

A WIRES REPORT



**WELL-PLANNED ELECTRIC
TRANSMISSION
SAVES CUSTOMER COSTS:**



**IMPROVED TRANSMISSION
PLANNING IS KEY TO THE
TRANSITION TO A CARBON-
CONSTRAINED FUTURE**

THE BRATTLE GROUP

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WIRES: Voice of the Electric Transmission Industry

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WIRES' Preface

Changing The Way We Plan Major Transmission Expansions Can Save Customers Billions During The Coming Transition To New Forms of Electric Generation, New Modes of Managing The Grid, and New Uses of Electricity

WIRES¹ offers this white paper as part of its ongoing mission to provide policymakers and practitioners in the electricity industry with insight into the policies and regulation governing the development of the integrated North American high voltage electric transmission system. As WIRES has indicated in past reports, the role of transmission and the benefits it provides have often been overlooked or prematurely dismissed. In addition, the prevailing regulatory processes and planning requirements that govern transmission development today, such as existing regional and interregional planning processes and cost allocation methodologies, that were put in place to comply with Order No. 1000, are not always in the long-term public interest of consumers or our economy.

As a result, the industry is facing a period of adaptation to new environmental regulations, technologies, and market conditions with a grid largely built to serve the analog economy of the mid-1900s. Left unaddressed, this situation could lead to costly outcomes for customers and constrained choices for policy makers and regulators. The time is *now* to undertake a proactive, scenario-based transmission planning effort to ensure the grid can meet the challenges of a rapidly evolving generation fleet while capturing significant cost savings for customers. If planned, constructed, and paid for with its near- and long-term benefits to consumers in mind, a 21st century grid will

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.

its near- and long-term benefits to consumers in mind, a 21st century grid will provide the flexibility, strength, and the quality of service our economy requires and electricity customers expect.

The purpose of this paper² is not simply to re-argue the merits of transmission as a key element of our highly electrified economy and society. Instead, the paper highlights for regulators, legislators, and members of the general public the often-underestimated value of our electric grid. More poignantly, it emphasizes that not improving transmission planning soon in anticipation of foreseeable future developments poses potentially major risks and costs to customers. As market drivers, economics, technology, and public policies such as EPA's Clean Power Plan (CPP) fundamentally overhaul how electricity is produced and consumed, a robust transmission system is key to helping ensure that electricity can be delivered in the most cost-effective, reliable, and safe manner.

The economists at The Brattle Group take a comprehensive look at the rapid changes that are occurring in the electricity industry, particularly as they relate to how environmental regulations, market forces, and technological changes are destined to affect the generation fleet. Consequently, they recommend that policymakers, regulators and transmission planners change their views about the methods used for system planning and transmission development.

Chief among their points, the Brattle Group economists argue for “anticipatory” transmission planning which includes scenario-based analysis that explicitly considers the uncertainties faced by the industry and is used to

² This new analysis builds on the Brattle Group's 2013 report on the benefits of transmission investments and how to determine if the benefits of transmission exceed its costs. *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investment*, prepared for WIRES (July 2013) The Brattle Group (Chang, Pfeifenberger, Sheilendranath) followed with a report card on transmission planning and the tremendous costs and risks to consumers and society of *not* developing the grid we will inevitably need. *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid* (April 2015). All reports are available at www.wiresgroup.com.

evaluate a broad range of options and transmission benefits. Such a forward-looking approach moves beyond customary 5-10 year planning horizons and the dominant but limiting focus on preserving reliability. This comprehensive approach will be key for addressing the next generation of electricity supplies and consumption in a more cost-effective manner.

The paper also reflects the impact that CPP and similar environmental regulations will have on transmission policy and planning. In what many observers see as one of the most impactful energy policy initiatives in recent history, the EPA's CPP rulemaking does not adequately address the critical role of transmission and the need for upgrades to the grid, even while requiring a massive shift in electric generation resources needed to comply with the regulations to curb greenhouse gas emissions. The CPP likely will increase the retirement of a substantial amount of coal-fired generation and the interconnection of significant amounts of new renewable energy and natural gas-fired generation to serve major consumer markets. Major new transmission additions and upgrades will clearly be required to achieve cost-effective compliance. However, because the CPP's accelerated "glide path" for implementation calls for compliance starting in 2022, the long lead time needed to plan and construct transmission (typically 5 to 10 years or longer in some cases) and the short timeframe for compliance creates a disadvantage for transmission to be considered among compliance options in and of itself and as an enabler of other compliance options.

WIRES supports the efforts of RTOs such as MISO, PJM, and SPP that are conducting planning studies to identify transmission that might be needed for CPP compliance, the Supreme Court stay notwithstanding, and to address other drivers such as economic forces and developments under various scenarios. WIRES, however, also believes there is not a clear, consistent picture for policy makers and regulators to consider of how regional and interregional transmission investments can reduce the total costs and risks to customers.

In sum, this paper confirms WIRES' long-time contention that planning, upgrading, and expanding the North American high voltage electric transmission system increment-by-increment, without a regional and interregional vision or an appreciation of what will be required of the system to serve consumers cost-effectively, reliably, and safely in the future under a broad range of plausible scenarios, creates the risk of leaving customers with only a very expensive, cost-ineffective set of choices. With this said, the paper makes the following key points for policy makers, regulators and the industry to consider:

- A more proactive and immediate approach to building a strong transmission grid will yield net savings in total generation and transmission investment costs ranging from \$30-70 Billion through 2030 for compliance with current regulations, up to almost **\$50 Billion in savings annually on consumers' bills in "an even more environmentally constrained future."**³ Whether fundamental changes in the generation mix are driven by the economics of energy markets or by public policies, including state and federal de-carbonization plans, timely investments in transmission will likely produce substantial cost savings for consumers over the long term. With respect to public policy drivers, EPA's CPP has not expressly recognized that increased transmission investment would be *essential* to delivering cost-effective lower carbon resources to market.⁴ In addition to this need for physical interconnection, the Brattle Group analysis shows that well-planned deployment of additional transmission will actually reduce the overall cost of compliance with the CPP.
- Given the long lead times in transmission planning and development, there is little time to waste in readying the grid to help reduce the cost of meeting the profoundly changing market fundamentals. Planners should

³ WIRES interprets the reference to future constraints as meaning a generally foreseeable reduction in the use of high-carbon-emitting resources in the process of producing electricity. In the next two or three decades, that change will be driven by market economics and new technologies as well as by economic policy and environmental regulation.

⁴ *Comment of WIRES On Carbon Pollution Emission Guidelines For Electric Utility Generating Units* (Docket No. EPA-HQ-OAR-2013-0602), December 1, 2014. Available at www.wiresgroup.com

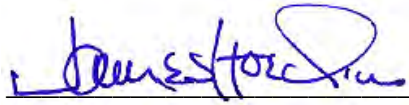
not hesitate to begin planning the transmission upgrades that will almost certainly be needed to accommodate the various changes in the electricity industry.

- Transmission planning must address environmental regulation, technological challenges, and a rapidly changing fuel mix that we can already foresee – from a regional and interregional perspective. To the extent we lack perfect knowledge of the future and still face significant uncertainties about environmental policy direction, it remains critically important to understand that transmission provides optionality and a basis for accommodating the uncertain or even the unforeseeable.
- Employing “anticipatory” transmission planning tools is an opportunity for policy makers, regulators and planners to better understand and re-design what the grid can do to lower costs for customers, help the industry adapt to new technologies, and make better use of existing rights of way.
- The highest expression of the interstate commerce in electricity will be interregional projects which enlarge markets, capture the available savings, reduce risks, distribute the benefits of investment most broadly, and tap currently inaccessible energy resources.
- Policymakers, regulators and the industry should be planning for a broad range of plausible scenarios and not be focused mostly on “base case” planning assumptions. Because the industry, its market conditions, and even its regulations are invariably going to change, today’s conditions should not be relied upon as the primary, let alone the exclusive, basis for how the industry will utilize transmission facilities constructed in the next decade or two for service 20, 30, or 40 years into the future.

WIRES solicits and looks forward to your comments and questions, which may be submitted to www.wiresgroup.com



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Improved Transmission Planning is Key to
the Transition to a Carbon-Constrained
Future

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Executive Summary

The electric power industry is transforming rapidly due to low natural gas prices, technological changes, dramatic cost reductions in renewable generation, and increasingly ambitious environmental policy goals and consumer preferences. The Environmental Protection Agency's (EPA's) Clean Power Plan (CPP) is perhaps the most visible and heavily-debated regulatory mandate in this trend toward an environmentally-constrained electricity industry. Much of the industry's discussion about CPP and related environmental objectives has focused on energy efficiency, reducing coal-fired generation, and adding more renewable generation. This whitepaper complements those discussions by showing how a well-planned transmission system can help meet environmental objectives at lower overall costs, saving customers tens of billions of dollars compared to a system that is primarily planned to focus on more immediate needs to meet reliability requirements.

The current uncertainties over CPP implementation are not likely to change the ongoing trend toward a clean power future, given that both market forces and policy preferences for cleaner energy sources are pushing in the same direction: natural gas prices currently are projected to remain relatively low for the foreseeable future, the costs of various renewable energy technologies continue to decrease, and customer preferences are evolving toward having more control over their energy usage, including the energy source. Furthermore, many states, towns, corporations, and consumers are pursuing their goal of reducing emissions from electricity generation, independently of federal and state regulations. Such trends will invariably shift the country's generation mix from coal to natural gas and renewable resources, with necessary upgrades to the nation's transmission grid.

A Brattle study conducted in 2008 estimated that the U.S. would need approximately \$1.5–\$2.0 trillion of capital investments in the power sector over 20 years. Of that total projected investment need, transmission accounted for approximately \$300 billion while generation accounted for \$500 billion to \$1.0 trillion (with the remainder representing distribution investments).¹ A more recent study prepared for the Eastern Interconnection States Planning Council (EISPC), National Association of Regulatory Utility Commissioners (NARUC), and the Department of Energy (DOE)² similarly projected approximately \$1 trillion in generation investment needs over the next 20 years, with at \$50–110 billion of *interregional* transmission needed to cost-effectively support the generation investments. These capital cost estimates are immense and, rightfully, they will attract the scrutiny of regulators and policymakers. However, while these estimated numbers are large, they do not yet consider how improved transmission planning can help reduce overall costs in the face of shifting generation mix, evolving regulatory requirements, and changing demands of electricity customers. Because overall investment need

¹ Chupka *et al.* (2008)

² EISPC (2013).

and costs are large, we are articulating in this paper how the industry can improve planning to achieve a more cost-effective power system and reduce customers' overall costs.

As we show in this white paper, a more flexible transmission grid will be a critical component for more cost-effectively serving electricity customers in a rapidly changing industry. The shifting generation mix, a more diverse geographical production patterns, trends in fuel costs, and technological improvements will require a holistic examination of how various regions and the country as a whole can take advantage of a more robust power grid that minimizes customer costs over the long term.

Unfortunately, the industry's traditional planning processes are not yet focused on identifying valuable transmission solutions that can address long-term uncertainties and reduce overall customer costs. In particular, as we have discussed in prior papers, much of today's regional planning processes need improvement and the interregional planning processes are largely ineffective at identifying valuable and cost-effective interregional transmission upgrades while anticipating the future needs of the individual regions and states. The industry consequently needs to develop improved regional and interregional transmission planning processes. These efforts need to start right away to fully realize the potential future savings for at least three reasons:

1. Transmission projects require at least 5–10 years to plan, develop, and construct; as a result, planning would have to start now to more cost-effectively meet the challenges of changing market fundamentals and the nation's public policy goals in the 2020–2030 timeframe;
2. A continued reliance on traditional transmission planning that is primarily focused on reliability needs will lead to piecemeal projects instead of developing integrated and flexible transmission solutions that enable the system to meet public policy goals more cost effectively; and
3. We are in the midst of an investment cycle to upgrade or replace the existing transmission infrastructure, mostly constructed in the 1960s and 70s; this provides unique opportunities to create a more modern and robust electricity grid at lower incremental costs and with more efficient use of existing rights-of-way for transmission.

A number of studies have shown that more “proactive” or “anticipatory” planning of the nation's regional and interregional transmission grid would reduce U.S. customers' overall electricity costs significantly. As summarized in this white paper, we estimate that the net savings associated with a proactive transmission planning and development process in the U.S. would range from (a) \$30–70 billion of savings in *total generation and transmission investment costs* through 2030 for compliance with current regulations to (b) \$47 billion/year of savings in *annual customer bills* under an even more environmentally-constrained future in which a well-planned grid significantly reduces generation investment and operating costs. These estimates are consistent with a range of U.S. and European studies showing that a robust interregional transmission system is critical to reducing the cost of achieving increasingly ambitious environmental policy goals.

In general, the overall cost savings associated with transmission investments are not solely a function of the stringency of environmental policy goals. As explained in our 2015 WIRES report, transmission provides a wide range of value to customers while reducing the costs of meeting public policy goals. Specifically, as we have explained previously and are reiterating here, the larger magnitude of the available cost savings should make it a top priority for state and federal policymakers to recognize that a robust and flexible transmission infrastructure enables cost-effective resource options for meeting customers' needs. As the industry transforms itself and as clean energy policies are implemented over time, a well-planned, flexible transmission infrastructure provides an "insurance policy" without which electricity customers will face higher risks of significant cost increases.

As federal and state energy regulators and policymakers face unprecedented challenges in the industry such as accelerated technological changes, shifting customer preferences, and new environmental regulations such as the CPP, they should urge transmission planners to move beyond today's traditional and mostly reliability-focused planning approaches. The industry needs to develop processes able to identify transmission solutions that increase future compliance flexibility while meeting anticipated environmental policy goals at lower costs and lower risks for customers.

I. Introduction and Background

The electricity industry is undergoing a significant transition toward a greater use of clean energy resources, away from high-emitting resources, and toward more market-based solutions to meet the load in utilities' franchised service territories. The stringency of environmental regulations has been increasing significantly at the local, state, and federal levels, limiting power plants' air emissions and their use of land and water. In addition, the evolving clean-energy mindsets of policymakers and customers have been, and will continue to be, to increase the use of renewable resources. The recent announcements by several cities in Texas—including Dallas, Austin, San Antonio, and Georgetown—to move to procuring 100% of their electricity from renewable resources, coupled with New York's and California's goals of 50% renewables by 2030, and Hawaii's goal to achieve a 100% RPS (Renewable Portfolio Standard) by 2050 shows the direction in which some parts of the electricity industry are heading. Against this backdrop of more ambitious renewable energy development goals, the Environmental Protection Agency's (EPA's) Clean Power Plan (CPP), whose final rule set in August of 2015 is currently "stayed" by the U.S. Supreme Court, is one of many drivers of a broader trend faced by the industry today.

To comply with the EPA's CPP standard, states would be required to submit State Implementation Plans that set out the approaches that the states choose to meet the standards. In all likelihood, those approaches would include a combination of implementing additional energy efficiency measures, reducing the generation from specific coal-based generating plants, constructing new lower-emitting generating plants, and importing power from non-emitting resources. If a state chooses not to submit a State Implementation Plan, the EPA has indicated that a default Federal Implementation Plan (FIP) would take effect. Along with other drivers, this EPA policy creates additional pressure to shift the country's future power generation mix. While the direction is clear, the magnitude and pace of the changes create substantial uncertainties for investors and utilities that must make the investments to serve customers.

Despite the dominance of CPP in recent U.S. environmental policy debates, it represents only part of the broader industry trends. And in some U.S. states, it is setting the direction, but not the pace of change. For instance, several states are moving well beyond the targets set out in the CPP and the governors of 17 states signed the "Accord for a New Energy Future" to deploy renewable, cleaner, and more efficient energy solutions in a cost effective way and to do so by modernizing the power grid.³

In addition to the CPP, the current industry trends include:

- Federal and state policies that have increased incentives for investments in renewable energy resources, both for utility-scale and distributed renewable generation resources;

³ Governors' Accord (2016).

- Significant cost reduction in solar energy and continued progress in wind generation technologies that similarly reduced their overall costs;
- Innovative project financing that takes advantage of investment incentives and technology cost reductions, yielding long-term purchased power agreements that are priced below \$25/MWh for wind generation and below \$40/MWh for solar generation;
- Significant reductions in natural gas prices, now one of the primary fuels for fossil-based electricity generation, that have substantially degraded the economic outlook of the existing fleet of coal and nuclear power plants and contributed to the retirement of many existing generating facilities;
- Increased stringency in other environmental regulations on air emissions, water usage, waste disposal, and land use for power plants;
- Shifting customer preferences for energy conservation and electricity from “green” resources;
- Reduced growth in electricity consumption triggered by, among other things, lower economic growth, new energy-efficient end-use technologies, customers’ increasing ability to conserve energy, increasingly stringent appliance and building codes, and regulatory requirements for electric utilities to implement energy efficiency and conservation programs to further encourage customers to reduce energy consumption;
- Increasing electrification of transportation; and
- Technological advances that allow customers and electric utilities to better monitor and control electricity usage.

While many of these factors are changing how customers use electricity, they create a significant shift in the relative economics of various generation technologies. Even without CPP, these trends will accelerate the retirement of coal-based generation and increase the demand for natural gas and renewable generation. While the pace and exact nature of this change are uncertain and highly dependent on federal, state, and local policies, the trend toward greater renewable resource development in the U.S. must be expected to continue due to significant further cost reductions and technological advancements.

As the industry shifts toward a much different future generation mix, federal and state policymakers and regulators will have a critical role in determining how transmission investments can best support their broader energy and environmental objectives, including a transition to a clean-energy future. Unfortunately, the current practice of focusing primarily on system reliability tends to steer policymakers and regulators away from paying attention to regional and interregional transmission planning approaches that can reduce risks and customer costs in the longer term. Thus, in this paper, we make the case that, when faced with a future that has a clear trend but significant uncertainties around the magnitude and timing of that change, a more proactively-planned transmission infrastructure can provide a much wider range of valuable options to cope with future challenges at lower risks and costs for customers and policymakers.

The flexibility and value that robust transmission can create is illustrated by the existing grid. Built mostly in the 1960s and 1970s, it offers substantially more benefits and uses today than could possibly have been envisioned when it was planned. Transmission provides insurance against the risks associated with future uncertainties. 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 state policymakers consider a variety of possible strategies for meeting future energy needs, CPP compliance, and other public policy objectives. Starting to identify and develop the right type and scale of transmission infrastructure options today is analogous to insuring ourselves against the risks of high-cost outcomes in the future.

II. The Need for Proactive Transmission Planning to Prepare for a Rapidly Changing and Increasingly Environmentally-Constrained Electricity Industry

Transmission is not explicitly discussed in EPA's CPP as an option to reduce compliance costs. Much of the CPP-related transmission planning discussion has been focused on maintaining a reliable power grid given the likelihood of additional coal plant retirements as a result of CPP implementation. While maintaining the reliability of the grid is critically important, the discussion has focused primarily on reliability. This tends to detract from the role that a more robust and flexible transmission grid can play in providing valuable options for reducing compliance costs.

Further, aside from the need to maintain system reliability, transmission is simply not a very prominent topic in most states' energy policy considerations, nor in the general conversation about the energy industry's transformation. If anything, regulators and policymakers have been focused more on reducing further increases of transmission-related costs. Such focus ignores the fact that transmission is one of the most critical components of developing a cost-effective, lower-emitting power industry. Energy and environmental policies that do not address how transmission affects total resource-related costs will be remiss in addressing the potential overarching impacts of the policies on the costs and risks faced by electricity customers.

Today's transmission planning efforts are focused primarily on maintaining a reliable electricity grid and are not typically considering impacts on total system-wide costs, including generation investment costs. As we showed in our 2015 WIRES report,⁴ these reliability-focused planning processes generally do not identify how transmission investments can reduce the initial cost of achieving public policy goals. They do not assess the risk that electricity consumers could face much higher costs in the absence of a well-planned and flexible grid that can deliver power from a diverse set of resources to customers in a future that differs significantly from the past in terms of resource diversity and geographical span.

⁴ See Pfeifenberger, Chang, and Sheilendranath (2015) (herein after 2015 WIRES Report).

To reduce the risks of high-cost outcomes requires a proactive approach to the planning of the regional and interregional transmission system that explicitly takes into account the uncertainties about future growth in energy use, fuel costs, technological changes, technology cost, shifts in supply and demand patterns, environmental regulations, and other state, regional, and federal policy goals. The effectiveness of such proactive planning has been used in some markets to overcome the traditional “chicken-and-egg” problem in planning for transmission upgrades and the renewable resources that rely on them. Examples of these investments include the transmission projects to access Competitive Renewable Energy Zones (CREZ) in Texas, the Tehachapi transmission network in California, the Integrated Transmission Plan projects in the Southwest Power Pool (SPP) and the Multi-Value Projects in the Midcontinent ISO (MISO). As described in more detail in Section III.A, despite the existing track record of how improved planning of the transmission grid can substantially support renewable resource development to meet public policy requirements at reduced overall costs (including generation-related investment costs), not much consideration has been given to the role of proactive transmission planning in the discussion of the available CPP compliance options.⁵ Because a more proactive planning process for transmission investments increases flexibility and creates options to develop lower-cost renewable resources, such an approach should be a critical element of any CPP compliance strategy. The power industry, and the electricity customers it serves, would be ill-served by delaying the planning of the necessary transmission infrastructure until the future of CPP or other policy goals is completely known and all other uncertainties are resolved.

Planning transmission more proactively is critical for at least three reasons:

1. Because transmission projects require 5–10 years to plan, develop, and construct, the industry must not delay to start planning the electricity grid of the next decade until there is complete clarity about current uncertainties. If the objective is to cost-effectively meet the nation’s public policy goals in the 2020–2030 timeframe, transmission planning for that future needs to start now. Given that CPP compliance deadlines likely will start in the early 2020s (even considering the current “stay” of the regulation by the U.S. Supreme Court), waiting until all uncertainties resolve themselves will foreclose important lower-cost compliance options that regional or interregional transmission solutions could provide.
2. Continued reliance on traditional transmission planning that is mostly focused on identifying reliability needs can lead to piecemeal solutions that foreclose the development of transmission options that ultimately offer lower costs and higher benefits to electricity customers. If the industry incrementally builds such piecemeal projects,

⁵ See WIRES (2014), recommending that “EPA move forward with a deeper appreciation of the likely impacts that the CPP will have on the high-voltage transmission system and, conversely, the risks and costs of ignoring the role of the high-voltage grid in bridging the gap between diverse, high quality, low carbon renewable resources and the bulk of electricity consumers, in relieving chronic and costly congestion of the power system, and in shifting the dispatch of natural gas-fired electric generation resources.”

valuable rights-of-way will not be used efficiently and we risk locking the industry into a future with sub-optimal infrastructure and higher overall costs. Given preexisting trends in market fundamentals and policy goals, most of the transmission options identified through such proactive planning will likely be valuable irrespective of CPP implementation.

3. Much of the U.S. electricity grid was built in the 1960s and 70s, which means we are now at the beginning of an investment cycle to replace and rebuild aging transmission facilities. This timing provides a unique opportunity to create a more robust electricity grid in a most cost-effective way and “right-size” the transmission infrastructure for more efficient use of the existing transmission corridors. Every initiative to replace and rebuild aging transmission facilities without considering more effective utilization of the existing right-of-way may be a lost opportunity to create a more robust, more flexible grid at lower costs than a system with piecemeal system additions.

Because of these factors, a “wait-and-see” approach to transmission planning may risk foreclosing the creation of lower-cost environmental compliance options and misses opportunities for lower-cost upgrades while rebuilding the aging existing transmission system. Policymakers and regulators consequently should be keenly interested in improving transmission planning that can identify system-wide cost savings under a wide range of futures that will evolve over time. Policymakers and regulators should advocate for conducting proactive planning and permitting of transmission projects even if conditions emerge that would ultimately allow them to defer some of the identified transmission projects. From a public policy perspective, conducting proactive planning processes is an important objective since the cost of such planning is small compared to the industry’s overall investment need and the potential savings that can be realized by identifying and developing more valuable and more flexible regional and interregional transmission solutions.

III. Interregional Transmission to Reduce the Cost of Meeting Evolving Environmental Policy Goals

Several regional planning groups—including MISO, SPP, and PJM—have shown that significant cost savings are achievable through improved regional planning, particularly when considering the cost of generation investments and operations. Nevertheless, despite these positive experiences, such improved regional planning practices are not applied to most transmission planning efforts. In particular interregional planning processes, including those put in place to comply with the Federal Energy Regulatory Commission’s (FERC’s) Order No. 1000, remain largely ineffective.⁶

From an environmental compliance planning perspective, identifying the lowest-cost compliance options is an important step that all policymakers and regulators ought to consider.

⁶ See, for example, 2015 WIRES Report, Section V and Appendix C.

Traditionally, utility-specific and even regional planning perspectives can be quite narrow in scope—only considering resources and system solutions available within a state—when a broader view could reveal attractive resource options and accompanying transmission solutions at a lower overall cost to customers. To achieve such a broader perspective, states (in complying with CPP and other goals and regulations) should consider more explicitly the costs of siting new resources both within and outside their local and regional borders, including those resources that would be accessible only through new interregional transmission investments.

As we summarize below, a wide range of recent industry studies have shown that more proactive regional and interregional planning can significantly reduce risks and the overall cost of meeting environmental policy goals.

A. STUDIES SHOW HOW TRANSMISSION INVESTMENTS CAN SIGNIFICANTLY REDUCE SYSTEM-WIDE COSTS, PARTICULARLY IN AN ENVIRONMENTALLY-CONSTRAINED FUTURE

A significant portion of the estimated savings from regional and interregional planning relate to the improved access to and integration of lower-cost renewable and clean resources, resulting in both generation capital cost savings and lower system operating and balancing costs. These renewable generation-related benefits are on top of other transmission-related benefits, which include improved reliability, reduced planning reserve margins needed to achieve resource adequacy requirements, increased wholesale market competition and liquidity, lower costs associated with transmission congestion and system losses, and reduced costs associated with challenging system conditions—such as during extreme weather or generation and transmission outage events.⁷

U.S. Studies

SPP recently completed a detailed retrospective analysis of the reliability, economic, and public policy benefits realized by a portfolio of 348 transmission projects constructed between 2012 and 2014 at a cost of \$3.4 billion. The main finding was that the overall ratio of benefits to costs associated with these investments is at least 3.5 to 1.⁸ The savings analyzed include those derived from fuel cost savings, reliability and resource adequacy benefits, generation capacity cost savings, reduced transmission losses, increased wheeling revenues that partly offset project costs, and public policy benefits associated with lower-cost wind development facilitated by the transmission upgrades.

Similarly, MISO's analyses of the projected benefits of its portfolio of Multi-Value Projects (MVPs) show that the broader regional transmission solution is expected to provide substantial value across the region while meeting local energy policy and reliability needs. In 2011, MISO's

⁷ See 2015 Wires Report and Chang, Pfeifenberger, and Hagerty (2013) (herein after 2013 WIRES Report).

⁸ SPP (2016).

board of directors approved the first MVP portfolio based on its projected ability to: (a) support a variety of state energy policies, specifically enabling the integration of over 40 million MWh/year of wind energy to meet the renewable energy mandates and goals of its member states; (b) maintain system reliability; and (c) provide economic benefits in excess of its costs under all scenarios studied, with benefit-to-cost ratios ranging from 1.6-to-1 to 2.8-to-1 for each zone within the MISO footprint.⁹ MISO evaluated the benefits of the same portfolio again in 2014 and found that the estimated value had increased, yielding benefit-to-cost ratios ranging from 2.6-to-1 to 3.9-to-1.¹⁰ As MISO reports, these savings consist of fuel cost savings, reduced operating reserves, reduced investment costs for both conventional and renewable generation, as well as reduced future transmission investments.

It is increasingly clear from the observable pricing of renewable energy contracts that the cost and quality of renewable generation varies substantially across regions. For instance, in some locations, the economics of certain renewable resources has become very attractive relative to conventional generation resources. Technological advances in the last decade have allowed the price of wind power contracts to fall below \$25/MWh in the Great Plains region of the country (net of the benefit of production tax credits)¹¹ and solar power contracts to be priced at less than \$40/MWh in Texas and the Southwestern U.S. (also net of the benefit of investment tax credits).¹² Developing the same resources in many other regions of the U.S. can cost twice as much or more per MWh.

Based on U.S. Energy Information Administration (EIA) projections and our own research, approximately 130,000 MW of additional renewable generation investments likely would still be needed to meet existing RPS-related needs and for CPP compliance through 2030 assuming a 30% capacity factor for the renewable resources used to meet the need.¹³ However in some of lowest-cost regions of the country, renewable resources, such as wind generation in the Great Plains, can reach average capacity factors of 40% to 50% using the most modern technologies.¹⁴ With a 40% capacity factor for incremental wind generation, the renewable resource need would only 100,000 MW. At a 50% capacity factor (or even higher) in the windiest areas of the country, the renewable resource need would be reduced to 80,000 MW. With the wind generation in the windiest regions of the country enjoying a 10% to 20% capacity factor

⁹ See MISO (2015)

¹⁰ MISO (2014b).

¹¹ See U.S.DOE (2015)

¹² Carr (2015). See also, Copley (2016), noting 20-year solar power purchase agreements signed in Nevada with a first-year prices of \$38.70/MWh.

¹³ The U.S. Energy Information Administration (EIA) (2015) estimated that the CPP compliance base case for 2030 generates about 1.1 trillion kWh from renewables (25% of 4.5 trillion kWh); in contrast the reference case for 2030 generates about 0.75 trillion kWh from renewables (16% of 4.75 trillion kWh). The 0.35 trillion kWh difference (350 million MWh) of renewable generation with a 30% capacity factor will require approximately 130,000 MW of renewable resources.

¹⁴ Wisner and Bolinger (2015), page 44, Figure 36.

advantage over renewable resources located closer to load centers, and with an assumed investment cost of \$1,500 per kW of installed wind generating capacity, this advantage translates to capital cost savings of between \$50 billion to \$80 billion. If integrating the more distant wind resources requires additional transmission investments of approximately \$300/kW of installed wind generating capacity (*e.g.*, \$600/kW-wind to integrate distant resources vs. \$300/kW to integrate more local resources), the additional cost of transmission to integrate the lower-cost wind resources would be in the range of \$10–\$20 billion. Overall, spending \$10–\$20 billion more on transmission to save \$50–\$80 billion in generation-related costs would reduce the net cost of complying with existing RPS- and CPP-related investment needs by \$30 billion to \$70 billion.

The fact that more proactive planning of the nation’s regional and interregional transmission grid can facilitate such cost savings has been estimated in a study prepared by a consortium of five universities for the Eastern Interconnection States Planning Council (EISPC), National Association of Regulatory Utility Commissioners (NARUC), and the Department of Energy (DOE). The EISPC study shows that traditional planning approaches are no longer adequate to achieve least-cost outcomes in light of challenges such as plant retirements, renewable generation integration, and increasingly stringent environmental regulations that lead to significantly more complex and less predictable power systems.¹⁵ The study analyzed interregional transmission needs in the Eastern Interconnection of the U.S. under the traditional transmission planning approach (with transmission built in response to generation investment decisions) and under an “anticipatory planning” approach that co-optimized transmission and generation investment, taking into considerations key uncertainties such as carbon costs, load growth, fuel prices, and renewable generation levels. While we recognize that such co-optimized investments are difficult to achieve in markets where utilities and planners no longer have the full responsibility of integrated planning for generation and transmission, anticipatory planning that takes into account scenarios that cover the likely range of future trends and uncertainties will be able to achieve similarly co-optimized results. The EISPC study results show that, compared to what would be spent under traditional planning approaches, anticipatory transmission planning would reduce total generation costs by \$150 billion, while increasing interregional transmission investments by \$60 billion, with an overall savings of \$90 billion system-wide. Of the \$150 billion in generation-related cost savings, 40% relate to generation *investment* costs that are not typically considered in traditional transmission planning efforts because the traditional planning efforts mostly focus on savings related to fuel and other variable cost of generation (so-called “production costs savings”).

The anticipatory planning framework applied in the EISPC Co-Optimization Study was also applied to the Western Electricity Coordinating Council (WECC). In “Planning Transmission for Uncertainty: Applications and Lessons for the Western Interconnection,” the authors apply a scenario-based model to co-optimize transmission and generation investment under

¹⁵ EISPC (2013).

uncertainty.¹⁶ The model considers two transmission investment periods: (1) near-term investments in years 1 through 10; and (2) longer-term investments in years 11 through 20. The study explored the questions of whether, when compared to traditional planning approaches, optimized planning under uncertainty would delay near-term investment until more is known about the future, or invest in more near-term transmission so that the system is better positioned to respond to future challenges and drivers earlier. The study results show that optimized proactive transmission planning under uncertainty would increase near-term investment by an average of 20% to 50% compared to traditional planning approaches. While it is perhaps counter-intuitive that proactive investment is more valuable than waiting, the analysis demonstrated that the earlier transmission investments provide additional options to adapt to future market conditions at lower total cost. These options may include, for example, the ability to expand transmission capability quickly and cost-effectively because single circuit lines were constructed on double-circuit towers. The options may include access to regions with a variety of generation resources types to insure lower-cost outcomes if the relative cost of the different resource types changes in the future. The EISPC WECC study estimates that overall cost savings range from \$1 billion to \$28 billion, depending on specific future outcomes and the planning assumptions used in the traditional planning approach. The study shows that its results are robust across different future scenarios, and concludes that considering a range of possible futures is more important than the number or precise types of scenarios used in the analysis.

A separate study on the need for interregional transmission projects to meet the nation's increasingly ambitious environmental goals was conducted by the Eastern Interconnection Planning Collaborative (EIPC). The results of EIPC's Phase 1 analysis show that an efficient interregional transmission planning approach to meeting a more ambitious 25% nation-wide RPS standard would reduce generation costs by \$163–197 billion compared with using traditional planning approaches.¹⁷ The EIPC's Phase 2 analysis estimates that the transmission investments needed to support the generation and the environmental compliance scenarios associated with these generation-related savings range from \$67 to 98 billion.¹⁸ Taken together, these results indicate that the combination of interregional environmental policy compliance and interregional transmission may offer net savings of up to \$100 billion in a future with stringent environmental policy goals.

A 2016 analysis by the University of Colorado and the National Oceanic and Atmospheric Administration (NOAA) estimated that a more robust interregional transmission grid would allow the U.S. to reduce its carbon emissions by 80% relative to 1990 levels without an increase in (inflation-adjusted) electricity rates.¹⁹ The NOAA study estimates that such emission reduction could be achieved cost effectively with a more robust interregional transmission grid, which would save U.S. electricity consumers \$47 billion annually at a benefit-to-cost ratio of

¹⁶ Ho, Hobbs, Donohoo-Vallett, *et al.* (2016).

¹⁷ EIPC (2011).

¹⁸ EIPC (2015).

¹⁹ MacDonald, Clack, *et al.* (2016).

almost 3-to-1. The study analyzes the potential impact on co-optimizing generation dispatch, generation expansion, and transmission investments—allowing for cost savings from geographic diversity, load and weather diversity, and reserve pooling on a nation-wide, interregional basis. The resulting resource development is a highly geographically-diversified mix of conventional and renewable resources, ranging from off-shore wind generation in the eastern U.S., to new onshore wind, solar PV, natural gas, nuclear, and hydroelectric plants developed throughout the U.S.

European Studies

The European experience with a transition to a lower-emitting electricity industry provides useful insights to the U.S. because the transition has started much earlier in Europe than in the U.S. For example, as of 2015, generation from renewable resources supplied more than 30% of the annual power consumption in Germany, with an hourly maximum of 83.2% from renewable generation reached on August 23, 2015.²⁰ With similarly high levels of renewable generation in Denmark and Spain, the European countries have been actively preparing and planning for significant further reductions in carbon emissions from power plants. For example, Germany is currently targeting a 35% renewable generation share by 2020 and 50% by 2030. In this context, several recent studies have analyzed the role of transmission investments in supporting Europe's environmental and clean-energy policy objectives. These studies uniformly reached the conclusion that significant transmission investment is necessary to reduce the overall cost of this transition. In addition, as described in more detail below, increasing the share of distributed generation, while potentially reducing distribution investment needs, does not significantly affect the optimal size of the regional and interregional transmission grid.

The *European E-Highway 2050* study found that interregional transmission investments significantly reduce the cost of achieving a low-carbon electricity sector by facilitating the integration and diversification of lower-cost renewable resources region-wide (compared to primarily using higher-cost local renewable resources to achieve the carbon emission reduction goals).²¹ The study concluded that, in high-renewable generation scenarios, interregional transmission investments are highly cost effective with a payback period of just one year. The study explains that the high cost savings are the result of: (1) the highly fluctuating generation profiles of the renewable resources that can be balanced more cost effectively throughout Europe if the grid can support the regional and interregional power exchanges; and (2) the lower costs of generation from renewables that displace thermal dispatch. Even in the scenarios with a high deployment of distributed generation, significant transmission investments are cost effective. The study analyzed five divergent scenarios of future market conditions and found, despite the large differences in the assumptions across the five scenarios, transmission investments consistently were cost effective between Scandinavia and northern continental Europe, between

²⁰ Graichen, Kleiner, and Podewils (2016).

²¹ E-Highway 2050 (2015).

Finland and Poland through the Baltic states, between the U.K. and Spain through France, and between Greece and Italy.

In a separate report, the *Integration of Renewable Energy in Europe*, published in 2014, the authors found that the most cost-effective path to achieving Europe's overall renewable energy policy objectives requires a substantial expansion of its transmission networks along with conventional (backup) generation.²² The study estimated that transmission will represent approximately 15% to 20% of total investment needs across all scenarios. While these transmission investments become increasingly important to support the integration of higher levels of renewable generation, their ability to increase system flexibility and security of supply through the exchange of energy between regional markets is equally important as they reduce the overall amount of conventional generation required in the system, thereby further reducing system-wide costs. The study found that a delay in (or the absence of) regional and interregional transmission investments increases the overall system-wide costs and results in more extreme levels of price volatility within the regional markets.

An earlier study, *Transformation of Europe's Power System Until 2050*, prepared by McKinsey in 2010, had found that the most cost-effective way to reach 40–45% renewable generation targets for 2050 in Europe would require a doubling of existing region-wide transmission capabilities by 2020 and an almost fourfold increase in transmission capabilities by 2050.²³ That study found that, if Germany were to continue to meet its emissions and renewable energy goals through mostly local generation investments, this approach would be 30–35% more expensive than achieving the same goal through Europe-wide coordination. To make Europe-wide coordinated resource planning possible, however, would require Germany to significantly expand its interregional transmission capabilities with the rest of Europe.

B. THE IMPACT OF DISTRIBUTED GENERATION ON THE NEED FOR AND VALUE OF REGIONAL AND INTERREGIONAL TRANSMISSION

Increased deployment of distributed solar generation in many U.S. regions is a reflection of electricity users capitalizing on the decreasing cost of solar generation and the various state and federal incentives available to support it. Much of the fast expansion of distributed solar generation is driven by net metering policies and innovative financing from the companies that develop the distributed solar generation. The available experience and industry studies in Europe suggest that a more significant development of distributed renewable generation can reduce distribution investment needs but would not significantly reduce overall transmission needs, nor diminish the benefits of a more robust regional and interregional transmission grid.

Integration of both distributed and utility-scale renewable generation represents a key pillar of Europe's broader energy and climate objectives in reducing emissions, ensuring security of supply, diversifying energy supplies, and improving Europe's industrial competitiveness. This

²² DNV GL – Energy (2014).

²³ McKinsey & Company (2010).

raises the important question of how higher shares of distributed renewable generation affects infrastructure need and overall costs—one that has been studied extensively in Europe. Turning again to European experience to help North America anticipate future needs, we can project how the integration of a large amount of distributed renewable generation will likely affect infrastructure needs and overall costs.

For example, most of Germany’s solar power generation is associated with distributed roof-top solar installations in southern Germany, while most of Germany’s wind generation is located in northern Germany and the North Sea. These locational differences have created substantial north-south power flows through Germany and its neighboring countries.²⁴ Traditionally, Germany’s ability to accommodate such significant amounts of renewable generation has been attributed to two main factors:²⁵ (1) the strength of its existing power grid; and (2) flexible operation of coal, nuclear, gas, and pumped hydro plants. However, despite these strengths, significant transmission expansion is needed to integrate renewable generation in a cost effective manner. Since 2011, the German national regulator BNetzA has been required to conduct annual transmission planning analyses that incorporate projections of where renewables will likely be developed over the next ten years. As a result, an additional three north-south transmission lines are being developed as part of this planning process. The German experience shows that concurrent planning for generation and transmission is needed to reduce the cost of a clean energy future even with substantial reliance on distributed generation.

Similarly, and perhaps unexpectedly, the 2014 report on *Integration of Renewable Energy in Europe*²⁶ found that the choice between centralized, utility-scale generation and distributed generation does not have a direct impact on transmission needs. Instead, transmission needs are driven mainly by the type and regional distribution of renewable generation resources on a European-wide level (rather than the choice between centralized and distributed generation within a given region). The study found that an increased share of distributed generation can reduce distribution system investment needs if the distributed resources can be controlled (*e.g.*, curtailed and/or voltage regulated) by the system operator. (More distribution investment would be needed if the distributed resources cannot be controlled.) Overall, while a larger reliance on distributed renewable generation can reduce the need for distribution investments, transmission needs do not decline with greater reliance on distributed renewables.

C. LESSONS GAINED FROM U.S. AND EUROPEAN STUDIES ABOUT THE OUTCOMES OF PROACTIVE TRANSMISSION PLANNING

As described above, the research on anticipatory transmission planning (often referred to as “probabilistic transmission planning” or “transmission planning under uncertainty”) shows that proactive planning of transmission investments can reduce overall costs as well as the risk of

²⁴ See, for example, Ratz (2012).

²⁵ Martinot (2015).

²⁶ DNV GL – Energy (2014).

encountering high-cost future outcomes related to changes in regulatory policies, fuel costs, loads, and technologies.²⁷ The studies show that anticipatory planning that co-optimizes the transmission and generation buildout considering uncertainties yields a mix of generation and transmission investments that are quite different from those that would be the result of traditional, more deterministic transmission planning approaches. The studies point to several noteworthy differences.

The first main difference between the two approaches of planning is that anticipatory planning results in more regional and interregional transmission investments at lower total system-wide costs. Second, generation capital cost savings (not considered in most traditional transmission planning processes) are a major source of the benefits of a more robust transmission system. This conclusion is consistent with the fact that transmission costs account for approximately 10% of average retail customer bills but greatly influence generation-related costs, which account for approximately 50% of customer bills. While investment in transmission infrastructure comes at a cost, the studies described above consistently show that the sum of transmission-related benefits can significantly exceed that cost.

Third, the more explicit consideration of future uncertainties in the planning process yields a more cost-effective, phased-in buildout of the system that provides more flexibility to adjust plans over time. This is intuitive because it is valuable to have the option and flexibility to quickly adjust plans as the electricity system, market structure, and policies evolve. Constructing a single circuit line on double circuit towers (as was done for the CREZ buildout in Texas) or constructing a higher voltage line but operating it at lower voltage levels are examples of ways to create low-cost options that are valuable in the presence of uncertainty.

Finally, the studies show that uncertainties around future renewable technologies and their relative costs will affect the best locations and sizes of the interregional transmission investments. For example, if wind generation remains the lower-cost option, the most valuable interregional transmission will be to expand the grid from wind-rich areas of the Great Plains towards load centers to the east and west of the wind-rich areas. This may include expanding transmission from Wyoming westward, and expanding the system eastward from MISO North, SPP North, and SPP South.

Likewise, if solar generation costs continue to decline, as currently anticipated, more of the most valuable interregional transmission investments will be located in solar resource-rich areas, such as the southern parts of the country. This includes in particular areas from the Desert Southwest to southern portions of California and the rest of the West. Similarly system expansions in the Electric Reliability Council of Texas (ERCOT), southern SPP, southern MISO, and SERC will become more valuable and would reduce the cost of meeting the increasingly more ambitious clean energy goals and mandates.

²⁷ In addition to the research on probabilistic transmission planning discussed above, see: Park and Baldick (2013); Munoz, Hobbs, *et al.* (2013); Van Der Weijde and Hobbs (2012).

Irrespective of the requirements set out in the CPP and other environmental regulations, the decreasing cost of wind and solar generation resources and existing trends in renewable energy and environmental policies will require careful evaluations of potentially high-value regional and interregional transmission projects that allow states to realize the greatest value from available regional renewable resources and interregional resource diversity. Interconnecting solar and wind generation across regions decreases the operating cost of balancing the resources within each region. Diversifying intermittent renewable generation output across regions will increase the capacity value of renewable generation during peak load conditions and thereby reduce the amount of conventional generation capacity that will be needed to ensure resource adequacy.

Given the trend toward clean energy resources while the industry faces significant uncertainties around the specific timing and magnitude of the policy mandates and customer preferences, proactive transmission planning requires going beyond the “base case” or “business as usual” analyses that heavily rely on the traditional planning processes. As the reviewed industry studies show, proactive planning must more explicitly consider a range of plausible future scenarios beyond the near-term planning horizon to evaluate how the grid should be built to be able to adapt to any one of these futures over the long-term. Because generation investment options are a function of transmission availability, it is necessary to consider how both generation capital costs and operating expenses are affected by transmission investments over the long-term.

IV. A Robust Transmission Infrastructure Offers a Broad Range of Benefits and Cost Mitigation Options Beyond Addressing Environmental Policies

The types of interregional transmission investments discussed above can reduce the cost of achieving state and federal policy objectives even further when one recognizes that the cost savings associated with accessing lower-cost renewable generation sources are accompanied by the additional economic value that transmission investments can provide to regions, including benefits associated with the diversity of load patterns across larger footprints and multiple regions. For example, more strongly interconnecting the Southwestern U.S., the southern portion of SPP, and ERCOT—regions all rich in both solar and wind resources—would yield significant additional value in diversifying both intermittent generation and load variances across the three regions and beyond. This means that, even if some states do not expect to move in the direction of deploying more clean energy resources, transmission investments that enlarge regional footprints can reduce generation capacity needs by capturing load diversity and improving the access to and the use of existing generation.

Interregional transmission expansions can be particularly valuable in light of the divergence in load patterns across regions that would facilitate generation investment savings. For example, MISO in its HVDC Network Concept study shows that expanding east-to-west and north-to-south transmission interties between regions offers load diversity benefits that would reduce generation capacity needs by 36,000 MW nation-wide with investment cost savings of

\$38 billion.²⁸ In addition, MISO estimated that interconnecting the nation's power markets more strongly would reduce the cost of balancing area operations (including operating and load following reserves) by \$12 billion in net present value terms. Since it is a conceptual nationwide HVDC transmission network study, MISO does not yet include an estimate of transmission costs associated with achieving the identified savings. However, it is clear that benefits related to load diversity and improved interconnections between power markets are only a portion of the overall benefits of such a network; these other benefits need to be considered when evaluating the cost effectiveness of interregional transmission projects. For example, MISO's conceptual east-to-west and north-to-south HVDC transmission interties between regions to capture the \$38 billion value of interregional load diversity are largely the same transmission infrastructure that would be needed to access and integrate some of the Nation's lowest-cost renewable generation.

Separately, MISO's Value Proposition report estimates that the load diversity benefits already realized through MISO's existing regional transmission grid *currently* reduces the generation capacity needed across the MISO footprint by approximately 11,000 MW (roughly 6% of total currently installed capacity), which in turn provides between \$1.3 billion and \$1.9 billion in *annual* cost savings to the region.²⁹ Simultaneously, MISO estimates that the same transmission investments created annual benefits of approximately \$350 million/year through improved access to low-cost renewable resources.

As part of the MISO HVDC Network Concept study, MISO highlights that there is significant value in increasing the linkages between the Eastern and Western Interconnections. Replacing the aging back-to-back HVDC converter stations that currently provide the only links between the Eastern and Western Interconnections may be a unique opportunity to increase their transfer capabilities,³⁰ which would help capture the diversity of load, wind, and solar resources on either side of the interconnections' boundary.³¹ The same resource adequacy and generation cost benefits would likely be realized by interconnecting ERCOT more strongly with the rest of the country.

²⁸ MISO (2014a).

²⁹ MISO (2016).

³⁰ On January 14th DOE announced its approval of a Grid Modernization Laboratory Consortium study. Led by NREL, "Project 16" will "convene industry and academic experts in power systems to evaluate" in 2016 and 2017 "the HVDC and AC transmission seams between the U.S. interconnections and propose upgrades to existing facilities that reduce the cost of modernizing the nation's power system." This two-year collaborative study—involving the owners of the HVDC converter stations, affected transmission owners, and regional planners—hopes to inform effective interregional grid planning beyond the mandates of FERC Order No. 1000, which are limited to regional and interregional planning within each of the existing interconnections. U.S.DOE (2016).

³¹ For example, a University of Wyoming study on wind diversity between California and Wyoming found that 6,000 MW gigawatts of wind split evenly between Wyoming and California (compared to locating the wind generation only in California) produces annual savings in the \$100 million range for California ratepayers from reduced payments for "dispatchable" or make-up power. University of Wyoming (2013).

Planning transmission across the nation’s regional power market boundaries will necessitate a paradigm shift beyond the current regionally-focused planning practices. Despite the requirement of FERC Order No. 1000 to coordinate interregional planning, most of today’s transmission planning activities remain focused on a region-internal and utility-specific basis. As we have shown in our prior work, today’s interregional planning processes are largely ineffective and generally unable to identify valuable transmission investments that would benefit two or more regions.³²

To be more effective in identifying valuable transmission investments that can reduce the system-wide costs paid by customers requires that regional and interregional planning processes take into account the broad range of economic and risk mitigation benefits provided by a more robust and more flexible transmission grid. As we have discussed in both the 2013 and 2015 WIRES Reports, these benefits include:

- A well-planned transmission grid provides more flexibility by allowing more generation resources to be built in the lowest-cost locations (while considering other cost tradeoffs such as availability of fuel or natural resource and land access). An example is the many combined-cycle gas turbine plants that are being developed in PJM’s shale-gas regions (offering lower-cost fuel) with ready access to PJM’s 500 kV backbone transmission grid.
- A flexible grid reduces the often high costs associated with both planned and unplanned transmission outages (for both new construction and maintenance).
- A robust system can provide insurance value by being able to address the challenges related to extreme weather or other unpredictable events such as storms, floods, droughts, and wildfires.
- Transmission expansion creates valuable trading opportunities across existing regional and interregional constraints. For example, at existing wholesale power price differences between SPP and the Northwestern U.S., adding 1,000 MW of transmission capability would create approximately \$3 billion in economic benefits on a present value basis.³³

We have found that the value of flexibility is not typically captured by traditional transmission planning processes that focus on meeting needs mostly for a “base-case” or “business-as-usual case.” At times, even if certain scenarios are considered in the planning studies, the decision to develop projects can remain heavily focused on the limited definition of “economic benefits” that are estimated only for the “base-case” assumptions. This approach will reject even very valuable transmission investments.

³² For a review of the current practices associated with interregional transmission planning, the significant gaps and barriers that prevent the identification and evaluation of beneficial interregional transmission projects, and options to address interregional planning deficiencies, see 2015 Wires Report.

³³ In recent years, the difference in hourly prices between SPP-North and the Pacific Northwest exceeded \$10/MWh during 67% of all hours, with a \$22/MWh average of (absolute) hourly differences.

For example, the California ISO's (CAISO's) 2004 study of the Palo Verde to Devers No. 2 (PVD2) line illustrates how a sole focus on base case results fails to identify the true value of transmission projects.³⁴ The CAISO's simulations of base-case conditions estimated production cost savings of \$55 million per year associated with the PVD2 project. Considering that the annualized cost of transmission was estimated to be \$71 million, most traditional planning processes would have rejected the project as uneconomic because the estimated "production cost savings" under base-case conditions do not exceed the cost of the project. However, when considering benefits beyond production cost savings, the estimate of total cost savings increased to \$100 million per year even for the base-case assumptions.

Considering a broader set of benefits and going beyond base-case assumptions identifies additional value. By considering the probability of infrequent but high-cost events that could occur in the future, the probability-weighted average savings associated with the PVD2 project increased to \$120 million per year. This probability-weighted average calculation still understates the substantial higher cost savings that the project was estimated to provide under the most challenging market conditions. For instance, the CAISO's study found that, without the proposed line, there was a 10% chance that the annual system-wide cost would be at least \$300 million (and possibly up to \$750 million) higher without PVD2. The high end of this cost range is associated with a long-term outage of the SONGS nuclear station, which (although a reality today) was considered to be a very unlikely, extreme contingency in this 2004 study. This California example demonstrates the importance of "insurance value" by showing that, under certain circumstances, the cost savings offered by transmission investments can substantially exceed "base case" savings. A least-regrets planning approach would need to consider the much higher costs that could be incurred if the project was not developed.

V. Transmission Planning Under Uncertainty

A frequently-voiced concern is that effective transmission planning is not possible until key uncertainties are resolved and it is clear what specific environmental requirements and other assumptions need to be considered in the planning process. This concern has effectively stalled regional and interregional planning processes. However, delaying long-term planning because the future is uncertain will necessarily limit transmission upgrades to those that address only the most urgent near-term needs, such as reliability violations. Such a focus on near-term reliability needs would result in missed opportunities to capture higher values through investments that could address longer-term needs more cost effectively. The near-term focus would lead to the inefficient use of scarce transmission corridors and rights-of-way.

While most of today's planning processes are not yet designed to support proactive planning efforts that explicitly take uncertainties into consideration, experience with "planning under uncertainty" exists in other industries. For example, the oil and gas industry has long used

³⁴ See 2015 WIRES Report, Section III.B and Appendix A.

scenario-based long-term planning to deal with such uncertainties.³⁵ Some utilities have begun to adopt scenario-based strategic planning and resource planning processes to develop robust plans under uncertainty. We recommend that transmission planners evaluate long-term uncertainties through similar scenario-based analyses covering at least the next 10 years in terms of defining future uncertainties and scenarios and use 20–40 years for the valuation time horizon (for purpose of present value calculations).³⁶

The research studies performed for EISPC and WECC (as discussed earlier) specifically applied scenario-based models to co-optimize transmission and generation investment under uncertainty.³⁷ As we noted in our earlier work,³⁸ scenario-based planning processes have been employed in some RTO and other transmission and resource planning efforts. For example, the Tennessee Valley Authority has been using a scenario-based, least-regrets planning framework extensively in the development of its integrated resource plans.³⁹ The Indiana Utility Regulatory Commission has encouraged the utilities, in collaboration with their stakeholders, to develop scenarios and sensitivities that analyze a likely future “base case,” and stress the system by exploring lower probability scenarios and sensitivities that have a high potential cost if realized.⁴⁰

A long-term, scenario-based transmission planning study was presented to the Public Service Commission of Wisconsin by American Transmission Company (ATC) in 2007. In its Planning Analysis of the Paddock-Rockdale Project, ATC evaluated the benefit that the project would provide under seven plausible futures.⁴¹ That ATC study, which evaluated a wide range of transmission-related benefits, found that while the 40-year present value of the project’s customer benefits fell short of the \$136 million present value of the project’s revenue requirement in the “Slow Growth” future, the present value of the potential benefits substantially exceeded the costs in other futures scenarios analyzed. The net benefits in the other six futures span a wide range, from approximately \$100 million under the “High Environmental” future, to approximately \$400 million under the “Robust Economy” and “High Wisconsin Growth” futures, and reaching up to approximately \$700 million under the “Fuel Supply Disruption” and “High Plant Retirements” futures. The others scenarios showed that *not* investing in the project could leave customers as much as \$700 million worse off. Overall, the Paddock-Rockdale analysis shows that understanding the potential impact of projects across

³⁵ For example, see Royal Dutch Shell (2013). See also Wilkinson and Kupers (2013).

³⁶ Even if scenarios are defined only for a 10–20 year time horizon, it is important to recognize that investment with a useful life of 40–50 years will not be worthless after the first 20 years of operations. To estimate the value after the 20-year scenario horizon, analysts typically assume that benefits in year 20 would continue (possibly with prevailing trends) for the remaining life of the assets.

³⁷ Ho, Hobbs, Donohoo-Vallett, *et al.* (2016).

³⁸ See 2015 WIRES report.

³⁹ See TVA (2015).

⁴⁰ Borum (2015).

⁴¹ ATC (2007), p. 5.

plausible futures is necessary for transmission planning under uncertainties and for assessing the long-term risk mitigation benefit of a more robust, more flexible transmission grid.

In its most recent long-term transmission study, ERCOT implemented a stakeholder-driven long-term transmission planning process that applied a scenario-based planning framework to identify the key trends, uncertainties, and drivers of long-term transmission needs in ERCOT. The process involved representatives from a broad set of ERCOT stakeholder groups to develop a range of internally-consistent scenarios covering plausible future market conditions.⁴² ERCOT converted the detailed scenario descriptions (developed jointly by stakeholders) into transmission planning assumptions and generation investment and retirement projections that are consistent with each scenario's projected long-term market and regulatory conditions. Scenarios differed in their projections for load growth, environmental regulations, generation technology options/costs, oil and gas prices, transmission regulations and policies, resource adequacy, end-use markets, and weather and water conditions. Following that, ERCOT performed initial planning analyses for ten scenarios—including projections of likely locations and magnitudes of generation investments and retirements—and identified four scenarios that covered the most distinct range of possible futures to carry forward for detailed long-term system modeling analyses.

Evaluating long-term uncertainties through various distinctive scenarios that bound plausible futures is an effective planning approach given the long useful life of new transmission facilities that can exceed four or five decades. Uncertainties about future regulations, industry structure, or generation technology (and associated investments and retirements) can substantially alter the need and size of future transmission projects. Results from scenario-based analyses of these long-term uncertainties should be used to:

1. Analyze the likely range of transmission-investment drivers such as load growth and location-specific generation investments and retirements;
2. Identify “least-regrets” projects that simultaneously (a) mitigate the risk of very high-cost outcomes that are possible in some futures and (b) provide value that is robust across most futures;⁴³ and
3. Identify and evaluate projects (such as building a single circuit line on double circuit towers)⁴⁴ to create valuable options that can be exercised in the future depending on how the industry actually evolves and uncertainties are resolved.

As done in ERCOT, structuring the scenarios development effort to create plausible and reasonable scenarios about future market conditions should involve relevant stakeholders' participation and input because the results of planning studies will be more readily accepted by

⁴² ERCOT (2014); see also Chang, Pfeifenberger, and Hagerty (2014).

⁴³ For a more formal approach to “least regrets” planning, see Bean and Hoppock (2013). See also, TVA (2014).

⁴⁴ For example, ERCOT's transmission planning efforts routinely employ this option.

stakeholders or regulators if they understand the assumptions embodied in the scenarios or if they believe that the scenarios reflect a reasonably complete range of plausible future market conditions. To further improve the understanding and buy-in of long-term planning efforts, this process should be defined clearly from the onset, including specifying concisely how scenarios will be used in transmission planning efforts.⁴⁵ The identification and valuation of transmission projects to create options that can (but need not) be exercised in the future requires a multi-stage planning process that evaluates discrete decision points across the scenarios as uncertainties get resolved. Such multi-stage, scenario-based planning processes allow transmission planners to anticipate and proactively evaluate how siting and operating decisions by investors in generation and other resources will likely be affected by the availability of transmission resources.⁴⁶

VI. Conclusions

The power industry is undergoing a transition to a more extensive use of clean-energy resources while facing uncertainties in the magnitude and timing of those changes. These uncertainties relate to how customers will want to use electricity, the relative costs of different generation technologies, the subsidies and programs provided to different generation technologies, changes in fuel prices, and the variety of environmental policies and regulations at the local, state, and federal levels. Because the development of transmission takes at least five to ten years, the industry cannot wait to start planning for these needs until the uncertainties resolve themselves. Taking a “wait-and-see” approach would foreclose the development of lower-cost options for meeting the challenges and more ambitious policy goals that will invariably be faced by the industry over the course of the next decade. To address the future uncertainties and face the policy challenges more proactively, policymakers and regulators must engage now in evaluating the critical role that transmission investments can play in mitigating the risks of high-cost future outcomes and in reducing the overall cost of electricity to customers.

As we move forward with addressing the challenges of a rapidly changing industry and increasingly ambitious environmental objectives, policymakers and regulators should ask the utility and regional planners to undertake a careful assessment of how transmission can reduce the cost of compliance with these regulations. Such careful assessment should include using scenario-based long-term planning, taking into consideration many of the trends and uncertainties described above. Considering coal plant retirements and integrating new renewable energy resources onto the grid in light of the current uncertainties will require a flexible and robust transmission infrastructure. In particular, regional and interregional transmission infrastructure plays a critical role as it can simultaneously improve system reliability, reduce generation capital investment costs, and integrate a diverse set of lower-cost renewable resources. Thus, having a robust and flexible regional and interregional transmission

⁴⁵ See Appendix B of 2015 WIRES Report. See also Chang and Pfeifenberger (2016).

⁴⁶ See Ho, Hobbs, Donohoo-Vallett, *et al.* (2016).

infrastructure will become a critical component to lower the overall cost of the U.S. states' environmental and energy policy strategies.

Simply looking at renewable energy resource maps for North America shows where the most cost-effective renewable energy resources can be captured and integrated. Many cities and states across North America have announced their commitment to increase their reliance on renewable energy resources. Thus, even without the requirements set by EPA's CPP, building a robust grid that ensures reliability while facilitating the integration of low-cost renewable resources will need to be a part of the path forward. Even in areas where distributed generation has begun to provide a significant portion of individual customer's electricity needs, the European experience shows that transmission infrastructure will continue to be needed to compensate for the intermittency of these resources and to help balance the broader regional electricity system.

Transmission planning for a clean energy future must begin now if policymakers want to avail themselves of lower-cost compliance options and reduce the risks to customers posed by high-cost futures and piecemeal transmission solutions that would involve higher costs over the long term. Improving and, in some instances, overhauling the way transmission is planned is necessary to address the challenge of incorporating more clean energy into our future. To capture the low cost opportunities, states and regions will need to collaborate more actively. Active collaboration will include joint planning and cost sharing of interregional transmission infrastructure that can make the significant benefits accessible to a wider range of states and beyond the existing regional boundaries. This collaboration will need to go well beyond the current practice of exchanging planning data, agreeing on transmission benefit metrics, and the sharing of planning assumptions and project proposals as required under FERC Order No. 1000. It will require regional planners and policymakers to develop actionable interregional transmission plans that recognize the benefits of a more robust interregional grid to facilitate the development of a more diverse and lower-cost set of resources that provide valuable compliance options under a wide range of future states of the bulk power industry.

List of Acronyms

AC	Alternating Current
ATC	American Transmission Company
CAISO	California Independent System Operator
CEO	Chief Executive Officer
CPP	Clean Power Plan
CREZ	Competitive Renewable Energy Zone
DOE	Department of Energy
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States Planning Council
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
HVDC	High-Voltage, Direct Current
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
kV	Kilovolt
kW	Kilowatt
MISO	Midcontinent Independent System Operator
MVP	Multi-Value Project
MW	Megawatt
MWh	Megawatt Hours
NARUC	National Association of Regulatory Utility Commissioners
NOAA	National Oceanic and Atmospheric Administration
PPA	Purchase Power Agreement
PJM	PJM Interconnection
PV	Photovoltaic
PVD2	Palo Verde to Devers No. 2
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
U.S.	United States
WECC	Western Electricity Coordinating Council

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Hannes Pfeifenberger is an economist with a background in electrical engineering and over twenty-five years of experience in the areas of electricity markets, regulation, and finance. He has assisted clients in the formulation of business and regulatory strategy, submitted expert testimony to the U.S. Congress, courts, arbitration panels, and regulatory agencies around the world, and provided support in mediation, arbitration, settlement, and stakeholder processes.

Mr. Pfeifenberger specializes in electricity market design, utility industry regulation, transmission, financial valuation, energy industry litigation, and business strategy.

On behalf of his clients, Mr. Pfeifenberger has addressed resource adequacy and capacity market designs, the economic benefits and cost allocation of transmission projects, the reasons behind rate increases, implications of restructuring policies, competitive conduct in electric power markets, and the effects of proposed mergers. He has also explored the benefits of alternative regulation, the desirability of settlement proposals, and the impact of regulatory and legislative actions in the context of evolving market conditions.

He is retained frequently by counsel to testify in regulatory and litigation cases or provide litigation support, including identifying and coordinating expert witnesses and assistance with discovery, depositions, and cross examination on economic or highly technical industry matters.

Before joining The Brattle Group, Mr. Pfeifenberger was a Consultant for Cambridge Energy Research Associates and a Research Assistant at the Institute of Energy Economics at the University of Technology in Vienna, Austria.

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Judy Chang is an economist with a public policy background. She has expertise in the analysis of electricity power markets and advises clients on the financial and regulatory issues relating to renewable energy investment and procurement decisions. She is experienced in leading utility executives, board members, and stakeholders in making challenging strategic decisions complicated by pressures from customers, policy-makers, regulators, and wholesale and retail competitors. Ms. Chang's recent long-term strategic planning engagements have involved the development of future energy market scenarios and assisting utilities to make strategic decisions that balance regulatory requirements for renewable energy, energy efficiency, other demand-side resources, with the potential retirement of existing generation facilities due to various environmental regulations. These projects involved close analyses of relevant regulatory and economic issues surrounding system planning, including considerations for financial, operational, and market design issues.

Ms. Chang has authored numerous expert reports and submitted expert testimony before the U.S. Federal Energy Regulatory Commission and state regulatory authorities regarding power market issues. She has served as an expert witness in regulatory proceedings and litigation settings. Recently, she was an expert witness in evaluating long-term power purchase agreements between renewable energy developers and electric utilities. Her other recent work includes evaluating the potential impact of integrating renewable energy onto power systems. Accordingly, she has designed and helped develop a model that estimates the operational effects and the associated costs of variable resources on a grid.

Ms. Chang has authored a number of articles and reports and presented at a variety of industry conferences. She recently spent two years in India, where she worked on evaluating and financing renewable energy investments for international and multilateral agencies. She holds a Master's in Public Policy from Harvard University's Kennedy School of Government, is a member of the Board of Directors of the Massachusetts Clean Energy Center, and the founding Executive Director of New England Women in Energy and the Environment.