths and truths about the benefits of transmission

The benefits of a transmission project could be geographically widespread and take various forms. One needs to take a holistic view to assess the benefits of transmission projects, which will also help decision makers and transmission consumers to better understand the costs of transmission objectively.

It is critical to recognize that the potential benefits of a transmission project go way beyond meeting regional energy demand—they could also include storm hardening, increased competition in wholesale power markets, congestion relief, deferral of new generation or other upgrades, expanded economic activity, increases in state or local property tax collections, and numerous other attributes that may impact local economies.

7.1 Myth: Consumers on the receiving end are the only ones who benefit

It is widely accepted that transmission projects benefit the consumers who are receiving the power, but it is a myth that consumers on the receiving end of the transmission line (where the power is "sinking") are the only ones who benefit and that it is unfair for consumers in the regions along the route to also some of bear the cost.[36]

7.2 Truth: Benefits can be geographically and demographically widespread

From a geographic perspective, a state that is a source of supply ("source") may see benefits from the construction of the transmission line, including economic benefits during construction, economic benefits from taxes or other payments once the project is complete, as well as economic opportunities in the future for the development of new generation. Transit states or regions will see benefits from property taxes collected from the transmission operator in addition to potential electricity cost savings and environmental benefits. “Sink” locations, i.e. the receiving end, will see local economic and reliability benefits from more access to electric power and could also see “knock-on” effects from local economic boom from construction activities.

7.2.1 Case study: TransWest Express

The TransWest Express Transmission Project, a 600kV, 725-mile long transmission line, was proposed to provide 3,000 MW of capacity to deliver approximately 20,000 GWh/year of wind energy generated in Wyoming to Arizona, Nevada, and southern California. As of June 2017, TransWest Express has received approval from the Bureau of Land Management for its proposed right-of-way, and construction is expected to take place during 2018 to 2020.

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[36] Prepared by The Brattle Group, for WIRES. *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments.* July 2013. “WIRES Preface and Commentary.” Pg. 4.

Projected benefits of the line are not limited to the availability of energy to consumers on the receiving end. Four distinct economic regions along the transmission lines were identified as benefiting from increases in direct and indirect employment (see Figure 14). According to TransWest's preliminary economic impact study, direct employment associated with the construction of each region would average approximately 203 jobs over the construction period, and secondary employment is expected to reach, on average, 89 jobs over the construction phase.[37] Obviously, all regions along the route, not only the "sink," will benefit from construction activities of this project in terms of local economic growth and employment increase.

Figure 14. TransWest Express project route

Source: TransWest Express LLC. "Delivering Wyoming wind energy to the West." <http://www.transwestexpress.net/index.shtml>

7.3 Myth: Transmission should not be built for any reason other than for resolving reliability issues

It has been argued that transmission is only needed where there are reliability issues on the grid and that, as a result, non-reliability projects are not justifiable.

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[37] *TransWest Express EIS. Section 3.17 – Social and Economic Resources.* Western Energy. April 2015. Docket: DOE/EIS-0450. <https://eplanning.blm.gov/epl-front-office/projects/nepa/65198/78887/90846/06-Chapter3.17-SocialandEconomicResources.pdf>

7.4 Truth: A transmission project initiated for reliability reasons may have other economic benefits and vice-versa

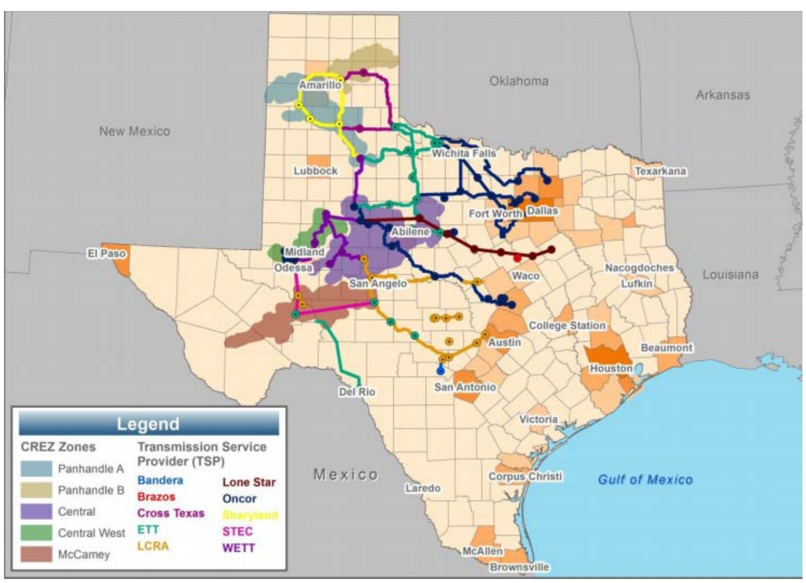
This myth overlooks the fact that transmission investment targeting reliability will naturally bring about other benefits, such as reducing system costs or providing a variety of economic benefits such as supporting local industries, and potentially motivate other investments.

New York and Texas are single-state RTOs, and thus state policy and oversight of the transmission system are easier to coordinate than in RTOs that encompass multiple states. Transmission investments in these states for purposes other than reliability are good examples of the reality of the multi-faceted nature of benefits. The Texas Competitive Renewable Energy Zones ("CREZ") initiative was aimed at achieving renewable policy goals, but also reduced system-wide wholesale electricity prices and has other benefits. In New York, when identifying a recent "public policy" project, the state examined broad categories of transmission benefits.

7.4.1 Case study: Texas built the CREZ lines based on policy drivers, with additional economic benefits to consumers

In 2008, the Public Utility Commission of Texas ("PUCT") established CREZ to encourage the building of long-distance transmission lines to bring wind power to the grid and to consumers. The goal of the CREZ initiative was to allow the delivery of energy produced by renewable resources (primarily wind) in the West and South zones to the load centers in North, South, and Houston zones (see Figure 15).

Figure 15. Competitive Renewable Energy Zones and transmission lines (completed)



Source: Warren Lasher, Director of System Planning, ERCOT. *The Competitive Renewable Energy Zones Process*, August 11, 2014. <https://energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf>

The impetus for CREZ came from the then-governor of Texas, Rick Perry, and concerns over the high fossil fuel prices at the time (2003). However, by the time the final recommendations of Perry's policy group, the Texas Energy Planning Council ("TEPC") were released, renewable energy, namely wind, had gained a central role in the energy plan. As Texas's abundant wind resources are far from load, the eventual legislation that resulted from the Governor's committee included support for the development of high-capacity long-distance transmission lines, as well as an increase of Texas's RPS requirements.

The CREZ transmission expansions were completed in January 2014, enabling dispatch of 18,500 MW of wind capacity.[38] Since the completion of the lines, wholesale energy costs system-wide (not just in ERCOT West, where most of the wind plants are located) have reflected the low cost of wind generation. Sporadic hourly negative real-time prices ERCOT-wide began after the CREZ system was energized and have persisted throughout 2015 (54 hours), 2016 (128 hours) and 2017 (35 hours as of July 2017)—even during summer months. Negative prices were seen in not only in one zone, but all across the system. These low energy prices are a concrete and measurable benefit to consumers (though they are challenging for some generators given the current market design). Thus, the CREZ lines not only helped meet renewable policy goals, but have provided electricity market benefits to consumers. An additional benefit is that CREZ lines can accommodate solar power, which tends to generate more during non-windy hours. Some of the CREZ lines have also provided system access to new consumers (see Section 3.2.2 for oil and gas developments). As such, CREZ projects have reinforced system reliability as well.

7.4.2 Case study: New York examined broad categories of transmission benefits to justify transmission investment

In 2015, New York Public Service Committee ("PSC") identified a very precise set of transmission upgrades in its footprint that would be necessary pursuant to the state's policy goals.[39] These upgrades would provide a 375 MW increase in the Central-East interface voltage transfer limit,[40] as well as increase by 939 MW the UPNY/SENY interface normal transfer limit.[41]

These upgrades are expected to reduce transmission constraints between the western and eastern regions of New York, which in turn will ease the downward pressure on western New

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[38] Malewitz, Jim. "$7 Billion CREZ project near finished, aiding wind power." October 14, 2013. <https://www.texastribune.org/2013/10/14/7-billion-crez-project-nears-finish-aiding-wind-po/> and ERCOT. *Competitive Renewable Energy Zones: Transmission Optimization Study*. April 2008.

[39] NY PSC. *Order Finding Transmission Needs Driven by Public Policy Requirements*. Case 13-E-0488. December 17, 2015.

[40] The C/E interface is typically voltage limited, therefore voltage limits were the focus of NYISO's evaluations.

[41] NYISO. *AC Transmission Cases: Updated Powerflow Analysis*. NY PSC Case 13-E-0488. October 8, 2015 (posted October 14, 2015).

York energy prices. In addition, the New York PSC also identified significant environmental, economic, and reliability benefits that could be achieved by relieving the transmission congestion in New York. The project continues to move forward—as of July 2017, the selection process of the to-be-constructed project and transmission sponsor is under way.

7.5 Myth: Transmission investment is risky, because transmission benefits are uncertain, while the costs are certain

Failing to understand the multi-faceted nature of transmission investment benefits, or evaluating a transmission investment in a short-sighted manner will inevitably bring about another myth: the benefits of transmission investments touted by developers are often intangible or "uncertain," but consumers are required to pay for the costs regardless whether benefits materialize. Due to this uncertainty of benefits, some stakeholders argue that large and costly transmission projects should not be pursued.

7.6 Truth: Transmission investment risks can be managed

Any investment involves uncertainty and risk. Yet risks can be managed through prudent analysis and decision-making. For example, some ISOs/RTOs specifically set high benefit-to-cost ratio thresholds to ensure that risky projects are not undertaken (see discussion in Section 6.6). Other ISOs/RTOs, such as CAISO and MISO, also evaluate a broad set of scenarios to test whether benefits are robust across a wide range of uncertain outcomes.[42]

Uncertainty is also bi-directional. In other words, the actual benefits could be larger than estimated benefits. This is especially true if the benefit analysis was conservative.

Furthermore, not all benefits of transmission investment are immediate or obvious; some may be hard to quantify and others may have different values for different stakeholders. However, as explained in-depth in Section 7.2 and Section 7.3, benefits of transmission investment take various forms, are spread extensively geographically, and last for decades (as described in other WIRES white papers, see Figure 16).

[42] CAISO. *Transmission Economic Assessment Methodology.* June 2004. See also Section 6.6 for discussion of the MISO evaluation process.

Figure 16. Potential benefits of transmission investments

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

Source: WIRES. "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments." July 2013.
<http://wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf>

8 From myths to reality: Recommendations for a change of perspectives in investment planning and decision-making

To avoid myths and to think about transmission investment realistically, decision makers need to adopt a comprehensive and consistent approach to evaluating the costs and benefits of transmission.

LEI recommends that this approach recognize a common set of evaluation criteria (or metrics) across all types of transmission projects (see Figure 17). Even if a project has been proposed for reliability, for example, it might also have benefits related to market efficiency and/or policy. Applying a broad set of metrics to every transmission investment would ensure that all potential benefits would be captured for evaluation.

Figure 17. Evaluation metrics should be comprehensive and consistent

Evaluation metric
Price reduction benefits
Production efficiency gains
Generation capacity cost savings
Environmental benefits
Competitive market benefits
Load diversity benefits
Public policy benefits
Macroeconomic benefits
Reliability benefits
Fuel diversity benefits

8.1 Costs and benefits should be evaluated as a whole package

Some benefits of a transmission project tend to increase over time with both load growth and fuel price inflation. At the same time, costs tend to leave an impression of being "front-loaded," although in fact, the investment costs are typically spread over many years in rates to consumers, and decline over time as capital cost is depreciated. Transmission investments have benefits and cost lives that extend well beyond 40 years. In spite of this, many transmission investment decisions are made based on comparisons of costs and benefits over a much shorter period than the typical 40-year useful life of the asset, for example, for the first 10 years of a project. Requiring a comparison of the first 10 years of estimated benefits with annual transmission consumer costs for the same number of years raises the benefit-to-cost threshold that projects must overcome.[43] Instead, we recommend analysis of benefits over a longer period

[43] The Brattle Group. *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*. July 2013. Pg. 17.

to better match the life of the investment. In addition, it is important for benefits of investments to be measured against an accurate view of the world of not doing the project. Frequently, opportunity costs are ignored even though the costs of a reliability shortfall are well recognized.[44]

There are many other dimensions of costs and benefits that need to be paired accurately to ensure that sound decisions are being made, as discussed below.

8.2 Transmission alternatives need to be examined comprehensively

As noted previously, alternatives to transmission (NTAs and MRAs) and transmission investment offer a range of different types of benefits. While it is true that MRAs can provide valuable services, transmission infrastructure tends to provide a broader array of benefits that accrue to a wider variety of parties over a larger geographical dimension (as well as to local areas). Thus, an optimal process is not one that poses an either/or decision (treating transmission and MRAs as substitutes), but one which treats them as potential complements, and asks "how much of each should we use in this circumstance?" When considering the costs, the cost of subsidies provided to some distributed generation such as behind-the-meter solar PV should also be included as an indirect cost. In addition, positive and negative externalities should be considered, thereby evaluating indirect benefits or costs on various stakeholders.

8.3 Recognize that certainty of costs and uncertainty of benefits can be an illusion

It is easier to perceive the costs of an investment than to envision its benefits. The cost of an investment is up-front (at least when described in capital spending terms) and "known" while benefits can be of varying magnitudes over time and will depend upon how the future unfolds. In addition, it is difficult for most stakeholders to perceive the cost of not taking action. However, there are real costs to inaction—system reliability can hamper local economic activities (for example, if there is simply insufficient electricity to meet demand, some economic activities will need to be interrupted). Inaction can also increase the cost of electricity (due to the lack of efficient resources and rising congestion when existing transmission capacity is "used up").

8.4 Plan for the future

Not only is transmission a long-lived asset, its required siting, permitting and construction time frames are also lengthy, as noted previously. Thus, investors need to project drivers for transmission investment many years into the future, so that when the transmission development project is finally completed and energized, it will be the right size, and in the right place. For example, the timing of many nuclear license expirations (for the 2030s and early

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[44] Frayer, Julia, et al. *Estimating the Value of Lost Load—Electric Reliability Council of Texas*. LEI. June 2013. <http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf>

2040s) seems far into the future right now; but a transmission development process that begins in 2018 and takes 10-15 years to complete will result in a project that will serve the market for many years *after* those nuclear plants retire.

8.5 Overcome the natural human tendency to over-rely on recent experience

Looking out over the long term, developing realistic assumptions for forward-looking investment analysis and system planning is not straight forward. The use of scenario analysis to understand and quantify some of the uncertainties in long-term investment can be valuable. Scenarios should include a "business as usual" scenario, as well as alternative scenarios that contain various transmission solutions and technically-suitable alternatives, or alternative values for drivers (such as varying assumptions for future natural gas prices, economic activities and consumer behavior patterns around electricity use).

Scenario analysis is built on plausible futures that are intended to envelop the range of outcomes, not just outcomes that mirror recent experience. If all the scenarios were to identify meaningful benefits, that suggests that even if one were uncertain about the future, there would be benefits to the investment regardless of which scenario was actually realized.

8.6 Plan for the unexpected

A "most-likely" analysis cannot capture the impact of unlikely but extreme events. These events can have expensive consequences for consumers. For example, during the winter of 2013/14, the coldest winter in 20 years in many places,[45] there were in fact three "Polar Vortexes" that extended across the Eastern seaboard of the US. Many ISOs/RTOs saw unprecedently high winter peak loads and experienced very high energy prices (see Figure 18). For instance, the NYISO set a new record winter peak load of 25,738 MW, and requested voluntary reduction from about 900 MW of its demand resources.[46] ISO-NE reached a peak just short of its all-time historic peak and also called for demand response resources to be ready for deployment.[47] PJM and some providers in South Carolina had to cut voltage in their areas by 5%, while South Carolina Electric & Gas was forced to disconnect some consumers to ensure that the power grid could remain within safe operating limits and could withstand a worsening of the emergency.[48]

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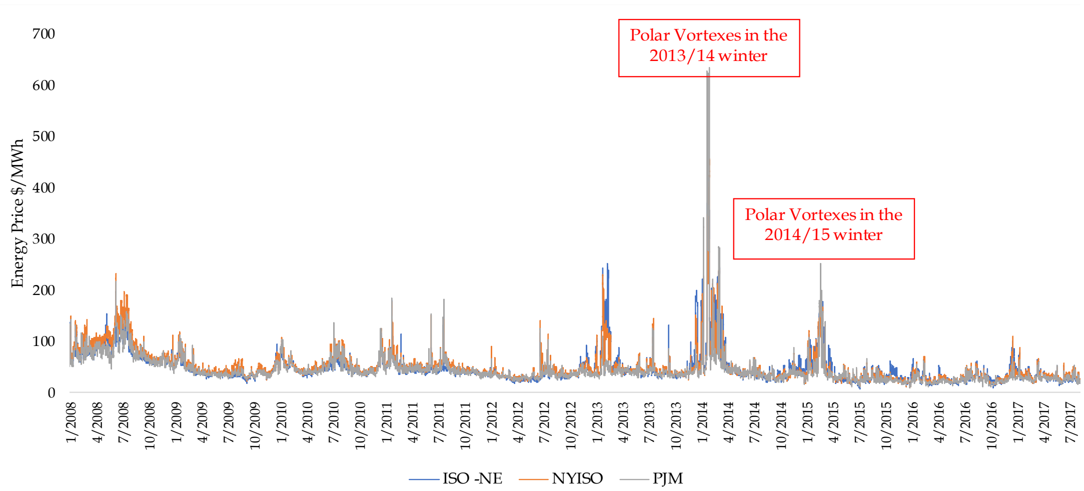
[45] NERC. *Polar Vortex Review.* September 2014. <http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf>

[46] NYISO. *Winter 2013-2014 Cold Weather Operating Performance.* March 2014. <http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2014-03-13/Winter%202013-1014%20NYISO%20Cold%20Snap%20Operations%20EGCW-MIWG.pdf>

[47] FERC. *Winter 2013-2014 operations and market performance in RTOs and ISOs.* April 1, 2014. <https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf>

[48] Kemp, John. "U.S. power grid survived polar vortex, but only just: Kemp." *Reuters.* October 3, 2014. <http://www.reuters.com/article/us-usa-power-weather-kemp-idUSKCN0HQ4TB20141003>

Figure 18. Energy price hikes in New England, New York, and PJM during Polar Vortexes



Note: The figure presents rolling hourly LMPs for the Internal Hub in ISO-NE, New York City (Zone J) in NYISO, and PSEG zone in PJM, from January 2008 to July 2017.

Source: Third-part data provider.

A system-wide blackout can amount to billions of dollars of economic losses. For example, the total cost of a 12-hour system-wide outage in MISO, which has an outage cost of $3,500/MWh and an average hourly load of 76,850 MWs, would amount to $3.2 billion.[49] Prior economic studies have pinpointed economic losses from the blackout of 2003 to as much as $4-$10 billion.[50] A transmission line can help moderate consumer rate hikes due to weather driven events and could in some circumstances make the system more resilient and insure against an expensive system-wide blackout.

8.7 Conclusion

Decision-making around transmission investment is complex and multi-faceted, and each transmission project is unique to some degree in the mix of benefits it can provide to consumers and the electric system. As we have shown, relying on outdated myths can handicap the decision-making process, mistakenly reject valuable transmission investment, and result in missed opportunities to benefit consumers. We must strive to correct the myths in our thinking about transmission investment and must also move the investment analysis in a direction which will allow us to avoid the trap of making more "myths." In doing so, we can thereby ultimately support more informed transmission investment decision-making in the future.

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[49] MISO Market Subcommittee. "Evaluating Energy Offer Cap Policy Market Roadmap." May 3, 2016 and Energy Velocity (data for average hourly load in 2016).

[50] U.S. Department of Energy, U.S.-Canada Power System Outage Task Force. "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations." April 2004. <https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf>

9. Appendix: Acronyms

AC	Alternating Current
BPA	Bonneville Power Administration
CPUC	California Public Utilities Commission
CREZ	Texas Competitive Renewable Energy Zones
DC	Direct Current
DOE	US Department of Energy
DOM	PJM Dominion Virginia Power Zone
EEI	Edison Electric Institute
EIA	US Energy Information Administration
ERCOT	Electric Reliability Council of Texas
EV	Electric Vehicles
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
LCRI	Location Constrained Resources Interconnection
LEI	London Economics International LLC
MEP	Market Efficiency Project
MISO	Midcontinent Independent System Operator
MRAs	Market Resource Alternatives
MVP	Multi-Value Project
NERC	North American Electric Reliability Corporation
NTAs	Non-transmission Alternatives
NYISO	New York Independent System Operator
PDCI	Pacific Direct Current Intertie
PEVs	Plug-in Electric Vehicles
PG&E	Pacific Gas and Electric Company
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PSC	Public Service Committee
PUCT	Public Utility Commission of Texas
PV	Photo Voltaic
RPS	Renewable Portfolio Standard
RSP	Regional System Plan
RTO	Regional Transmission Organization
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SPP	Southwest Power Pool
TEPC	Texas Energy Planning Council
TRTP	Tehachapi Renewable Transmission Project

APPENDIX C

Service Provided by Market Resource Alternatives Compared to Transmission Services

		Transmission	Energy Efficiency	Demand Response	Distributed Generation	Energy Storage
What	Energy	●	◑	◑	◕	●
	Capacity	●	◑	◑	◕	●
	Ancillary Services	●	○	◑	◕	●
	Reduce system losses	●	◑	◑	◕	●
When	Long lifespan	●	◕	○	●	●
	Continuous basis	●	◕	○	○	●
Where	Regional	●	◑	◑	○	○
	Local	●	●	●	●	●
	Micro	●	●	●	●	●
How	System/Wholesale	●	○	○	○	●
	Customer/Retail	○	●	●	●	○
	TOTAL	●	◑	◔	◑	◕

● Provided ○ Not provided

Source: London Economics International. *A WIRES Report on Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process.* October 2014. Pg. 13.