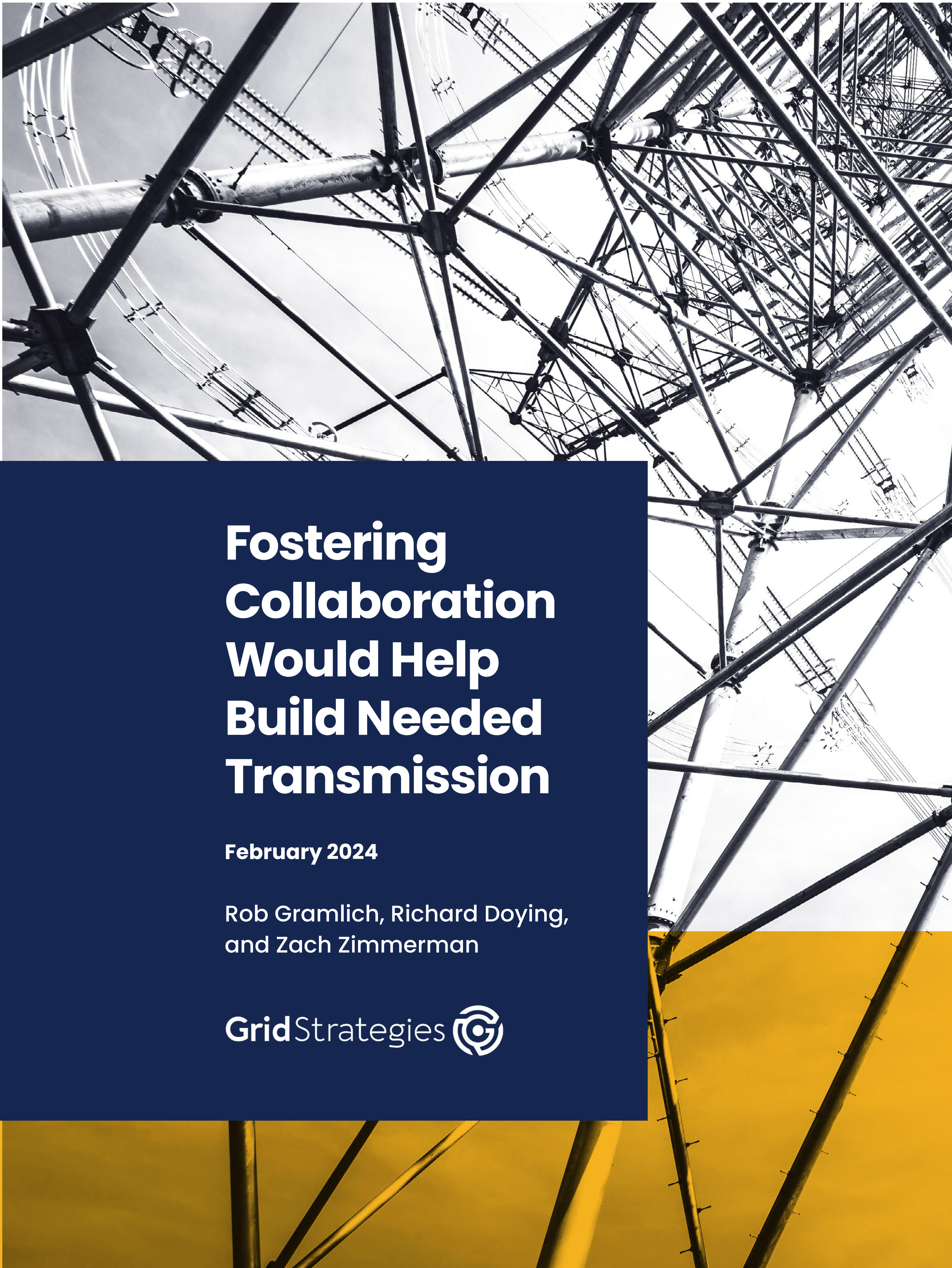

Fostering Collaboration Would Help Build Needed Transmission

February 2024

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Grid Strategies

EXECUTIVE SUMMARY

It is a national priority to expand transmission capacity on the nation's bulk power system to improve grid reliability and resilience and deliver clean, low-cost power to consumers. Building such transmission is notoriously difficult; however, numerous instances of successful transmission expansion prove that it is possible. Given the challenges of developing electric transmission and the need for infrastructure expansion in the coming decades, it is especially critical to learn from hard-earned experience in terms of what drives success. Other reports have noted the importance of well-tailored transmission planning, permitting, and cost allocation policies to drive investment in the high-voltage grid.[1] What else can we glean from the experience of grid expansion to further increase the chances of meeting system needs? In this report, we review dozens of successful major transmission expansion efforts to draw lessons from what has succeeded in getting transmission built.

We find that a common element of successful transmission expansion is collaboration. Collaboration between multiple transmission owners, operators, and planners on various aspects of system analysis, planning, and technology assessment has been prevalent in most examples of successful transmission expansion.

1 *See* Pfeifenberger, J., R. Gramlich, et al., "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs," Brattle Group and Grid Strategies, October 2021 ("Transmission Planning for the 21st Century"), https://gridprogress.files.wordpress.com/2021/10/transmission-planning-for-the-21st-century-proven-practices-that-increase-value-and-reduce-costs-7.pdf. *See also* Grid Strategies/Americans for a Clean Energy Grid, "Transmission Planning and Development Regional Report Card," June 2023 ("Transmission Planning Report Card"), https://www.cleanenergygrid.org/wp-content/uploads/2023/06/ACEG_Transmission_Planning_and_Development_Report_Card.pdf.

The most important aspect of collaboration is the sharing of information, including in the form of expertise held by experienced system planners. Information about system needs, solutions, and potential alternatives is critical to assessing benefits of various solutions and arriving at an actionable path forward. This information is almost always held by multiple entities, none of whom has the whole picture or all the necessary information about interconnected regional grids to arrive at the ideal planning outcome, so this crucial information must be shared. All of the examples reviewed in this paper included elements of information sharing that led to a successful planning outcome. Other common features of successful transmission expansion planning experiences included voluntary interactions by willing participants, equitably shared cost allocation and recovery, and upfront certainty and agreement on project ownership.

The importance of collaboration is not surprising given that there are 330 owners of transmission assets spread across the nation's three integrated networks and that every major transmission asset affects neighboring systems and the regional network. When a facility is added or removed from the grid, it can impact power flows on utility systems hundreds of miles away. The transmission system is a shared network that cannot be expanded without extensive coordination among its various owners, operators, and planners.

The finding is also not surprising given the natural monopoly characteristics of transmission. In contrast to structurally competitive sectors such as generation, the standard elements of textbook natural monopoly persist for electric transmission. It remains more efficient to have one owner of the system in a given area, with economic regulation of that owner, and to avoid duplication of network assets and other utility functions. The basic technological and economic characteristics that led to public utility laws in all states, and at the federal level, are still present. In a regulated natural monopoly sector, unlike in a competitive market, information sharing is allowed and, ideally, encouraged.

The value of collaboration is also not surprising given that collaboration has been a national priority for most of the industry's history. Our review of legislative and regulatory actions going back one hundred years suggests that there have been longstanding and continuous efforts to encourage collaboration among transmission entities. In some cases, we found the delay caused by limiting collaboration can amount to a few billion dollars in a single region.

Policymakers should be interested in fostering collaboration because policy choices significantly impact the amount of information sharing and other forms of collaboration that will occur, ultimately impacting the value of transmission expansion for consumers. The electric supply industry is now partially regulated and partially competitive, due to public policies such as PURPA (1978), the Energy Policy Act (1992), and FERC Order No. 888 (1996) which introduced competition into the generation sector. In general, collaboration tends to be a virtue in regulated monopoly sectors and a vice in competitive sectors (e.g., generation). Collaboration and information sharing is discouraged or even banned by antitrust authorities in competitive sectors.

We find collaboration provides multiple benefits, such as improving the quality and quantity of information used in transmission planning, enabling a more holistic view of system needs, allowing better use of existing assets and rights of way, driving more efficient technology choices, facilitating faster development of needed infrastructure, allowing for improved coordination of outages during and after construction, and facilitating needed stakeholder and policymaker consensus on need and thus, cost allocation and recovery.

This report finds that collaboration in transmission is entirely compatible with and supportive of competition in upstream and downstream sectors that are structurally competitive. In particular, we find that transmission policies which prioritize collaboration and information sharing are in fact pro-competitive by enabling more competition generation sector. By providing real world examples of successful transmission planning outcomes, this report can point policymakers in a direction that bypasses ideological slogans to establish appropriate rules and incentives that foster information sharing and collaboration in support of a timely, efficient transmission buildout.

We conclude that effective collaboration between transmission owners, operators, and planners has been a critical element of getting needed regional and interregional transmission built over multiple decades and across all regions in the electric industry. Unfortunately, however, this report finds that a number of barriers prevent collaboration in transmission planning today. For example, information sharing is sometimes discouraged by incentives (intentional or otherwise) created through regulatory efforts to depart from models that have a proven track record of fostering collaboration. Regulations directing collaboration may not be able to overcome powerful incentives, so regulatory policy should address both incentives and rules. Policymakers should therefore ensure that regulatory rules foster, rather than hinder, information sharing and other forms of beneficial collaboration.

Given the importance of transmission collaboration, policymakers should take care to foster, rather than discourage or prevent, effective collaboration in transmission development.

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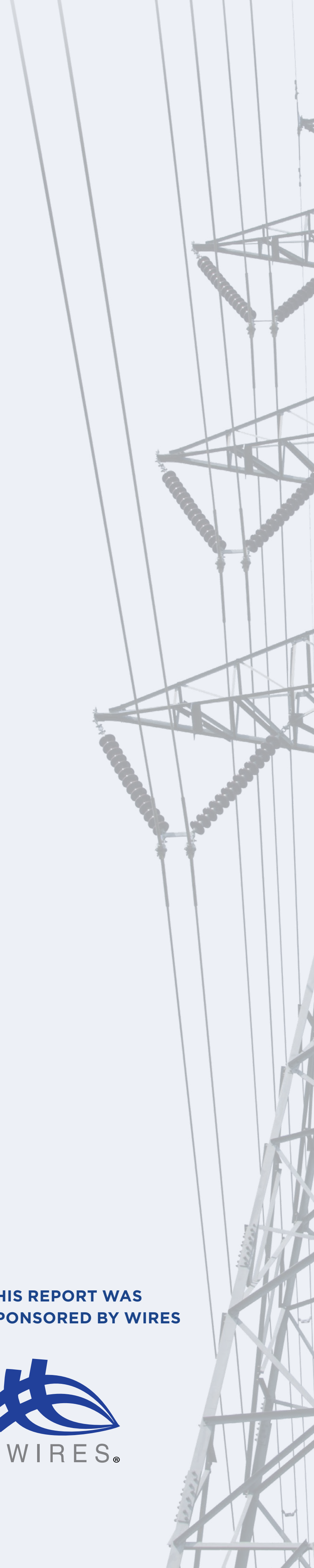

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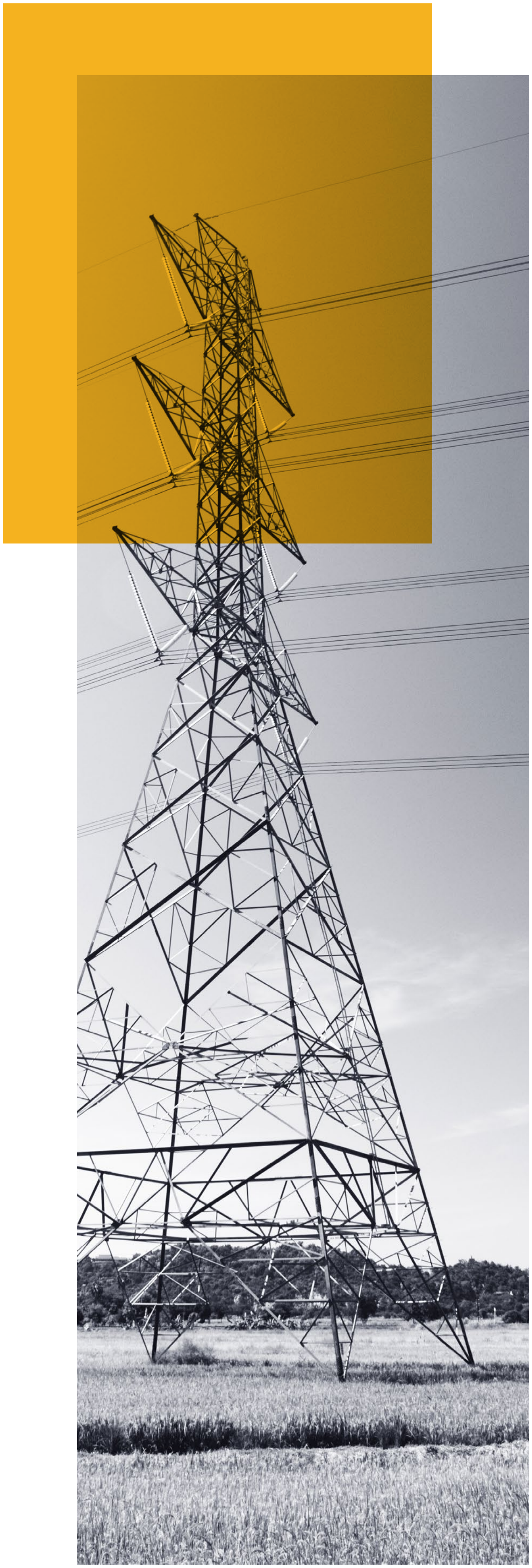

1 INTRODUCTION AND MOTIVATION

A significant expansion of electricity transmission capacity is understood to be critical not only to facilitate clean energy development, but also to facilitate multiple facets of electric system reliability.[2] Transmission is also becoming more widely recognized as necessary to support resource adequacy (the ability of supply to meet demand at times of greatest need)[3] and resilience (the ability to withstand extreme stresses on the grid that are beyond normal planning criteria).[4] The sudden shift into a mode of rapidly growing power demand also suggests a need for new transmission.[5]

Despite these benefits, very little large-scale regional and interregional transmission capacity

2 The US Department of Energy (DOE) National Transmission Needs Study finds that scenarios with high load growth and high clean energy growth in line with the IIJA and IRA requires more than doubling intra-regional transmission capacity by 2035 and quadrupling interregional capacity. The Princeton Net Zero America Report's high electrification scenario finds transmission capacity must double by 2050, and that if transmission expansion is limited to the past-decade rate of one percent, 80 percent of potential emission reductions delivered by the IRA would be lost. A separate study by MIT found a need to almost double transmission capacity to achieve a zero carbon system, and that coordination between states on transmission expansion nearly halves the total US system cost of electricity compared with a state-by-state approach.

3 The accredited capacity value of a portfolio of renewable resources tends to be higher than local resources alone due to the fact that renewables at different locations often produce at different times, so when they are integrated regionally with transmission, they provide a steadier aggregate supply. *See* Derek Stenclik and Michael Goggin, https://gridprogress.files.wordpress.com/2021/11/resource-adequacy-for-a-clean-energy-grid-technical-analysis.pdf.

4 A 2023 Lawrence Berkeley National Laboratory study found that 50 percent of a transmission line's value comes from just 10 percent of the hours annually, usually during times of system stress, such as extreme weather. As an example, during two severe weather events, investment in a transmission line between Texas and TVA would have provided over a billion dollars in benefits during Winter Storm Uri to customers in Texas with the flow of power reversing just two years later during Winter Storm Elliot providing customers in TVA almost $100 million in benefits.

5 *See* J. Wilson and Z. Zimmerman, "The Era of Flat Power Demand is Over," Grid Strategies, December 2023 ("Era of Flat Power Demand is Over"), https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

has been built in the last decade.[6] A report card on regional planning processes found that most regions received a C or lower,[7] indicating widespread barriers to effective planning. Policymakers need to review a variety of means of reversing this trend.

The root causes of recent low levels of large-scale regional transmission development are likely numerous and complex, as are the policy remedies needed to facilitate a period of significantly more rapid infrastructure deployment. Possibilities to increase transmission expansion may be revealed by a review of the many examples of successful transmission expansion that have occurred in recent decades. This paper reviews 29 examples and finds that one common element is collaboration between multiple transmission owners, planners, and/or developers. The role of collaboration is generally under-appreciated in electricity policy, and we therefore explore it in this paper.

Evaluation of the role of collaboration, and how policy incentives either promote or hinder it, is a type of institutional analysis that generally does not appear in the engineering-economic studies that are frequently performed in the electric industry but that can be very important in social science and public policy.[8] Very little research is available to policymakers about institutional incentives and constraints in achieving transmission investment. This paper focuses on institutions and their constraints and incentives related to effective transmission investment and the collaboration that contributes to it.

The paper begins with a definition of collaboration, reviews a history of efforts to increase collaboration in the electric transmission industry, then reviews successful examples of transmission investment that highlight the role of information sharing in facilitating necessary transmission expansion. The paper draws lessons from those examples about the benefits of collaboration and the institutional constraints, disincentives, and other barriers that might prevent or diminish successful collaboration.

6 "The U.S. dropped from installing an average of 1,700 miles of new high-voltage transmission miles per year in the first half of the 2010s, to averaging only 645 miles per year in the second half of the 2010s." *See* J. Caspary, M. Goggin, R. Gramlich, and J Selker, "Fewer New Miles: The US Transmission Grid in the 2010s," Grid Strategies, August 2022, https://gridprogress.files.wordpress.com/2022/08/grid-strategies_fewer-new-miles.pdf.

7 "Transmission Planning Report Card," at 5.

8 "The study of institutions and innovativeness is presently high on the agenda of the social sciences...Every social science discipline - with the exception of psychology - has at least one distinctive strategy for doing institutional analysis." Hollingsworth, J. Rogers. "Doing Institutional Analysis: Implications for the Study of Innovations." Review of International Political Economy 7, no. 4 (2000): 595–644. http://www.jstor.org/stable/4177365. *See also* Baradach and Patashnik, *A Practical Guide for Policy Analysis: The Eightfold Path for More Effective Problem Solving*, "Appendix B Understanding Public and Nonprofit Institutions: Asking the Right Questions" (6th ed., 2020). *See also* https://sesmethods.org/institutional-analysis/.

2 WHAT DO WE MEAN BY COLLABORATION AND WHAT INFLUENCES IT?

Collaboration in this infrastructure development context means companies working together on analysis, project selection, routing, permitting, sharing ownership, cost recovery, and other aspects of building transmission lines. Working together usually includes significant information sharing about system needs, engineering and technical considerations, impacts of various project selection options, and other factors. The relevant parties are mainly those responsible for owning, maintaining, planning, and developing parts of integrated regional grids, but can include other parties as well.

The electric industry has a record of collaboration stemming from a long history of working together as fully regulated utilities with public service obligations, coordinating with neighboring and interconnected service territories. The visible sharing of trucks and crews from distant utilities during storm restoration remains today in mutual assistance programs.[9] Less visible to the general public, but well-known by regulators, have been efforts to coordinate on transmission and generation investments over most of the industry's history. Large electric generation facilities developed in the 1970s and 80s to support rapid load growth were often jointly owned given their large "lumpy" nature and the considerable economies of scale for the types of generation that were being developed at the time .

Later, collaboration waned in the generation sector as it was opened to competition and new entrants in the 1990s. Collaboration is usually discouraged or banned in competitive markets. As a regulated industry, transmission collaboration continued in many instances as catalogued in this report at least through the first decade of the 21st Century.

In Section V, we review 29 historical examples of successful transmission development and then draw lessons from them. Following the section on examples, we evaluate lessons learned and benefits of collaboration, the compatibility and role of different business models, methods of collaboration, barriers to collaboration that exist today, and then provide conclusions for policymakers.

9 Edison Electric Institute, "Reliability, Resilience & Emergency Response," accessed January 4, 2024, https://www.eei.org/en/issues-and-policy/reliability-emergency-response.

3 COLLABORATION AND HORIZONTAL TRANSMISSION INTEGRATION HAS BEEN A LONGSTANDING NATIONAL POLICY

Furthering collaboration among and between transmission providers has been a public policy objective for almost the industry's entire history. The original industry structure of geographically isolated local vertically integrated utilities (generation, transmission, and distribution) was recognized early on as only of limited capability for an interconnected and expanding grid.

COLLABORATION IN THE EARLY 20TH CENTURY TO CREATE INTEGRATED ALTERNATING CURRENT (AC) NETWORKS

In the early 20th Century, geographically larger state regulation of utilities with geographically broader integrated transmission networks replaced local municipal regulation. Westinghouse's AC network capabilities enabled fewer, larger generators to efficiently and reliably serve load if integrated over wider areas through transmission.[10] The change in industry structure was driven by consumers' interest in low rates and greater reliability.[11] G.L. Priest made such a finding and Chris Knittel confirmed through statistical analysis that consumer interests drive the transformation, more so than other possible explanations such as the "capture theory" (self-interest of the utilities) or the 'pure' public interest theory.[12] In this phase, horizontal coordination was achieved through consolidation and creation of geographically larger utility transmission systems.

The 1935 Federal Power Act (FPA) directed the new Federal Power Commission (FPC), a predecessor to the Federal Energy Regulatory Commission created in 1977, to seek regional efficiencies and coordination.[13] FPA Section 202(a) (§824a) states, "[f]or the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation,

10 Priest, G.L., 1993, "The Origins of Utility Regulation and the "Theories of Regulation Debate," Journal of Law and Economics, 36 (2), pp. 289-323.

11 *Id.*; *see also* C. Knittel, "The Adoption of State Electric Regulation," *Journal of Industrial Economics*, 54(2), 201-222, 2006 ("Knittel").

12 "I find evidence consistent with Priest. Greater capacity shortage in a state is correlated with the adoption of state regulation." Knittel at 202; "The results are at odds with both the capture theory and the 'pure' public interest theory." Knittel at 203.

13 Philip L. Cantelon, "The Regulatory Dilemma of the Federal Power Commission, 1920–1977," *Federal History*, 2012, at 68 ("The Regulatory Dilemma"), https://shfg.wildapricot.org/resources/Documents/FH%204%20(2012)%20Cantelon%202.pdf.

transmission, and sale of electric energy,"... "It shall be the duty of the Commission to promote and encourage such inter-connection and coordination within each such district and between such districts." The national security benefits of integration are evident in Section 202(c)(1) which states, "During the continuance of any war in which the United States is engaged, ... the Commission shall have authority, ... to require by order such temporary connections of facilities ..." Section 202(a) encourages horizontal coordination through voluntary actions of utilities and Section 202(c) provides emergency powers to connect. Together these provisions point to the national policy encouraging horizontal coordination of transmission systems.

Regulatory experts in the early days of electric utility regulation were keenly aware of horizontal coordination efficiencies. James C. Bonbright, known for establishing the most widely used rate design principles, suggested "compulsory consolidation into systems found to be economical by the administrative commission" would be a desirable outcome.[14]

COLLABORATION AND INTEGRATION FOR NATIONAL SECURITY IN THE 1930S AND 40S

Later in the 1930s military buildup and production during World War II, these efficiencies and greater capabilities became a priority. There was "urgent prodding" of the industry by the Federal Power Commission towards integration of utilities to enable greater productive capacity by pooling generation across wide areas. "In 1941 and 1942 the Commission invoked its powers of compulsion to order emergency interconnections. Forty-five such orders were issued twenty-six involving interconnections among private utilities, and nineteen interconnections between private utility and public or industrial plants. By this means large blocs of power capacity, which otherwise would have remained idle, were mobilized for war production."[15] The Commission also evaluated physical options to increase horizontal connections between systems in the mid-1930s: "[t]he FPC also investigated the feasibility of a system of high-capacity transmission interconnections tying together the major power-market and industrial centers of the East to assure more economical use of existing capacity and less likelihood for interruption of service in any defense production area."[16]

The debates in the 1930s and 40s were not about the benefits of integration but rather whether the FPC should require it or allow for voluntary utility decisions to integrate. Professor E. W. Clemens stated in 1950: "[w]hether the Commission has positive plans or not, the same effect has been achieved by placing the burden on utility management to work out its own plans for reintegration, subject only to the Commission's veto power. This represents a more rational approach to the problem than one of positive planning, by which systems are integrated by brute force according to the more or less fallible ideas of human administrators."[17]

14 *See* dissenting footnote from James Bonbright in The Twentieth Century Fund, *The Power Industry and Public Interest* 246 (Edward Hunt ed., 1944).

15 Horace M. Gray, "Public Utilities and National Policy: The Integration of the Electric Power Industry," The American Economic Review, Vol. 41, No. 2, Papers and Proceedings of the Sixty-third Annual Meeting of the American Economic Association (May 1951), pp. 538- 549.

16 "The Regulatory Dilemma" at 69.

17 E. W. Clemens, Economics and Public Utilities (Appleton-Century-Crofts, 1950), p. 531. *See also* John Bauer, Transforming Public Utility Regulation (Harper and Brothers, 1950), at p. 305, and SEC statement before the Celler Committee (Study of Monopoly Power, Hearings before the Subcommittee on Study of Monopoly Power of the Committee on the Judiciary, House of Representatives, 81st Cong., 1st sess., 1949, Serial No. 14, Part 2B, pp. 1460-1469).

Whether through voluntary action or FPC prodding, "[b]y the 1960s most power in the United States was pooled, because utilities bought power from one another in accordance with supply and demand."[18] Integration and coordination of transmission systems enabled this pooling of generation.

INCREASED COORDINATION FOR RELIABILITY IN THE 1960S AND 70S

Another stimulant for regional coordination and planning was major blackouts. After the 1965 Northeast blackout, "[t]he utilities responded by establishing a regional coordinating council made up of 22 companies to facilitate better planning within the northeast power system. But when a second blackout occurred in June 1967, many argued that the FPC should have the authority to prescribe the building of adequate interconnections in the public interest. "The story is familiar," The Nation complained, "great potential advantages from technological innovation only partly realized because of a lag in government policy."[19] Thus, the consensus remained and expanded about the value of collaboration and coordination between transmission owners, only the means of achieving it was debated.

COLLABORATION IN THE 1990S AND EARLY 2000S

Moving towards the modern era, following the Energy Policy Act of 1992, which significantly advanced the objective of competitive generation markets, the Commission began a series of initiatives to increase transmission owner collaboration and coordination.

In 1993 FERC issued Regional Transmission Group (RTG) Principles. The Commission stated in the Policy Statement, "[s]ince RTGs bring together both transmitting utilities and their customers (and potential customers) in a region, they can provide a means for companies to coordinate their transmission planning more effectively, avoid costly duplication of facilities, and, in conjunction with their respective state commissions, find more efficient solutions to region-wide problems. This is critical because the transmission network is highly interconnected; thus, the actions of one party often affect many others."[20]

In 1996 FERC in Order No. 888 suggested Independent System Operator (ISO) Principles to encourage coordination. The Commission stated, "we see many benefits in ISOs, and encourage utilities to consider ISOs as a tool to meet the demands of the competitive marketplace."[21]

In 1999 the Commission issued Order No. 2000 which encouraged voluntary creation of Regional Transmission Organizations (RTOs). The Order stated, "[c]oordination of activities among regions is a significant element in maintaining a reliable bulk transmission system and for the development of competitive markets...We will require an RTO to develop mechanisms

18 "The Regulatory Dilemma" at 76

19 *Id.*

20 FERC, "Policy Statement Regarding Regional Transmission Groups," 58 Fed. Reg. 41626 (August 5, 1993), https://archives.federalregister.gov/issue_slice/1993/8/5/41621-41634.pdf#page=6, pp. 6-7.

21 Order No. 888-A, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 62 Fed. Reg. 12274 (Mar. 14, 1997), FERC Stats. & Regs. at 31,655, https://www.ferc.gov/sites/default/files/2020-05/rm95-8-00w.txt.

to coordinate its activities with other regions whether or not an RTO yet exists in these other regions."[22]

In 2003, the Commission indicated its intent to require integration through mandatory participation in Regional Transmission Organizations through its Standard Market Design (SMD) proceeding.[23] The Commission ultimately did not adopt Standard Market Design or its mandatory RTO participation requirement. This decision follows the many decades described above of favoring integration and coordination of transmission but a lack of national consensus on whether that should be mandated. The Commission stated, "[t]ransmission planning and expansion have generally been performed for a single control area rather than on a regional basis. This yields sub-optimal solutions, as individual transmission providers consider power flows across a limited area and do not adequately consider entire markets. Parallel path flows that occur on neighboring systems may make the construction of specific facilities less cost-effective than a regional solution. This effect can be properly considered by performing transmission planning and expansion on a regional basis. Moreover, facilities that, if constructed in one system would be the optimal solution for a neighboring system, might never be considered under a single control area-based planning model. Implementation of Standard Market Design will only increase the importance of examining these issues on a regional basis. More open and transparent markets will enable customers to purchase from distant suppliers, increasing use of the grid."[24]

In 2007 the Commission issued Order No. 890. The first of the eight principles in Order 890 was "coordination," and principle number four was "information exchange." (The eight were: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, and congestion studies).[25] The Commission stated, "[t]o ensure that truly comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, we amend the pro forma OATT to require coordinated, open, and transparent transmission planning on both a sub-regional and regional level."[26] Data exchange was a major focus of Order No. 890. The order "directs public utilities, working through NERC, to revise the related MOD reliability standards to require the exchange of data and coordination among transmission providers…"[27]

FERC Order No. 1000 issues in 2011, the last in the series of major orders on regional coordination required, among other things, "[p]lanning and coordinating transmission expansion."[28] Other aspects of Order No. 1000 arguably hindered collaboration, possibly inadvertently, as we discuss below.

This long series of initiatives spanning most of the industry's history shows the consistency of regional coordination and collaboration as a national priority.

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22 Order No. 2000, Regional Transmission Organizations, 65 Fed. Reg. 809, P 494 (2000).

23 Standard Market Design, RM01-12, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20020731-2000&optimized=false.

24 SMD NOPR PP 336-337 (https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20020731-2000&optimized=false).

25 *See* Order No. 890, Preventing Undue Discrimination and Preference in Transmission Service, 72 Fed. Reg. 12265 (2007).

26 *Id.* at P 84.

27 *Id.* at P 310.

28 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (July 21, 2011) ("Order No. 1000").

4 TRANSMISSION COLLABORATION SUPPORTS GENERATION COMPETITION

Should transmission be competitive? Should policymakers support "competition" across the board in all sectors? These questions are often debated in electric industry regulatory proceedings. It is important to note that through the 1980s, 1990s, and early 2000s, generation competition was a national policy, and transmission was meant to serve as a platform for generation competition, not be competitive itself.

Generation competition has been an explicit national priority since 1992. As illustrated by the statements in Order Nos. 888, 2000, and 890 and the SMD proposal above, the main motivation for the Commission's support for collaboration and coordination in the transmission space was to enable competitive generation markets. Leading industrial organization and regulatory economists such as Alfred Kahn and his student Paul Joskow identified the generation sector as the part of the electric industry that was structurally competitive. Congress responded with the 1992 Energy Policy Act (EPAct 1992) creating a new class of competitive generators called "Exempt Wholesale Generators" (EWGs).[29] EWGs could sell power with few restrictions (exempt from the Public Utility Holding Companies Act), and required transmission providers to provide third parties the ability to deliver power over their systems.[30] Thus, the legislation established generation competition as a goal, and transmission access as an enabler of generation competition.

FERC's first major action after EPAct 1992 was to increase regional collaboration through its Regional Transmission Group Policy Statement which encouraged collaboration as described above.

Three years later FERC more forcefully implemented EPAct by requiring open access to transmission systems for more geographically expansive power markets. FERC Order No. 888 in 1996, arguably the most significant rule in the agency's history, was "designed to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers."[31] The Order explained the distinction between the competitive generation sector and the regulated transmission sector: "[t]he electric industry faced the situation "where the price of each incremental unit of electric power exceeded the average cost. Bigger was no longer better."[32] This structural competitiveness based on evolving generation technology distinguished generation from transmission and provided the economic foundation for generation competition and explains

29 Energy Policy Act of 1992, Public Law 102-486, Title VII, Subtitle A, https://afdc.energy.gov/files/pdfs/2527.pdf.

30 *Id.*

31 Order No. 888-A at 1.

32 *Id.* at 18.

why generation was deregulated and transmission was treated as a regulated monopoly sector and platform for competition.

Order No. 888 treated transmission as a regulated platform to support generation competition. The Commission's assessment of transmission was not about it being competitive itself but about enabling large regional generation competition through coordination of systems. "The nature and magnitude of coordination transactions have changed dramatically since enactment of the FPA, allowing increased coordinated operations and reduced reserve margins. Substantial amounts of electricity now move between regions, as well as between utilities in the same region. Physically isolated systems have become a thing of the past."[33] The Order required open access of transmission using the new EPAct provisions: "these sections now give the Commission broader authority to order transmitting utilities to provide wholesale transmission services, upon application, to any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale."[34]

The Commission followed Order No. 888 with Order No. 2000 in 1999 to encourage Regional Transmission Organizations to increase operational and transmission planning coordination and collaboration. The Order stated, "[c]oordination of activities among regions is a significant element in maintaining a reliable bulk transmission system and for the development of competitive markets…We will require an RTO to develop mechanisms to coordinate its activities with other regions whether or not an RTO yet exists in these other regions."[35] The Order quoted the Commission's staff report saying "[t]he necessity for cooperation in meeting reliability concerns and the Commission's intent to foster competitive market conditions underscores the importance of better regional coordination in areas such as maintenance of transmission and generation systems and transmission planning and operation."[36]

During the early period of restructuring, the economics profession continued to suggest opportunities for greater generation competition through transmission collaboration and coordination. By expanding the geographic breadth of the bulk power system, there would be more generators competing with each other, with lower market concentration, and therefore more likelihood of low, competitive power prices. In 2005 Stanford economist Frank Wolak stated, "[e]xpansion of the transmission network typically increases the number of independent wholesale electricity suppliers that are able to compete to supply electricity at locations in the transmission network served by the upgrade…With the exception of the U.S., most countries re-structured at a time when they had significant excess transmission capacity, so the issue of how to expand the transmission network to serve the best interests of wholesale market participants has not yet become significant. In the U.S., determining how to expand the transmission network to serve the needs of wholesale market participants has been a major stumbling block to realizing the expected benefits of electricity industry re-structuring."[37] Most electricity economists supported widening the geographic markets through the creation of large integrated independent system operators or Regional Transmission Organizations where

33 Order No. 888-A at 21.
34 *Id.* at 30-31.
35 Order No. 2000 at P 494.
36 *Id. at* PP 19-20.
37 F. A. Wolak, "Managing Unilateral Market Power in Electricity," Policy Research Working Paper; No. 3691. World Bank, Washington, DC, 2005, p. 9.

the many Balancing Authorities and planning entities were consolidated into one transmission organization that operated and planned the system.

This focus on collaboration and coordination to support competition may be counterintuitive to some. Within competitive sectors, coordination can harm competition and of course many forms of coordination and collaboration are banned by antitrust policies (collusion, price fixing, etc.). But through at least 20 years of federal electricity policy, there was a clear consensus and direction to *increase* collaboration and coordination in transmission to support greater competition in the *generation* sector. The FERC initiative described above show the congruence of transmission collaboration with generation competition.

5 EXAMPLES OF EFFECTIVE TRANSMISSION PLANNING AND INTEGRATION

In this section, we describe a number of examples of successful regional and interregional transmission investment, with a particular focus on the role of collaboration in contributing to that success. The examples demonstrate that while the motivations, forms, and breadth of collaboration have varied widely, collaboration has been a key element of successful transmission expansion. Moreover, collaboration as part of successful transmission development has occurred over many decades and across all regions and types of transmission organizations. Most of the examples pertain to large regional and interregional lines, of the sort particularly needed now for ensuring reliability integrating clean energy, and to serve load growth. We observe that collaboration has been especially important in these instances of large scale regional and interregional lines since transmission spanning multiple utility service territories affects many entities. We describe the investments, the roles of relevant parties, and how the collaboration worked.

THE WEST

California network upgrades and Tehachapi area[38]

The Tehachapi area transmission projects and California network upgrades are a good example of collaboration between multiple utilities and an ISO. The projects amounted to a $1.8 billion investment in three new 500 kV transmission lines to allow the interconnection of 4,350 MW of new wind generation from the Tehachapi area in California's central valley. The lines were approved in 2007. Planning for the project began in 2004 with the Tehachapi Collaborative Study Group. The group identified a number of alternative plans and recommended further study of the alternatives by CAISO.

This recommendation led to the further study of transmission solutions by the CAISO South Regional Transmission Planning (CSRTP-2006) Team, a technical project team composed of representatives from CAISO participating transmission owners or PTOs (PG&E, SCE, and SDG&E), other project sponsors (Nevada Hydro Company, Citizens Energy, Imperial Irrigation District, Oak Creek Energy System/Tehachapi Holdings), and representatives from the California Energy Commission (CEC) and the California Electricity Oversight Board (EOB). This

38 *See* Armie Perez, *Memorandum to California Independent System Operator Board of Directors re Decision on Tehachapi Projects*, January 2007, https://www.caiso.com/Documents/DecisiononTehachapiProject-Memo.pdf.

CSRTP-2006 was not a stakeholder forum but rather a technical group providing CAISO with the necessary technical data as well as the "real-time" technical advice it needed to conduct its analysis.

CAISO studied the Tehachapi Transmission Project as part of its CAISO South Regional Transmission Plan for 2006 (CSRTP-2006) in full collaboration with SCE and other CSRTP-2006 participants and developed a least-cost solution for the network component of the transmission infrastructure that interconnected planned generation projects in the Tehachapi area to CAISO. The analysis conducted as part of this collaborative planning effort demonstrated the upgrades were justified on their interconnection value alone but also identified multiple additional benefits, including reliability, efficiency and policy benefits. These benefits were determined because of the collaboration of parties involved, including technical data and expertise the transmission owners and other project sponsors were able to provide.

Boardman to Hemingway

The Boardman to Hemingway project arose out of bilateral utility discussions in the Pacific Northwest. The line is a $1.2 billion, 290-mile 500 kV AC transmission line from Idaho to Oregon. Conversations around the regional need and project initially began in 2007, with the project initially being developed by PacifiCorp, Idaho Power, and Bonneville Power Authority (BPA). However, BPA sold its share to the other two utilities in 2022. The need for the line was driven by increased load from population and business growth in the Pacific Northwest and Intermountain West. The project will help utilities meet customer demand, especially during the Pacific Northwest's winter peak and the Mountain West's summer peak, and improve reliability, reducing the likelihood and duration of outages, while helping to keep energy prices affordable. The project was initially planned as a 230 kV line but was upscaled to 500 kV as the magnitude of benefits became apparent. Boardman to Hemingway required approval and cost recovery from state PUCs as well as asset transfers between the two utilities to better align usage with need. For the exchange, Idaho Power transferred power generation units to PacifiCorp, and PacifiCorp transferred Idaho Power several transmission lines in exchange. The Boardman to Hemingway transmission line ownership agreement gives PacifiCorp 55% ownership and Idaho Power 45% ownership of the line. According to the terms of an agreement finalized March 24, 2023, Idaho Power will recover part of its costs by delivering energy to Bonneville Power Administration customers in eastern Idaho.[39] These agreements, reached through extensive utility collaboration, were critical to move the project forward.

Colstrip

The Colstrip Transmission project expanded on utility collaboration related to hydropower in the West. The Colstrip project is comprised of two 250-mile 500 kV lines that deliver power from the Colstrip coal power plants in eastern Montana to the Pacific Northwest. In the late 1960s, the first two Colstrip units were initially planned with just over 600 MW of capacity by Montana Power Company (MPC) and Puget Sound Energy (PSE). The units came online in the

39 Idaho Power Staff, interview with the authors, October 20, 2023. *See also* Idaho Power, "Boardman to Hemingway: Purpose and Need," accessed January 5, 2024, https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/boardman-to-hemingway/purpose-and-need/.

mid 1970s. These units were initially connected to the grid by 230 kV lines which were built to be upgradeable to 500 kV specifications.[40] The need for the generation and new transmission lines arose from BPA forecasts showing that all baseload power would be consumed by load growth.[41] When BPA reiterated this forecast in the early 1970s five utilities, MPC, PSE, Portland General Electric, Avista, and PacifiCorp, announced the development of two more Colstrip units, adding almost 1500 MW of new capacity. The development, completed in the 1980s, included upgrading the existing transmission to 500 kV and connecting the generation to Bonneville Power Administration's (BPA) system to allow delivery of power to the Pacific Northwest. This new construction meant that the powerplants and transmission lines were jointly owned by Northwestern, PSE, PGE, Avista, and PacifiCorp. The complex ownership agreement of the Colstrip transmission lines was a product of extensive collaboration and was needed to alleviate permitting and rate-making concerns of some utilities.[42] It is unclear how such a project could have been built without the participation of utilities who were the only entities able to apply to state commissions for cost recovery.

Western Spirit

Western Spirit was a public/private partnership with a state authority. It is a 155-mile 345 kV transmission line. The project was initially developed jointly by the New Mexico Renewable Energy Transmission Authority (NM RETA) and Goldman Sachs Infrastructure Partners (GSIP). In 2013, GSIP sold their share in the project to Clean Line Energy Partners who carried on the development through 2018, when they sold the project to Pattern Energy. NM RETA and its various private partners spent many years on feasibility evaluation, planning, permitting, design, land acquisition, financing, government agency coordination; and ultimately procurement, construction, testing, and operation.[43] The line was in part supported by California demand. The Los Angeles Department of Water and Power, San Jose Clean Energy, East Bay Community Energy, California Choice Energy Authority and member cities, and international energy company Uniper Global Commodities, which provides power to local New Mexicans all signed PPAs for the line. Western Spirit Wind includes four wind energy project sites in Central New Mexico: Red Cloud, Duran Mesa, Clines Corners, and Tecolote. Totaling 1,050 MW of installed capacity, Western Spirit Wind represents the largest single wind power development in America.[44] After the line became operational The Public Service Company of New Mexico (PNM) acquired the line, which was the largest upgrade in PNM territory, strengthening their existing system and enabling the transfer of 800 MW of new wind power. The interconnection required upgrading two substations and an existing PNM transmission line.[45] The example highlights a collaboration with a state agency as well as the local utility, off-takers, and the independent developers.

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40 U.S. Department of Energy, *Record of Decision for the Bonneville Power Administration Garrison-Spokane 500-kV Transmission Project*, May 1983, https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/1983-rod/rod-19830523-garrison-spokane-550-kv-transmission-project.pdf.

41 Puget Sound Energy, "Integrated Resource Plan: Appendix K Colstrip," 2017, K-6, https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/IRP17_AppK_083017.pdf.

42 Keogh, Ross Patrick, "Market Power and Regulatory Failure in the Montana Wholesale Electricity Market" 3-8 (2012). Graduate Student Theses, Dissertations, & Professional Papers. 646, https://scholarworks.umt.edu/cgi/viewcontent.cgi?article=1665&context=etd.

43 Pattern Energy Group LP, "Pattern Energy and RETA Announce Energization of Western Spirit Transmission Line in New Mexico," December 2021, https://www.prnewswire.com/news-releases/pattern-energy-and-reta-announce-energization-of-western-spirit-transmission-line-in-new-mexico-301437725.html.

44 *Id.*

45 NS Energy Business, "Western Spirit Transmission Line Project," accessed January 5, 2024, https://www.nsenergybusiness.com/projects/western-spirit-transmission-line-project/.

The Transmission Agency of Northern California

Established in 1984, the Transmission Agency of Northern California (TANC) is a joint powers agency. The agency's mission is to provide electric transmission for public power members, including various California cities and utility districts. Its members include the California cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara and Ukiah, as well as the Sacramento Municipal Utility District, the Modesto Irrigation District, and the Turlock Irrigation District. The first line TANC planned, developed, and operates is the California-Oregon Transmission Project (COTP), a 340-mile, 500-kV transmission line, discussed further in this report below. TANC owns 87 percent of COTP and coordinates use of the line among project participants including entities such as Western Area Power Administration and Pacific Gas & Electric Company.[46] TANC has worked on other transmission plans, such as the TANC Transmission Program (TTP), which was a $1.2 billion initiative for constructing 500-kV and 230-kV facilities in northern California. The plan was aimed at enhancing reliability and facilitating access to renewable resources and TANC encouraged collaboration with Western Electricity Coordinating Council and WestConnect members, with over twenty entities participating in technical review of the planning work.[47]

PacifiCorp

PacifiCorp, like many major utilities, emerged through horizontal mergers in the 20th century. Thus, it was a corporate structural change that enabled collaboration across what had been independent utilities Pacific Power and Light (serving Oregon, California, and Washington), Rocky Mountain Power (serving Utah, Wyoming, and Idaho), and Utah Power and Light, which itself originated from the merger of four different utilities in 1912 catering to customers in Utah, Idaho, and Wyoming. Presently, the utility serves nearly two million customers across six states.[48] PacifiCorp follows a biennial transmission plan, as outlined in Attachment K of the Open Access Transmission Tariff (OATT), aligning with FERC Order No. 1000 and planning over a 10-year horizon. Additionally, transmission planning and solutions are integrated into its 20-year Integrated Resource Planning (IRP) process. This strategic planning approach has spurred the initiation of the Gateway Energy Projects, involving an $8 billion investment in over 2,300 miles of new transmission lines across the six-state footprint.[49] The projects will increase connections and energy transfer between the two balancing authorities that PacifiCorp operates. In its 2021 IRP, PacifiCorp noted that the projects will increase system reliability by connecting load centers to resource rich areas as well as helping PacifiCorp meet its state RPS requirements. The projects were initially introduced in 2007 and have undergone evaluation from a number of parties during an 18-month stakeholder process in accordance with WECC Regional Planning Project Review guidelines and FERC OATT planning principles.

46 American Public Power Association, "Joint Ownership of Transmission," 8 (2009) ("APPA"), https://www.energy.gov/sites/prod/files/2015/03/f20/Paper%20Joint%20Transmission%202009%20update.pdf.

47 *See* Transmission Agency of Northern California, *Comments of the Transmission Agency of Northern California In Response to the Western Area Power Administration's Request for Public Comments on a Proposed Transmission Infrastructure Program*, Federal Register, Vol. 74, No. 41, page 9391, April 2009, https://www.energy.gov/articles/interestedpartiestancwapa040309pdf.

48 PacifiCorp, "About," accessed January 5, 2024, https://www.pacificorp.com/about.html.

49 PacifiCorp, "Energy Gateway," accessed January 27, 2024, https://www.pacificorp.com/transmission/transmission-projects/energy-gateway.html#:~:text=PacifiCorp's%20Energy%20Gateway%20Transmission%20Expansion,%2C%20Utah%2C%20Idaho%20and%20Oregon.

The process established need, assessed benefits to the region, vetted alternatives, and eliminated duplication of projects. PacifiCorp is recovering costs through state PUC's where it operates.[50]

Southwest Model

Across the West and Southwest, joint planning and ownership of generation and transmission projects has historically been the norm more than the exception. Many major generation projects have been built far from load centers and the joint ownership model of transmission has been a key to success for West and Southwest utilities to plan and develop transmission to serve rapidly growing customer loads. This model has resulted in a more integrated transmission system across the West and Southwest. The model has been used so many times that the American Public Power Association (APPA) has named the joint ownership model "The Southwest Model."[51] The model generally relies on common principles including collaborative planning and ownership and transfer capacity is usually a percentage based on capital investment by each utility to the project.[52] An example of projects developed under this model is described below.

Navajo West and South Transmission Systems

The Navajo West 500-kV transmission lines and Navajo South transmission lines, developed in conjunction with the Palo Verde nuclear plant and Navajo generating stations in Arizona, provides an example of the Southwest Model. The transmission lines from Palo Verde to Phoenix are jointly owned by Arizona Public Service Company (APS), Salt River Project (SRP), PNM, and El Paso Electric Company. The Palo Verde nuclear plant and switchyard share ownership among these four utilities and additional entities: Los Angeles Department of Water & Power, Southern California Public Power Authority, and Southern California Edison Company. The Navajo South transmission lines, extending from the Navajo generating stations to the Moenkopi switching station, are owned by six entities: SRP, APS, LADWP, the U.S. Bureau of Reclamation (USBR), Tucson Electric Power Company, and Nevada Power Company. Among these, Nevada Power, USBR, and LADWP collaborated on constructing the Navajo West transmission system, which extends west from the plant.[53] As a part of the collaboration, the utilities formed a coordinating committee that oversaw the planning and construction, as well as entered agreements for Los Angeles and Nevada to operate the transmission system.[54]

Pacific DC and AC interties (WECC Paths 65 & 66)

Another example of collaborative transmission planning and joint ownership are the AC and DC interties connecting California and the Pacific Northwest on the West Coast. The concept traces

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50 PacifiCorp, *Integrated Resource Plan Volume I,* September 2021, at 83-104, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf.

51 APPA at 7.

52 *Id.*

53 *Id.*

54 "Navajo Project Coordinating Committee Agreement No. 125," at 1, February 2017, https://library.cap-az.com/documents/meetings/2017-02-16/1611-Agreement-No125.pdf; "Navajo Project Co-Tenancy Agreement," 1976, at 7, https://www.sec.gov/Archives/edgar/data/7286/000095015306000633/p71939exv10w107.txt.

back to 1919, and was included as a reason to create the BPA by President Franklin Roosevelt.[55] The Pacific Intertie transmission lines link the systems of utilities in eleven states plus British Columbia, including the largest hydropower system (BPA), the largest municipal system (Los Angeles), and the largest privately-operated system (Pacific Gas and Electric) in the United States.[56] There are four transmission lines in total, three AC lines and a DC line. Collectively, the three HVAC lines are known as Path 66. Planning for the initial two Path 66 lines began under President Kennedy in the 1960s led by BPA, which culminated with Congress providing over $40 million to begin construction of the lines.[57] In 1984, the Transmission Agency of Northern California (TANC) was established as a joint-powers agency by a group of publicly owned utilities. TANC's first project was the construction of the 340-mile, 500-kV AC transmission line between southern Oregon and central California, which is the newest HVAC transmission line in Path 66. The project provides reliability benefits to the grid, increases transfer capabilities between California and the Pacific Northwest, while also providing economic benefits between $50-$100 million annually for Northern California ratepayers. TANC owns 87 percent of the transmission line and is the project manager, coordinating the use of the facilities among project participants. Other owners of the transmission line include Western Area Power Administration, which is also contracted to provide operations and maintenance, Pacific Gas & Electric Company, the City of Redding, and the Carmichael Water District.[58] The DC portion of the Pacific Intertie, also known as Path 65, is an almost 850-mile HVDC transmission line delivering hydropower from the Columbia River in Oregon to Los Angeles, California. The project is also jointly owned, with ownership switching at the Nevada border from BPA and Portland General Electric, where BPA controls most of the capacity, to LADWP and SCE who own equal shares of the line.[59] The project, developed through this multi-utility, multi-state collaborative process provides a wide range of benefits, including transfer of provided additional power to Southern California during shortages, provided peaking power to the Pacific Northwest, and mitigating rising fuel costs.[60]

Path 15 Upgrades

Almost every WECC transmission path, including Path 15, serves as an example of jointly planned and owned projects. Path 15, located in PG&E's service territory, was originally built in the 1970s and 1980s, with upgrades to the path planned in the 1990's to facilitate the transfer of excess hydropower from the Pacific Northwest to California and the Southwest without constructing new power plants. This transmission line faced capacity limitations, which potentially contributed to the California electricity crisis in 2000–2001. To address this issue, WAPA, PG&E and Trans-Elect New Transmission Development undertook a collaborative public-private partnership effort to enhance Path 15's capacity. The financing was a mix of non-Federal funds in a public-private partnership. The project involved constructing a third

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55 Northwest Power and Conservation Council, "Intertie," accessed January 5, 2024, https://www.nwcouncil.org/reports/columbia-river-history/intertie/.

56 Oregon Historical Society, "Oregon History Project: Pacific Intertie Map," accessed January 5, 2024, https://www.oregonhistoryproject.org/articles/historical-records/pacific-intertie-map/#:~:text=The%20idea%20for%20a%20high,direction%20of%20President%20John%20F.

57 *Id.*

58 Transmission Agency of Northern California, "The California-Oregon Transmission Project," accessed January 5, 2024, https://www.tanc.us/projects/cotp/.

59 *See* Northwest Power and Conservation Council, *Pacific Intertie: The California Connection on the Electron Superhighway*, May 2001, https://www.nwcouncil.org/sites/default/files/2001_11.pdf.

60 *Id. at 5.*

500 kV line eliminating a significant transmission constraint and raising the maximum south-to-north transmission capacity to 5,400 MW. The upgrade plan included constructing the new transmission line, modifying existing substations, and establishing a second circuit on a line. The project was needed to increase reliability, alleviate constraints, and provide economic benefits by fostering a more robust electricity market in California. Construction commenced in fall 2003, and upon completion in late 2004, operational control was handed over to CAISO.[61]

SPP

Balanced Portfolio Projects

In 2005, SPP determined that it would need significant transmission upgrades, and SPP's Cost Allocation Working Group (CAWG) began a process outlining a "Balanced Portfolio" cost allocation approach.[62] In 2007, SPP began a strategic initiative to develop a group of economic transmission upgrades that benefited all of SPP by reducing congestion. The final plan, approved in 2009, included $692 million for 631 miles across five new 345 kV lines along with system upgrades.[63] There were seven different owners of the portfolio of projects. The benefits from these five lines were estimated to be $1.8 billion over ten years.[64] Costs for the projects were broadly allocated across SPP's footprint. SPP's Cost Allocation Working Group, which reports to SPP's Regional State Committee, spent significant time through its stakeholder process to identify upgrades that would provide a balanced benefit to SPP members over a specified 10-year payback period. Pursuant to Attachment O of SPP's Regional Tariff, a portfolio of projects is "balanced" when for each zone within SPP, the sum of the benefits of the potential Balanced Portfolio are equal to or exceed the sum of the costs.[65] SPP's tariff allows for the adjustment of revenue requirements to achieve balance for the portfolio. To begin the process, projects for evaluation were initially identified and submitted by both stakeholders and staff, with SPP evaluating over 50 projects to develop the final portfolio.[66] Throughout the planning there was extensive RTO and stakeholder collaboration with SPP staff and stakeholder committees working with transmission owners and load serving entities to update and vet economic models to ensure that all member data was represented accurately. Stakeholders provided load and resource forecasts for their footprints, load profiles, fuel prices and outage and maintenance rates to SPP staff.[67] The entire process, from identifying needs, conducting studies, developing a project portfolio and determining cost allocation was facilitated by collaboration between transmission owners, the RTO, and other stakeholders.

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61 *See* Western Area Power Administrator, "Path 15 Upgrade Project," 2004, https://web.archive.org/web/20130324142126/http://www.wapa.gov/sn/ops/transmission/path15/factSheet.pdf

62 Southwest Power Pool, *SPP Priority Projects Phase II Report*, February 2010, at 19 ("*Priority Projects Phase II"*), https://www.spp.org/documents/11467/priority%20projects%20phase%20ii%20report.pdf.

63 Southwest Power Pool, "Balanced Portfolio," accessed January 5, 2024, https://www.spp.org/engineering/transmission-planning/balanced-portfolio/.

64 Southwest Power Pool, *SPP Balanced Portfolio Report,* June 2009, at 38 ("*Balanced Portfolio Report*") https://www.spp.org/documents/10115/rscaddbkg072709.pdf.

65 Southwest Power Pool Open Access Transmission Tarff, Sixth Revised Volume No. 1 Attachment O, Section IV.4., https://spp.etariff.biz:8443/viewer/viewer.aspx.

66 National Renewable Energy Laboratory, "Moving Beyond Paralysis: How States and Regions Are Creating Innovative Transmission Projects," Exeter Associates, Inc., May 2009-May 2010, at 13 ("Moving Beyond Paralysis"), https://www.researchgate.net/figure/SPPs-Balanced-Portfolio-Projects_fig4_241962238.

67 *Balanced Portfolio Report at* 46.

SPP Priority Projects

Building off the collaboration in the Balance Portfolio Projects, in 2010 SPP planned and approved a group of six "priority" high voltage (345 kV) electric transmission projects and upgrades estimated to bring benefits of at least $3.7 billion to the SPP region over 40 years and connect just over 3 GW of new wind generation.[68] The projects were intended to reduce congestion, better integrate SPP's east and west regions, improve SPP members' ability to deliver power to customers, and facilitate the addition of new renewable and non-renewable generation to the electric grid.[69] The idea for Priority Projects was developed by the Synergistic Planning Project Team (SPPT). The SPPT grew out of the experience developing the Balanced Portfolio projects with the goal of better integrating all SPP's transmission planning processes.[70] The SPPT group consisted of state regulators and SPP member representatives. For the Priority Projects, SPP, transmission owners, and states shared studies and data in the process and all groups provided initial projects ideas, in the same manner as with the Balance Portfolio process. Wherever possible public data was used in an attempt to treat stakeholders similarly and limit disclosure of proprietary information, but SPP members nonetheless reviewed a significant number of inputs including: maximum capacity, unit type, commission date, retirement date, bus, minimum capacity, maintenance required hours, forced outage rate, forced outage duration, minimum downtime, minimum run time, must run status, ramp rates, and demand data. Members also reviewed the data to ensure that all units were being accounted for and were being modeled in the correct zone and reviewed the PROMOD results to see if unit dispatch was realistic.[71] Then benefits assessments were provided by SPP to states and stakeholders for review and approval. In addition, a cost allocation framework called "highway-byway" cost allocation was developed by the CAWG as a part of this collaborative process.[72] Ownership was agreed to among utility transmission owners in the region, generally following the geographic footprint such that the local transmission owners owned the lines if they so elected. (This process occurred before FERC Order No. 1000 which eliminated the federal Right of First Refusal). A balance of benefits and costs to each utility service area was sought through the process of evaluating both benefits and costs by load zone. The lines were built, and significant transmission capacity brought on-line, enabling an ongoing wind resource expansion that has resulted in renewables accounting for up to 90 percent of production in some hours. "In a decade's time, our region has gone from thinking of 25% renewable-penetration levels as nearly unreachable to a point where we regularly exceed 75% without reliability concerns," SPP Senior Vice President of Operations Bruce Rew said. "SPP's geographic diversity and robust transmission system make the successful deployment of wind and other renewables possible."[73]

68 Southwest Power Pool, "Priority Projects," accessed January 5, 2024 ("Priority Projects"), https://www.spp.org/engineering/transmission-planning/priority-projects/; *Priority Projects Phase II* at 9.

69 "Priority Projects."

70 "Moving Beyond Paralysis" at 14.

71 *Priority Projects Phase II* at 13.

72 National Renewable Energy Laboratory, "A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations," Exeter Associates, Inc, 2011, at 22-23, https://www.nrel.gov/docs/fy11osti/49880.pdf.

73 Southwest Power Pool, "SPP sets regional records for renewable energy production," March 2022, https://www.spp.org/news-list/spp-sets-regional-records-for-renewable-energy-production/.

MISO

CAPX2020 (Capacity Expansion by 2020) Projects

The CAPX2020 projects were five new high-voltage transmission lines totaling over 800 miles and $2 billion in investment across Minnesota, North Dakota, South Dakota, and Wisconsin in the upper Midwest. In total, the transmission lines enabled the interconnection of approximately 8,000 MW of new generation. At the time, the CapX2020 projects were the largest proposed development of new transmission in the area in over 40 years. The CAPX2020 projects were developed by eleven utilities including cooperatives, municipals, and investor-owned utilities. There was a mutual recognition of the need for transmission investment. The utilities formed the CAPX group in 2004 as a "joint initiative to upgrade and expand the transmission grid in the Upper Midwest, meet the growing demand for electricity, support job and population growth, and increase access to renewable energy sources."[74] Beyond the recognition of need, the utilities also understood that it was more efficient to jointly plan and develop the projects. The utilities worked collaboratively to develop construction standards that were uniform across the states and projects.[75] They also sought cost recovery from each of the states involved. Ownership on individual lines was divided among utilities and in some cases the existing transmission lines were attached to the CAPX2020 project towers.[76] According to participants, a culture of collaboration made many of these projects successful. It was also understood by everyone involved that collaboration was key to success, as stated by people involved in the process:

> "If they would have tried it individually or on their own they could have possibly not gotten it done, or had some projects turned down... By working together, CapX2020 presented a much stronger picture to MISO and the states that they were in that this was a good idea, and even though it was a lot of money, there was a believability to the work that they did." (Mike Gregerson of the Great Plains Institute)[77]

> "It was important to deal with it as a group because it was an area-focus, a regional focus. Not any single utility by itself. We found the needs that were emerging and that were in front of us, and we saw that worsening as we modeled the future. We had needs for supporting the energy policy direction of our set of states, and were working to figure out how to incorporate renewable energy into the mix. We had local area reliability needs, we had community support needs...a fully array of needs, and our philosophy was to find the most efficient mix of projects to meet the full array of needs in front of us. Part of that willingness means, 'I win and I let you win too.' Xcel Energy could say, 'Well, I could do it all myself, I've got enough money.' If we wanted to do that, to say we're the big dog...well, maybe we could, but it doesn't really make sense to do

74 Grid North Partners, "Projects," accessed January 5, 2024, https://gridnorthpartners.com/projects/.

75 Xcel Energy, *In the Matter of the Application of Great River Energy, Northern States Power Company (d/b/a Xcel Energy) and Others for Certificates of Need for Three 345 kV Transmission Lines with Associated System Connections*, MPUC DOCKET NO.: ET-2, E002, et al./CN-06-1115, December 2012, at 3, https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={C6E12EA1-091F-430A-9D2F-3D68E5FB234B}&documentTitle=201212-82084-01.

76 *Id.* at 2-3.

77 Monti, M., et al, "Transmission Planning and CapX2020: Building trust to build regional transmission systems," Humphrey School of Public Affairs, University of Minnesota, April 2016, at 59 ("Transmission Planning and CapX2020"), https://gridnorthpartners.com/wp-content/uploads/2021/03/uofm-humphrey_capx2020_final_report.pdf.

that. We asked ourselves, does it help the cause long term? Does it allow for us to meet our collective goals? Does it just bring about a bunch of future fights? If you look at these things with a logical business perspective, in my mind, it makes logical business sense to work together." (Teresa Mogensen, Senior Vice President of Transmission at Xcel Energy)[78]

North Dakota Public Service Commissioner Brian Kalk pointed out, "If you're going to try to build 345-kV lines of this size and scope, maybe Xcel Energy could do it alone. Maybe. But without some of the smaller cooperatives involved, they could never build a line like this. What you'd end up having instead of one transmission line they could all work with, you would have a hodge-podge system of transmission lines in different areas...I think the best way to do transmission planning is this way, because then the cost can be shared by others, as well as doing more efficient planning."[79]

CapX2020 has been characterized as "a great example of how joint ownership in the upper Midwest can harness the collaboration of eleven utilities, their regulators and the public to expand the transmission grid to meet increased demand and support renewable energy development."[80]

MISO Multi-Value Projects (MVPs)

Subsequent to CAPX2020, MISO produced the Regional Generator Outlet Study (RGOS). The study was an outcome of the Upper Midwest Transmission Development Initiative, a collaborative effort involving MISO and a group of Midwest states, including some CAPX participants. RGOS identified specific lines that would enable delivery of new generation to loads owning or contracting for that generation.[81] The Midwest Governors Association, the Upper Midwest Transmission Develop Initiative, and the Organization of MISO States supported the effort. There were ultimately 17 lines planned, at an estimated cost of $5.2 billion, with estimated benefits of almost $1.3 billion annually over the first 40 years of service.[82] The portfolio of lines resolved "reliability violations on approximately 650 elements for more than 6,700 system conditions and mitigating 31 system instability conditions," and enabled 41 million MWh of wind energy per year.[83] Collaboration was extensive with transmission owners providing information about viable routes and corridors, evaluating network and local impacts of various grid topologies, and with states and the RTO involved in evaluating and weighing options throughout the planning and study process. Collaboration also included a member agreed upon cost allocation, allowing the RTO to broadly distribute and recover costs from across its footprint in a manner commensurate with costs. This successful effort occurred prior to Order No. 1000 implementation.

78 *Id*. at 13.

79 *Id.* at 59.

80 WPPI Energy, 141 FERC ¶ 61,004, at p. 61,014 (2012) (Comm'r Norris, concurring).

81 *See* MISO, *Regional Generation Outlet Study,* November 2010, https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf.

82 MISO, *Multi Value Project Portfolio Results and Analyses*, January 2012, at 1-2, https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf.

83 *Id.*

MISO Long Range Transmission Plan Tranche 1

The current MISO Long Range Transmission Planning (LRTP) Process arose out of MISO's reliability imperative, which identified significant resource changes occurring within MISO's footprint and associated operational, market, and transmission challenges.[84] The LRTP process represents proactive, scenario-based, multi-value planning that includes broad cost allocation determined on a voluntary basis. The metrics chosen as a part of the benefits quantification were the result of stakeholder negotiations and collaboration with RTO member utilities.[85] The LRTP process has taken significant collaboration among MISO's transmission owners. To start the planning process, MISO developed future scenarios for its models. As a part of the scenario development, MISO surveyed all its transmission owners. Surveys provide insight into utility resource plans which can then support and guide the modeling assumptions and also provide justification towards the futures scenarios.[86] Throughout the initial stages of the planning there was collaboration and participation by the transmission owners in development of futures scenarios, collection and review of stakeholder survey assumptions, development of study assumptions, and participation in MISO working group meetings.[87] During the modeling and study period of planning there was also significant collaboration between MISO and the Transmission Owners. Transmission Owners and stakeholders reviewed models, helped develop project concepts, evaluated and provided feedback on the proposed project concepts, and participated in multiple workshops. Transmission owners specifically collaborated with MISO on existing local infrastructure, past mitigation discussions and concepts evaluated, details of limiting equipment, etc., all of which is made possible by engagement of those with the local history and experience of their systems.[88] This process for MISO has culminated with the approval of Tranche 1, a $10.3 billion transmission expansion plan of 18 lines totaling approximately 2000 miles that will connect over 50 GW of new resources.[89] Tranche 1 builds on previous examples of collaboration with local utilities and transmission owners. MISO was able to identify "low hanging fruit" options for regional capacity expansion through maximum use of existing right of ways, which resulted in a portfolio that garnered significant stakeholder support.[90] Extensive collaboration with the utility owners of those rights of way was necessary to identify these opportunities to upgrade their delivery capacity.

Grid North Partners Transmission Project Upgrades

Grid North Partners is the new name for the CAPX2020 utilities, which have continued their collaboration efforts after the success of the CAPX2020 projects. The group is composed of 10 utilities that are a mix of IOUs, cooperative, and municipal utilities. In 2023, these utilities identified 19 transmission projects and upgrades across 530 miles of largely existing transmission lines costing $130 million. The projects include mostly transmission line and

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84 MISO, "Reliability Imperative," accessed January 5, 2024, https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/#:~:text=The%20Reliability%20Imperative%20is%20the,reliability%20in%20the%20MISO%20region.

85 ITC Holding Staff, email to authors, October 26, 2023.

86 *Id.*

87 *Id.*

88 *Id.*

89 MISO, *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1*, 2022, at 2, https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf

90 ITC Holding Staff, email to authors, October 26, 2023.

substation upgrades, along with some second circuits.[91] The purpose of the lines is to reduce congestion and allow more renewable energy to be delivered to load. Grid North released a joint statement announcing the lines saying, "[w]e have individually made several improvements to our systems to reduce congestion, but working together has allowed us to holistically study the system and identify these additional 19 solutions that can be quickly implemented on a coordinated basis," Grid North Partners said in a joint statement. "This work will help us maintain reliable service, keep electric prices low and achieve clean energy goals for customers and members."[92] As a result of initial collaboration during the CAPX2020 planning process, the utilities involved know each other's systems well and are able to work collaboratively to provide the best information for modeling and work together to develop a plan that optimizes the system based on deep local knowledge.[93] Grid North Partners is continuing to collaborate, recently releasing its 2050 Transmission Vision report together, to help stakeholders and policymakers better understand the issues and potential solutions for the grid in the coming decades.[94]

American Transmission Company

The American Transmission Company (ATC) is an example of corporate restructuring fostering collaborative transmission planning by taking advantage of the combined experience, knowledge, and expertise to build transmission across what were previously independent utilities. ATC originated in 2000 through divestiture and merger of the transmission assets of four Investor-Owned Utilities (IOUs) and one public power utility. Its establishment was a response to Wisconsin legislation addressing reliability concerns, enacted in October 1999. A primary objective of the new organization was to achieve the benefits of greater coordination to enhance system planning, construct necessary transmission facilities, and ensure a more reliable system. Four utilities — Wisconsin Electric Power Company, Madison Gas & Electric Co., Wisconsin Public Service Corp., and Wisconsin Power & Light Co. — transferred their transmission assets to ATC. In return, these utilities received 50 percent of the assets' value in cash and the remaining portion as ownership interests in ATC. Concurrently, Wisconsin Public Power Inc. (WPPI Energy), a public power utility without transmission assets, acquired ownership interest in ATC based on WPPI Energy's proportional electric load share in Wisconsin. ATC's ownership structure now comprises 28 members, including five investor-owned, 17 municipal, and six cooperative utility owners. Annually, ATC conducts a comprehensive transmission system assessment across its members. The 2023 assessment identified a requirement for just over $7 billion in projects over the next decade.[95] ATC's ownership structure allows for extensive and seamless collaboration across what was previously several separate systems thereby capturing the value of broader multi-utility planning.

91 Grid North Partners, "Grid North Partners utilities to implement 19 electric transmission upgrades to reduce system congestion," October 11, 2023, https://gridnorthpartners.com/wp-content/uploads/2023/10/Congestion-projects-press-release-Grid-North-Partners-2023.pdf.

92 T&D World, "Grid North Partners Identify 19 Transmission Project Upgrades to Reduce Congestion," October 2023, https://www.tdworld.com/overhead-transmission/article/21275580/grid-north-partners-identify-19-transmission-project-upgrades-to-reduce-congestion.

93 Great River Energy Staff, interview with the authors on October 5, 2023.

94 *See* Grid North Partners, *CapX2050 Transmission Vision Report*, March 2020, https://gridnorthpartners.com/wp-content/uploads/2021/02/CapX2050_TransmissionVisionReport_FINAL.pdf

95 APPA at 2-3.

Indiana Joint Transmission System

The Indiana Joint Transmission System (JTS) provides the collaborative benefits described above that can be achieved through corporate restructuring. The JTS is an integrated network spanning two-thirds of Indiana, a section of Ohio, and a small part of Kentucky, encompassing around 7,500 miles of transmission lines. Duke Energy Indiana, Duke Energy Ohio, Wabash Valley Power Association (WVPA), and Indiana Municipal Power Agency (IMPA) are joint owners of this system. IMPA entered the JTS in 1985 by acquiring transmission facilities from Public Service Company of Indiana (PSI) after years of negotiations. This move was prompted by PSI's financial troubles during the construction of the Marble Hill nuclear plant. Although IMPA declined to invest in Marble Hill, it proposed investing in PSI's transmission assets. In November 1985, IMPA finalized ownership and licensing agreements with WVPA and PSI. These agreements stipulate that each utility owns specific lines and substations in the JTS but has shared rights, akin to tenants in common, over the use, output, and capacity of the entire system. Duke Energy Indiana, Duke Energy Ohio, WVPA, and IMPA collaboratively plan JTS transmission upgrades and expansions. The planning group utilizes total load growth forecasts to identify areas requiring new transmission infrastructure. Ownership of specific capacity additions is then allocated among the utilities based on each one's percentage of total load. Each utility contributes investment funds for its assigned portion, aiming to maintain a proportional relationship between their investment and usage of the system.[96]

Missouri River Energy Services, Otter Tail Power, and Great River Energy

Voluntary contractual arrangement can offer similar collaborative outcomes. In 1986, Otter Tail and Missouri River Energy Services (MRES) created a joint transmission system. MRES acquired an 11 percent stake in Otter Tail's transmission system and Otter Tail Power is responsible for operating and maintaining the transmission system. Both utilities collaboratively plan for system expansions and upgrades. Otter Tail also has a separate transmission system agreement with Great River Energy (GRE). Under the Otter Tail Power and MRES agreement, each utility owns specific transmission assets, generally proportionate to its share of the load in the system's service area. Both utilities have usage rights on the system. As the integrated systems of the three utilities partially overlap, these agreements grant each utility the right to use the overlapping portions of the integrated transmission systems as if they were its own.[97] All three utilities were a part of the CAPX2020 projects and collaborative planning process described above.

NEW ENGLAND AND NEW YORK

New England East-West Solution (NEEWS)

The New England East-West Solution consists of a series of four transmission projects developed over a nine-year span from 2008 to 2016. The $1.5 billion in investments in

96 *Id*. at 3-4.
97 *Id*. at 4-5.

Connecticut, Massachusetts, and Rhode Island were designed to improve overall regional reliability and deliver lower cost power to ratepayers by improving east to west power flows.[98] The solutions identified by the utilities consisted of four components known collectively as the NEEWS projects. These four components were the direct result of a regional transmission planning effort which combined a comprehensive regional transmission study with a comprehensive four-component regional transmission solution.[99] The need for these projects was initially identified by a joint ISO-NE-utility working group in 2008 in the Southern New England Transmission Reliability (SNETR) Report Needs Analysis.[100] Northeast Utilities (NU), National Grid USA (NGRID), and later NSTAR worked collaboratively with ISO-NE as a part of a continuation of the ISO-led working group on the planning, modeling, and development of the transmission solutions.[101] The SNETR study, on which NU and NGRID collaborated, highlighted significant transmission needs which the utilities and ISO-NE worked to develop comprehensive solutions.[102] Most of the project work occurred on narrow rights-of-way and required detailed coordination, particularly on outages during construction, with some outages having to be scheduled six months in advance.[103]

Eastern Connecticut Needs Assessment Reliability Upgrades

In 2019, ISO-NE released the Eastern Connecticut Needs Assessment study that identified a significant number of reliability transmission needs that were time sensitive in the Eastern Connecticut region. Given the time-sensitive nature of the reliability needs, ISO-NE immediately began a solutions study process that was reflective of earlier, pre-Order No. 1000 collaborative planning processes. ISO-NE created a study group with several transmission owners including Eversource, National Grid, and CTMEEC to work collaboratively on potential solutions. William Quinlan, President of Transmission and Offshore Wind Projects at Eversource Energy, one of the participating transmission owners described the solution development process in an affidavit, "[t]he study group developed two portfolios of solution alternatives, refined the project components using an iterative process over the course of many months, and ultimately recommended the selection of a portfolio of solutions that included the conversion of several 69 kV facilities already slated for replacement to 115 kV an example of the right-sizing approach .... Eversource anticipates delivering its project components on-time (by late 2023) and on-budget."[104]

Vermont Electric Power Company

Vermont Electric Power Company (VELCO) is another example similar to ATC, of corporate restructuring fostering collaborative transmission planning. VELCO was founded in 1956 by

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98 Power Engineers, "New England East-West Solution (NEEWS) 345 kV and 115 kV Projects," accessed January 5, 2024 ("Power Engineers"), https://www.powereng.com/library/new-england-east-west-solution-neews-345-kv-and-115-kv-projects.

99 ISO New England, *New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment*, Southern New England Regional Working Group, April 2011, at 6, https://portal.ct.gov/-/media/CSC/1_Dockets-medialibrary/Docket_424/424_Application/V5ex4InterstateCSCApplicationComponentUpdatedNeedsAssessmentpdf.pdf.

100 *Id.* at 1.

101 *Id.*

102 *Id.* at 6.

103 "Power Engineers."

104 DATA Group, Comments of Developers Advocation Transmission Advancements, RM21-17, pg 31, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=dcc9c45e-60ee-ce89-8e0f-82ac9b400001.

the state's investor-owned utilities with the aim of creating an integrated transmission system. Initially, VELCO's transmission lines helped efficiently transport newly available St. Lawrence hydropower into Vermont from New York. In the 1960s, the Burlington municipal utility joined VELCO as a condition linked to nuclear plant licenses, addressing antitrust law concerns. In the late 1970s, an agreement permitted all of Vermont's municipal and cooperative utilities to acquire shares in VELCO. As demand for services increased and in response to the 1970s oil embargo, VELCO's role expanded and it began acting as the agent for out-of-state power contracts on behalf of Vermont's utilities, resulting in cost savings and enhanced reliability through improved interconnected operations. Over time, Vermont's 15 municipal and two cooperative utilities increased their shares in VELCO, achieving a load ratio ownership share in 2001. When VELCO requires new equity for its capital program, each shareholder can invest a proportionate amount based on its load ratio. Shares are owned by individual municipal utilities, with many obtaining financing from the Vermont Public Power Supply Authority, the state's joint action agency. VELCO is obligated to publish a Long-Range Transmission Plan every three years, projecting 20 years into the future. This plan serves as a basis for a collaborative process involving all Vermont utilities and stakeholders through the Vermont System Planning Committee. The objective of this collaborative process is to ensure thorough, equitable, and timely consideration of alternatives to building transmission, particularly when viable alternatives can meet identified reliability needs. The process also integrates public participation and outreach at each stage of the planning cycle.[105]

New York Transco

NY Transco is a joint venture among the New York investor-owned utilities which was formed to improve regional transmission development in New York.[106] The idea for NY Transco originated in 2011 with a long-term coordinated transmission planning effort among the New York transmission owners, called the State Transmission Assessment and Reliability Study (STARS) studies, which identified regional bulk transmission expansions needed across the state.[107] After collaborating on a shared vision for long-term transmission needs, Con Edison, National Grid, Avangrid, and Central Hudson agreed to form NY Transco as a vehicle to advance these projects. In 2016, NY Transco was formed, and its initial projects, almost 50 miles of new 345 kV lines and upgrades, were to be approved as a result of the New York Public Service Commission's (NYPSC) proceeding to prepare for the retirement of the 2,060 MW Indian Point nuclear power station. Notably, one project involved stringing a second 345 kV circuit on existing utility-owned towers that were planned for a double circuit in the 1970s. In 2023, NY Transco completed the $600 million New York Energy Solution and the Rock Tavern to Sugarloaf projects, which were intended to relieve historic congestion from upstate to downstate New York. The transmission solutions NY Transco have worked on utilize existing rights of way and require collaboration with the existing transmission owner. For example, 55 miles of a 345 kV circuit in the New York Energy Solution used an existing 115 kV right-of-way by relocating the two 115 kV circuits to new monopole towers along with the new 345 kV

105 APPA at 2-3; Vermont Electric Power Company, "Who We Are," accessed January 5, 2024, https://www.velco.com/about/history; Vermont Electric Power Company, "Planning," accessed January 5, 2024, https://www.velco.com/our-work/planning.

106 Con Edison staff, emails to authors, January 12-17, 2024.

107 *See* STARS Technical Working Group, "New York State Transmission Assessment and Reliability Study Phase II," April 2012, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B80A6B032-AE87-4C14-A660-1C2B4D0523F0%7D.

circuit.[108] Most recently, NY Transco, together with the New York Power Authority, was selected to build the Propel Energy NY project that will increase transfer capability between Long Island and New York City and the rest of the State to allow for more delivery of offshore wind power. This is a $3.2 billion project that will involve two 345 kV submarine lines across Long Island Sound, three 345 kV underground lines and one 138 kV underground line on Long Island, and several new and upgraded substations.[109] The NY Transco partnership demonstrates the benefit of collaboration among multiple local transmission owners to advance cost-effective projects utilizing the existing system while managing impacts to surrounding communities and the environment.

PJM

PJM EHV System[110]

"Extra-High Voltage" or EHV is typically used to refer to a general class of transmission lines, usually over 345 kV or 500 kV. However, in this case, EHV refers to a specific 500 kV transmission project collaboratively planned and constructed by PJM Pool members in the late 1960's and 1970's under a contract known as the EHV Agreement. The transmission projects connected approximately 3.5 GWs of mine-mouth coal generating units at Keystone and Conemaugh in western Pennsylvania to the PJM Pool. These projects were the result of collaborative planning between all the PJM Pool members[111] who were driven to plan for these projects due to the economies of scale and fuel price differentials. During the collaborative planning process for the new EHV facilities, the PJM Pool members and Allegheny Power System (AP) agreed to interconnect the proposed EHV System with the 500 kV network being developed by AP. This new connection between the PJM Pool and AP meant an increase in the ability of the two regions to exchange power and thereby benefit from pooling on an interregional basis. All the companies involved also collaborated on a voluntary cost allocation method to which all participants agreed.

Susquehanna-Roseland Transmission Line[112]

This $1.4 billion, 146-mile 500 kV transmission line from Pennsylvania to New Jersey was built in 2015. The line was built to meet reliability needs after 23 violations of NERC criteria were found. After construction, congestion in the PSEG zone was almost eliminated, providing significant value to consumers. Planning began in 2007 when the need was identified. It was finally completed in 2015 after permitting delays. PPL and PSEG collaborated extensively on the project, as there were many options for the network expansion, each with significant network

108 Author communications with Con Edison staff, January 12-17, 2024.

109 Propel NY Energy, "Fact Sheet," accessed January 27, 2024, https://static1.squarespace.com/static/621797f51f11ca0489f2df6e/t/653fc63b74e1ce5ffe7b1ed8/1698678332649/PropelNYEngergy_6.23_v5_FactSheet.pdf.

110 The description of the EHV System upgrades relies on the Affidavit of Robert N. Spencer, Director of Interconnection Arrangements for PECO, on behalf of the Responsible Pricing Alliance, FERC Docket EL05-121-000 (November22, 2005).

111 From 1927 to 1997, PJM was a power pool (the "PJM Pool") created through a contract (the "PJM Agreement") among a group of electric utility companies (ultimately eight in number). These were Public Service Electric and Gas Company, PECO, Pennsylvania Power & Light Company, Baltimore Gas and Electric Company, General Public Utilities Corporation (through its operating subsidiaries Pennsylvania Electric Company, Metropolitan Edison Company, and Jersey Central Power & Light Company), Potomac Electric Power Company, Atlantic City Electric Company, and Delmarva Power & Light Company.

112 Information on the Susquehanna-Roseland Project relies on interviews with PSEG staff, with the authors, October 2, 2023.

impacts in both the PPL and PSEG integrated transmission systems. The two transmission owners had a combined operations office for the project and a joint team housed in the same office. The joint team considered eight alternative routes and had to overcome permitting challenges for the segment of the line crossing the Delaware Water Gap National Recreation Area crossing, along with many other local issues. Development costs were shared between the two utilities. During all stages of the project, the utilities shared information and coordinated efforts related to s their contracts for construction, design, and environmental assessments. Through collaboration the utilities evaluated and pursued an innovative approach to foundation design, rock and silt fence design and helicopter installation of the monopoles/lattice structure.

SOUTHEAST AND TEXAS

Acadiana Load Pocket (ALP) Project[113]

The Acadiana Load Pocket (ALP) Project was initially developed in 2009 by three utilities, Cleco Power (Cleco), Lafayette Utilities System (LUS), and Entergy Gulf States Louisiana (EGSL). It was a $200 million investment in both new transmission lines and substations. The project was identified through a joint study with SPP and addressed a variety of reliability and economic considerations related to serving a load pocket in south-central Louisiana along the seams of all three utilities. The joint study uncovered an overreliance on inefficient units within the ALP, a disconnect between long term modeling and actual operations, power flow model corrections, and a lack of operational flexibility. Each utility was individually responsible for constructing components of the ALP Project in a way that is roughly commensurate with benefits it received. For the economic benefits of the project, Cleco was determined to be the main beneficiary (over $900 million in fuel cost savings) and therefore constructed the majority of those facilities. An analysis done by the Brattle Group showed that there were six key lessons that could be learned from the project: 1) General agreement that there was a problem that needed to be addressed and that a seams solutions could provide both individual and joint benefits; 2) It was recognized that needs and drivers were different for the parties involved; 3) Transmission planning and cost allocation was jointly considered; 4) Cost allocation via transmission ownership, not financial transfers, was easier to accomplish; 5) Utilities were responsible for recovering costs through their own tariff; and 6) Strong state-level participation.[114] On the cost allocation point, Brattle explained, "cost allocation via transmission ownership (not financial transfers) was easier to accomplish. Especially for non-market regions and utilities, financial transfers may not even be possible or prove difficult to implement. For the ALP Project, each entity shared costs by building, owning, and maintaining a different segment of the buildout."[115]

113 Pfeifenberger and Hou, Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning, prepared for SPP Regional State Committee, April 2012 (SPP RSC report), https://hepg.hks.harvard.edu/files/hepg/files/spp_seams_report_2012-04-16_sent.pdf.

114 Pfeifenberger, J., K. Spokas, J. Hagerty, J. Tsoukalis,, "A Roadmap to Improved Interregional Transmission Planning," November 2021, at 37 ("Roadmap to Improved Interregional Transmission Planning"), https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf.

115 *Id.*

Georgia's Integrated Transmission System

Georgia's Integrated Transmission System (ITS) is an example of joint asset ownership, encompassing 90 percent of the state and comprising nearly 18,000 miles of transmission lines jointly owned by four electric utilities. These utilities include Georgia Power Co., a subsidiary of Southern Company; Georgia Transmission Corp., an affiliate of Oglethorpe Power Corp., a generation and transmission cooperative; Municipal Electric Authority of Georgia (MEAG Power), a municipal joint action agency; and Dalton Utilities, a municipally owned utility. In this collaborative framework, Georgia Power maintains separate two-party agreements with each of the three other transmission owners, alongside supplemental agreements pertaining to the operations and maintenance of the transmission system. While each utility owns individual transmission assets, they collectively use all transmission facilities in the system to serve their respective customers. The operation of the transmission network is overseen by Georgia Power, with each utility bearing the operation and maintenance costs of the lines it owns. To ensure equitable ownership, each owner maintains an investment in transmission aligned with the investments of the other joint owners. Planning is performed collaboratively by all four utilities, and a parity formula, calculated annually and generally based on each system's five-year rolling average peak demand, only includes transmission facilities in service and approved by all owners.[116]

North Carolina Transmission Planning Collaborative (NCTPC)

North Carolina Transmission Planning Collaborative (NCTPC) was established in 2005 by the state's major electric load-serving entities, Duke Energy Carolinas' (DEC), Duke Energy Progress' (DEP), ElectriCities of North Carolina (munis), and the North Carolina Electric Membership Corporation (co-ops). The goal was to create an integrated long-term transmission expansion plan between DEC and DEP transmission systems in North Carolina and South Carolina as well as enhance transmission planning by allowing all stakeholders to participate in transmission planning.[117] The NCTPC annually develops a single, coordinated transmission plan for all its members. The NCTPC's 2022-2032 Collaborative Transmission Plan identified 38 major transmission projects[118] across all members, representing a $1.49 billion investment over the next decade. The plan includes 24 reliability and 14 public policy projects.[119] The North Carolina commission and stakeholders supported the study results and the final NCTPC 2022-2032 Collaborative Transmission Plan. For DEC and DEP, 14 projects called the Red Zone Transmission Expansion Plan were identified and included in the 2022-2032 Collaborative Transmission Plan to maintain reliability as well as eliminate barriers to interconnecting new resources, mainly solar, in both South Carolina and North Carolina. These projects are an almost $500 million investment, estimated to interconnect over 3,700 MW of solar-generation.[120] Since NCTPC's creation in 2005, the annual collaborative plans have identified transmission projects totaling

116 APPA at 4.

117 *See* North Carolina Transmission Planning Collaborative, accessed January 27, 2024, http://www.nctpc.org/nctpc/ ("NCTPC").

118 Major projects are $10 million or more. *See* ElectriCities of North Carolina, "2022 Collaborative Transmission Plan Identifies 38 Major Transmission Projects 24 Reliability Projects and 14 Public Policy Projects, April 2023 ("ElectriCities of North Carolina"), https://www.electricities.com/press-releases/2022-collaborative-transmission-plan-identifies-38-major-transmission-projects-24-reliability-projects-and-14-public-policy-projects/.

119 North Carolina Transmission Planning Collaborative, "Report on the NCTPC 2022–2032 Collaborative Transmission Plan," February 2023, at 2-6, http://www.nctpc.org/nctpc/document/REF/2023-02-21/2022%20NCTPC%20Report%2002_21_2023_FINAL.pdf.

120 Duke Energy staff, email to authors, January 10, 2023.

almost $3 billion through 2022, with almost $300 million deferred until after 2032 or cancelled as a result of changing transmission system requirements.[121] The 2023-2033 Collaborative Transmission Plan is even larger identifying $2.4 billion in transmission upgrades.[122] The NCTPC is open to all interested stakeholders and includes a formal process for input through the Transmission Advisory Group (TAG).[123] In recent years, the North Carolina Transmission Planning Collaborative has worked well allowing for meaningful input and collaboration between utilities and stakeholders.[124] According to Marty Berland of ElectriCities of North Carolina, Chairman of the NCTPC Oversight/Steering Committee (OSC), "The NCTPC provides a valuable function by allowing stakeholders to better understand the electric transmission planning process. By offering greater transparency and opportunity to provide input to the process, entities that rely on the transmission system can collaborate to develop plans for future enhancements in a manner that optimizes cost effectiveness and reliability."[125]

Texas Competitive Renewable Energy Zones

The Texas Competitive Renewable Energy Zones (CREZ) is an example of collaboration even though the lines were built out to a part of the state where there was almost no existing transmission system, and it used a competitive process to bring in investors to these new areas. All of the transmission owners were actively engaged in a process led by the PUC of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT). The process was directed by legislation to designate new CREZs along with the needed transmission.[126] After studying the wind potential in Texas, the PUCT in 2007 approved 5 CREZs. The PUCT also opened a proceeding and sought transmission plans from ERCOT and stakeholders to connect wind resources from these zones in West Texas and the panhandle with load center.[127] The lines were completed by 2013 and included approximately 3,600 miles of mostly new 345 kV transmission lines interconnecting 18.5 GW of new wind resources, representing an almost $7 billion investment.[128] The CREZ transmission projects included almost 2,400 miles of new rights-of-way, largely built out to areas with no existing power grid. These projects were built by a combination of independents and utilities.[129] Broad collaboration among diverse stakeholders was also critical to the success of the CREZ projects. A wide range of stakeholders participated in the PUCT proceedings, including, "incumbent power generators, potential wind developers, both existing and aspiring TSPs, municipal power companies, rural cooperatives, cities, counties, regional and sub-regional coordinating agencies, chambers of commerce and economic development organizations, real estate groups, ranchers and farmers, residential landowners, environmental advocates, and state and federal agencies."[130] ERCOT did much of the technical

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121 "ElectriCities of North Carolina."

122 North Carolina Transmission Planning Collaborative, "Report on the NCTPC 2023–2033 Collaborative Transmission Plan," January 2024, at 2-8, http://www.nctpc.org/nctpc/document/REF/2024-01-19/2023%20NCTPC%20Report%201_19_2024_FINAL_DRAFT.pdf.

123 NCTPC.

124 CCEBA, "A Look Back at CCEBA's Work in 2023," December 2023, https://carolinasceba.com/a-look-back-at-ccebas-work-in-2023/.

125 "ElectriCities of North Carolina."

126 SB 20, "An Act Relating to this State's Goal for Renewable Energy," 79th Legislature, Special Session, Texas Utilities Code §36.053 (passed July 20, 2005).

127 J. Cohn and O. Jankovska, "Texas CREZ Lines: How Stakeholders Shape Major Energy Infrastructure Projects," Center for Energy Studies, (November 2020), at 10-11 ("Center for Energy Studies"), https://www.bakerinstitute.org/sites/default/files/2020-11/import/ces-pub-texascrez-111720.pdf.

128 W. Lasher, "The Competitive Renewable Energy Zones Process," ERCOT, 5-8 (August 2014) https://www.energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf.

129 *Id.* at 3; "Moving Beyond Paralysis" at 4.

130 "Center for Energy Studies" at 20.

planning work for CREZ and also had significant stakeholder collaboration through its Regional Planning Group (RPG). For example, while developing the Transmission Optimization Plan in response to the PUCT's CREZ designations stakeholders in the RPG reviewed "modeling assumptions, equipment costs, and modeling results."[131] The RPG also sought input from existing and potential transmission owners and other market participants, and the RPG invited vendors to meetings to present on the technical capabilities of different transmission technologies, such as HVDC and 765 kV transmission lines.[132]

131 ERCOT, "Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study," April 2008, at 2, https://www.nrc.gov/docs/ML0914/ML091420467.pdf.
132 *Id.* at 2.

6 COMMON ELEMENTS OF SUCCESSFUL TRANSMISSION EXPANSION EFFORTS

For this report, we reviewed a number of transmission planning documents and interviewed a variety of experienced transmission planners to investigate how collaboration takes place and what information must be shared to drive successful transmission expansion. Our interviews revealed that common features of successful planning experiences include:

- robust information sharing,
- voluntary collaboration by willing participants,
- shared cost allocation and recovery, and
- upfront certainty and agreement on project ownership.

Policymakers and industry stakeholders can draw valuable lessons from these common elements.

INFORMATION SHARING

All of the successful examples identified in Section V included extensive information sharing. Our expert interviews with key parties involved in these examples further highlighted the importance of information flow across multiple entities to drive successful transmission expansion. The list below compiles the types of information that must be shared. It is important to note that much of this information is proprietary to the transmission owners and would also likely be considered competitively sensitive in a competitive transmission development framework. Types of information include:

- Specific towers, conductors, or other grid technology and specifications/standards used by a utility, including the overall configuration of the system.
- Generation data including maximum capacity, unit type, commission date, retirement date, bus, minimum capacity, maintenance required hours, forced outage rate, forced outage duration, minimum downtime, minimum run time, must run status, and ramp rates.
- Alternative routes that may be possible given existing grid capacity or unused easements
- Internal policy related to different types of land (i.e., federal and state lands, wetlands, etc.)
- Access road policy and development (i.e., how to protect roads from washing out)
- Specific materials used in development (types of rock, silt fences, etc.)
- Potential innovations (i.e., new foundation design, more compact line design, etc.)
- Institutional knowledge and history, such as past mitigation discussions and concepts evaluated or attempted.

- Local history and experience of their system.
  - Interactions with distribution system
  - Geographic information
  - Knowledge of landowners and local community
- Utilities' longer-term system plans, including what utilities have planned to address local reliability, accommodate new load additions, and other long-term modifications required to achieve a target system configuration.
- Data associated with specific upgrade costs, ratings, and lead time estimates to better facilitate long-term regional transmission planning and scenario-development efforts (e.g., how much do utilities expect it to cost to develop certain types of assets in different parts of their service territories).
- Substation expansion capabilities (e.g., available bays and owned property) and right-of-way expansion capabilities.
- Current system limitations, including particular limiting elements like relays or bus terminations, rather than larger constraints like line capacity.
- Flow patterns on the system, and how they are changing.
- Asset condition that can only be gained from being responsible for operating and maintaining the system on a day-to-day basis.
- Operating procedures for some of the more complex assets, configurations, and operating environments.

Information sharing can occur between a few or a lot of entities. For example, given the large number of utilities in MISO, the RTO conducts surveys of its participating transmission owners as a part of its LRTP scenario development. These surveys allow MISO to better understand the current and future needs and grid conditions of each member.

VOLUNTARY NATURE OF COLLABORATION

Almost all of the collaboration and resulting partnerships are voluntary. Parties came together when they had common interests and objectives. Their incentives may have varied and the types of benefits they received often varied such as in the case of municipals, cooperative, and investor-owned utilities working together. But the benefits of shared networks and regional power exchange, as well as the inability of any one entity to fully build or own the totality of the identified facilities drove the collaboration.

Collaborating parties' needs and benefits often varied as well. Collaborative planning often addressed multiple concerns and interests, and realized mutual benefits even when the initial needs might not have been the same for all parties. For example, when looking at the Acadiana project, the three utilities involved had different systems needs that the planned upgrades were able to solve. The Tehachapi area transmission projects are another example, where the initial proposal was focused on the need to interconnect new generation, but during the planning process the reliability, economic, and public policy benefits to other transmission owners in CAISO were recognized.

SHARED COST RECOVERY AND COST ALLOCATION

Cost allocation and recovery was another common aspect of collaborative planning. Since appropriate allocation of costs for recovery is such a formidable barrier to transmission, it was an important reason for parties to collaborate. When some utilities were able to receive partial cost recovery through a state PUC, and others were able to fund transmission investment through their rates or separate subscriptions for line capacity, funding sources were pooled together in a way that no individual entity could. For example, for its Energy Gateway projects, PacifiCorp received cost recovery approval from all six of the state PUCs where it operates. The same was true for the Colstrip line in the Northwest. In RTO regions, active state participation in cost allocation has helped achieve consensus and avoid litigation. States were very active in the planning and development of the MISO MVPs as well as SPP's Priority and Balanced Portfolio projects, which was particularly helpful for the cost allocation processes.

Cost allocation is also critical for the participation of municipal and cooperative utilities. As the TAPS group noted in comments to FERC for its transmission planning NOPR, "LSEs within a TO's footprint are likely to be public power or non-profit cooperatives that inherently satisfy the following criteria: (1) they use their net transmission project earnings to offset their customer costs; and (2) their participation otherwise reduces costs to consumers in the TO's footprint."[133] For Munis and Coops, ownership in lines is critical and allows the utilities to participate and support planning processes. The support of Munis and Coops can be important to the success of regional plans. One cooperative utility explained to the authors that ownership of the line was important to them and was critical to their support and participation in the process of MISO planning.[134]

In the RTO examples discussed above, the certainty of cost allocation and recovery came through the ISO or RTO tariff. The tariff provided a vehicle for funds to be collected from wholesale customers in the case of the SPP Priority Projects, SPP Balanced Portfolio and Priority projects, and the MISO MVPs, and New England, CAISO, and PJM investments all benefited from the regional tariff as a cost recovery mechanism. Typically, the cost allocation provided through an RTO tariff is for relatively broad allocation of costs, aligned with the relatively broad set of beneficiaries who tend to benefit from large regional network lines.

CERTAINTY AND AGREEMENT ON PROJECT OWNERSHIP

A factor in common across all the examples above was a mutual agreement on who would build and own what portions of transmission projects. Typically, the parties agreed in advance. In most cases, the participants were the sole provider of transmission in an area per state laws

133 Initial Comments of Transmission Access Policy Study (TAPS) Group, FERC Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection Docket No. RM21-17-000, April 17, 2022, at 40, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=7DD0CDE1-86FA-CB2C-930E-82AD12500000.

134 Great River Energy Staff, interview with the authors, October 5, 2023.

or regulations. For example, all but three states in MISO North have implemented state right of first refusal (ROFR) laws prior to the successful approval of major transmission expansion investments. In the various examples above, the munis, coops, and IOUs all had some certainty going in, or developed agreements with other parties on who would own parts of transmission project portfolios. According to APPA, "[p]rojects built as a single undertaking typically include a percentage allocation of the ownership rights and responsibilities, including the resulting incremental transfer capability, to each participating utility based on capital input."[135]

RTO policies can provide some certainty on ownership as well. MISO and SPP both have an 80-20 rule, where if 80 percent of a transmission plan or solution is existing upgrades (as opposed to greenfield), the projects are assigned to the owner of those transmission assets.[136] This type of rule can provide certainty around which entity is building a project and can build trust and facilitate sharing of information, particularly around existing system information. The leaders of one very collaborative interregional transmission project in the middle of the country, Power from the Prairie,[137] explained that ownership certainty is critical for the project, which is HVDC and thus uniquely different from traditional HVAC project, and it will not move forward with all the study, permitting, and other development work if the participants believe ownership might be transferred to others later.[138]

135 APPA at 7.

136 MISO, "Competitive Transmission Update," Planning Advisory Committee, May 2022, 6, https://cdn.misoenergy.org/20220527%20PAC%20Item%2003%20CTA%20Update%20Presentation624804.pdf.

137 Power from the Prarie, "New Electric Grid Infrastructure to Enable Higher Levels of Renewable Energy," accessed January 5, 2024, https://www.powerfromtheprairie.com/.

138 Bob Schulte, email to authors, January 4, 2024.

7 | BENEFITS OF COLLABORATION

The assessment above highlights certain benefits from collaboration that are important to foster and enable needed infrastructure development. These include: the ability to meet multiple needs efficiently, more and higher quality information for planners, better use of existing assets and rights of way, improved coordination of outages during construction, a greater ability to assemble a more efficient suite of technologies, faster development of needed infrastructure, and a higher likelihood of achieving needed consensus. We take these in turn below.

ABILITY TO ADDRESS MULTIPLE NEEDS

A benefit of collaboration between various transmission entities is the ability to address multiple needs together in a more efficient way than each entity addressing single needs with one-off investments. Individual new transmission lines tend to have multiple system benefits, including regional and local reliability, market efficiency, public policy, generator interconnection (GI), and local load growth. Various transmission entities, public and private, may be experiencing different needs at different times. Without collaborating, opportunities to address multiple needs with a unified suite of investments would be missed. Better solutions can be identified with multi-benefit planning that considers plans, needs, and benefits as they are considered by multiple entities.[139]

139 "Transmission Planning for the 21st Century," at 30-58.

Collaboration also enables efficiencies resulting from impacts outside a transmission entity's service area. Individual lines or upgrades tend to have impacts outside of the geographic footprint of a typical transmission owner given the open nature of interconnected transmission systems wherein electric energy moves based on the laws of physics (e.g., loop flows) and there is little ability to direct flows. In a country where transmission ownership is divided across over three hundred owners, the spillover impacts of any upgrade tend to be significant.

Collaboration also enables greater efficiencies between distribution system planning and bulk transmission planning. A collaborative planning process that includes participation by distribution operators helps ensure those effects are fully reflected in the transmission system planning process. CAISO has noted that, "[a]lthough the high-voltage system interconnects with distribution facilities in sole locations, the lower-voltage system has extensive interconnections to the distribution system and is much more integrated with the distribution system. Conditions on the distribution system can more directly affect the low-voltage transmission system and vice versa. This is increasingly becoming true as distributed energy sources continue to grow. Operating and maintaining these lower-voltage facilities thus requires greater coordination between the transmission and distribution systems."[140]

To be sure, many coordination benefits can be achieved by Regional Transmission Organizations, which can integrate these multiple purposes and regional impacts into one coordinated regional plan. However as discussed in the barriers section below, collaboration does not necessarily occur effectively in all RTOs. Often, RTOs define a single need and solicit proposals for that need, without a process of assembling multiple needs and benefits together. They may also have explicit restrictions, or significant disincentives to collaboration as discussed in the barriers section below. And, of course, there are not RTOs in major parts of the country, so other forms of collaboration will be needed there.

The recent uptick in load growth raises the importance of collaborating to address multiple needs. Load growth is rising in much of the country, and it is happening in a way that is hard for any single entity to assess on their own. It varies by local area due to factors such as manufacturing plant and data center additions, plus expectations for end-use electrification and penetration of electric vehicles.[141] Often, the developers of such facilities are unable to publicly share information about their plans. Different parties therefore have different information about potential load growth. Collaboration can ensure that these multiple load-related needs are addressed and coordinated with other needs. For example, load growth in Northern Virginia has significant interactions with plant closures in Maryland, as well as planned and expected offshore wind resource development up and down the mid-Atlantic coast. Some of the same transmission investments can address both issues if they are coordinated. Data center growth is also strong in Georgia, the Pacific Northwest, Illinois, Ohio, Arizona, Iowa, and elsewhere, and manufacturing growth is now returning in certain areas, such as the Southeast, so grid planners will need to integrate dynamic and uncertain load estimates with other system needs.[142]

140 Reply Comments of the California Independent System Operator, FERC Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection Docket No. RM21-17-000, 2022, at 69, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=c447dd64-912f-c004-9dd7-83577ef00000.

141 *See* "The Era of Flat Power Demand is Over," at 8-11.

142 *Id.*

BETTER QUALITY AND QUANTITY OF INFORMATION FOR NETWORK PLANNERS

Collaborative planning improves the information available to transmission planners. The quality of a regional transmission expansion plan is in large part a function of the quality of the data underlying the planning analysis. A highly collaborative process brings together those with the best information and knowledge of each part of the existing integrated system. No single entity possesses the whole picture of the integrated grid. Even regional planners such as RTOs have limited information about local conditions relevant for actual siting and permitting, system dynamics such as shifting load patterns, lower voltage infrastructure, generator retirements and additions, and distribution system resilience needs. Given this fact, effective RTO regional transmission planning requires close collaboration between the RTO planners and RTO transmission owner members. One grid planner observed, "[w]hile SPP regional planners are able to perform studies and recommend projects, they do not have the expertise to actually construct lines or the knowledge regarding operational, environmental, or regulatory challenges in each part of their footprint to develop the best solution."[143]

BETTER USE OF EXISTING ASSETS AND RIGHTS OF WAY

Active collaboration can reduce the need for new rights-of-way (ROW), by bringing options to the table for upgrading existing assets and rights-of-way. Use of existing rights of way can be a much faster and cheaper means of expanding transmission capacity given permitting and NIMBY challenges with new rights-of-way. Using existing ROW also can limit environmental impact by avoiding the need to disturb land on new ROW. Very often, transmission plans are an assembly of substation upgrades and expanded capacity on existing rights of way. Over 80 percent of MISO's recent LRTP Tranche 1 investments were on existing corridors. Whether or not the capacity exists for such a high ratio in the future, those concerned with land impacts and costs of new rights-of-way can gain confidence in the process when such options are actively evaluated and pursued where appropriate. If one looks at typical transmission plans, one can see a long list of small upgrades to substations, transformers, and other small additions to the system rather than a few big new lines as some people might expect. Figure 1 below shows one example of a regional transmission plan from CAISO's 2022-2023 approved plan, where many of the 46 investments are labeled as investments such as "reconductoring," "reinforcement," "reconfiguration," "bus voltage addition," "upgrade," and "replacement"–all of which are only possible through collaboration with existing transmission owners.

143 Affidavit of Jarred J. Cooley, P.E., Director, Strategic Planning at Southwestern Public Service Company, pg. 7 (Aug. 16, 2022) attached as Exhibit 3 to Comments of Developer Advocating Transmission Advancements, FERC Docket No. RM21-17 (August 22, 2022) ("Cooley Affidavit"), https://elibrary.ferc.gov/eLibrary/filedownload?fileid=dcc9c45e-60ee-ce89-8e0f-82ac9b400001.

FIGURE 1 | CAISO transmission upgrades[144]

No.	Project Name	Service Area	Expected In-Service Date	Project Cost (in millions of dollars)
1	Garberville area reinforcement project	Humboldt	2032	204
2	Tulucay-Napa #2 60 kV line Reconductoring project	NCNB	2028	14.6
3	Santa Rosa 115 kV lines Reconductoring project	NCNB	2028	74
4	Tesla 115 kV Bus Reconfiguration Project	CVLY	2030	55
5	Banta 60 kV Bus Voltage Conversion	CVLY	2024	17.5
6	Metcalf 230/115 kV Transformers Circuit Breaker Addition	GBA	2026	15
7	South Bay Area Limiting Elements Upgrade	GBA	2027	11
8	Redwood City Area 115 kV System Reinforcement	GBA	2030	110.8
9	Lone Tree – Cayetano – Newark Corridor Series Compensation	GBA	2027	25
10	Pittsburg 115 kV Bus Reactor project	GBA	2032	26
11	Equipment Upgrade at CCSF Owned Warnerville 230 kV Substation	Fresno	2024	1.6
12	Los Banos 70 kV Area Reinforcement Project	Fresno	2029	60
13	Los Banos 230 kV Circuit Breaker Replacement	Fresno	2032	66
14	Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	Fresno	2032	184
15	North East Kern 115 kV Line Reconductoring Project	Kern	2032	256
16	Mesa 230/115 kV spare transformer	CCLP	2032	24
17	Barre 230 kV Switchrack Conversion to Breaker-and-a-Half	SCE - Main	2026	45
18	Mira Loma 500 kV Circuit Breaker Upgrade	SCE - Main	2026	10
19	Serrano 4AA 500/230 kV Transformer Bank Addition	SCE - Main	2027	120
20	Sylmar Transformer Replace	SCE - Main	2026	23
21	Antelope-Whirlwind 500 kV Line Upgrade Project	SCE - Main	2025	6
22	Coolwater 1A 230/115 kV Bank Project	SCE - NOL	2026	47
23	Control 115 kV Shunt Reactor	SCE - NOL	2026	4
24	Miguel-Sycamore Canyon 230 kV line Loop-in to Suncrest Project	SDG&E	2032	375

144 CAISO, *2022-2023 Transmission Plan*, May 2023, Table 8.2-1 at 167. https://www.caiso.com/InitiativeDocuments/Revised-Draft-2022-2023-Transmission-Plan.pdf.

MORE EFFICIENT SUITE OF TECHNOLOGIES

Greater collaboration with potential project developers, including utilities and competitive developers, will increase the potential for the identification and evaluation of a broader set of technology options. Most investments to achieve grid expansion goals tend to be integrated AC network facilities which have extensive interactions with the existing network and its various owners, so they will need to actively collaborate and support any plan. As discussed above, the electric grid in the US is actually three big, synchronized machines in the country operated by 330 different entities, none of whom control all parts of it. There are also increasing opportunities for high voltage DC (HVDC) investments, high-performance conductors, grid-enhancing technologies (GETs), and various other technologies. Different owners may have different levels of familiarity with these approaches. The collective sum of expertise with new technologies will tend to be higher in a collaborative process compared to each entity planning on its own.

FASTER DEVELOPMENT OF NEEDED INFRASTRUCTURE

Effective collaboration can also increase the speed at which new transmission can be deployed. When the key entities can agree on plans and ownership, that can avoid the two to three year process of competitive selection including the iterations between need identification and modification based on submissions from third parties. One analysis found that "[c]ompetitive solicitations added as many as 1000 days to the development of transmission projects, and many experienced cost escalations, further questioning the value of competitive solicitations."[145] That delay has a real cost in the form of foregone benefits over that period of time. For example, for the MISO LRTP Tranche 1 projects with net benefits of $23 billion to $41 billion, a two-year delay would reduce discounted future net benefits by roughly $3 billion to $6 billion, made up of the production cost, generation capacity, and other savings included in MISO's benefit-cost analysis.[146]

IMPROVED COORDINATION OF OUTAGES DURING AND AFTER CONSTRUCTION

Transmission investment typically requires some existing lines to be taken out of service as installation and integration occurs, sometimes on remote systems. Collaboration with existing system owners is critical to ensure an orderly process of construction and integration of new lines with the existing system. And over the life of the facilities, maintenance will be needed requiring different lines to be taken in and out of service or operated differently.

145 Concentric Energy Advisors, *Competitive Transmission: Experience Shows Order No. 1000 Solicitations Fail to Show Benefits*, August 2022, at 1, https://ceadvisors.com/wp-content/uploads/2022/08/Competitive-Transmission-Experience-To-Date-Shows-Order-No.-1000-Solicitations-Fail-to-Show-Benefits.pdf.

146 This assumes a 6.9% discount rate over twenty years, which was the Weight Average Cost of Capital MISO used in their LRTP Tranche 1 analysis. MISO also calculated the benefits of the projects over 40 years to be a minimum of $53 billion. A two-year delay would forego over $7 billion in discounted net benefits. MISO, "LRTP Tranche 1 Portfolio Detailed Business Case," March 2022, at 16, https://cdn.misoenergy.org/20220329%20LRTP%20Workshop%20Item%2002%20Detailed%20Business%20Case623671.pdf.

MORE LIKELY TO RESULT IN NEEDED CONSENSUS

Regional consensus among utilities, states, and other stakeholders is critical for moving transmission plans forward. To date there is no federal mandate for collaborative transmission planning or RTO membership, and such a mandate is unlikely and unnecessary with the right policies in place. Even where there are RTOs, regional consensus has been necessary for transmission plans and cost allocation to move forward.[147] Collaboration is necessary to achieve sufficient regional consensus. Utilities have important "filing rights" and roles under Transmission Owner Agreements that tend to require their support for regional transmission plans.

PROVIDES A PATHWAY TO COST ALLOCATION AND RECOVERY

Outside of RTOs where there is no regional tariff through which costs can be recovered, obtaining State PUC approval of cost recovery is critical. Only the designated IOUs in those service territories are empowered to make the application to the state for such cost recovery from the retail customers there. Therefore, active participation and collaboration from those utilities is essential to recover the costs of transmission. Otherwise, no investment would occur, or projects may lack adequate scope. With respect to the Acadiana project, Brattle explained, "[c]ost allocation via transmission ownership (not financial transfers) was easier to accomplish. Especially for non-market regions and utilities, financial transfers may not even be possible or prove difficult to implement. For the ALP Project, each entity shared costs by building, owning, and maintaining a different segment of the buildout."[148] Thus, collaboration in the form of joint ownership can be an essential means of addressing a key to transmission investment which is cost allocation and recovery.

147 MISO staff, interview with the authors, November 6, 2023.

148 "Roadmap to Improved Interregional Transmission Planning" at 37.

8 BARRIERS TO COLLABORATION TODAY

Without requirements for formal collaboration through RTOs or otherwise, and with the lack of collaboration that happens even within RTO areas, it is important for policymakers to remove barriers to collaboration and find ways to encourage it. This section draws lessons from experiences over the last couple decades about barriers to collaboration that currently exist.

EXPLICIT RULES AGAINST COLLABORATION

In some cases, the entities with the most information about the transmission network and its needs are explicitly prevented from sharing information about grid needs and options, restrictions that are largely borne from the competitive transmission reforms of Order No. 1000. Sometimes the protocols around competitive procurement prevent such collaboration. According to one transmission owner in New England, "ISO-NE was unable to reveal the specific substation and contingency that gave rise to these significant adverse impacts to the affected TO, again because it had not yet been proven that the solution to the potential problem would not follow the competitive RFP process."[149] Quinlan also testified, "ISO-NE is no longer able to discuss the details of Needs Assessments with individually affected TOs, as this approach is perceived as giving the participating TOs a potential competitive advantage in any subsequent RFP."[150] Quinlan also stated, "the competitive RFP process does not accommodate iterative refinements as solutions are evaluated. This prevents TOs, who are in the best position to assess how to maximize the use of existing facilities and rights-of-way, from obtaining stakeholder input and co-optimizing proposed solutions to address multiple needs. Co-optimization can only be performed effectively with an open and collaborative planning process."[151] These examples illustrate the limits on information flow that exist, and the fact that both parties know more useful and relevant information than they are allowed to share. These limits can reduce the quality of both parties' analysis because they are based on incomplete information. Current ISO-NE planning staff said in an interview with this report's authors that the limitations on information sharing makes transmission planning more difficult.

Similar dynamics preventing information sharing exist in the PJM region, again largely to facilitate the competitive transmission processes that were implemented following Order No. 1000. According to one transmission owner, "[t]here is no open, collaborative process any longer to share drivers and ideas in a manner that is flexible and responsive to changing on-

149 *See* Affidavit of William J. Quinlan, President of Transmission and Offshore Wind Project at Eversource Energy, pg. 5 (Aug. 11, 2022) attached as Exhibit 2 to Comments of Developer Advocating Transmission Advancements, FERC Docket No. RM21-17 (August 22, 2022), https://elibrary.ferc.gov/eLibrary/filedownload?fileid=dcc9c45e-60ee-ce89-8e0f-82ac9b400001.

150 *Id.* at 3.

151 *Id.* at 4.

the-ground circumstances."[152] Weaver also stated, "[r]ather than being able to discuss needs and dynamic factors that may inform their evolution, competitive window participants are left guessing what actual problems and kinds of solutions PJM seeks in the proposal window."[153] And, "PJM does not receive solutions that consider all the important fundamental factors impacting the drivers for transmission buildout. Rather, it considers and awards proposals that are targeted to address needs in a manner that is neither dynamic nor flexible, as the natural outcome of imposed competition is that it creates disincentive to share information about how a driver impacts potential transmission system needs."[154]

Similar restrictions occur in SPP. "In the case of SPP, when a project is expected to be deemed a competitive project, the information and data flow between the incumbent utility and SPP almost stops."[155]

Parties at both utilities and the RTO stated to this report's authors that there was much more collaboration between the various owners of the network and between owners and RTO planners prior to 2011 when FERC issued Order No. 1000.

Antitrust policies can strictly bar certain communications and collaboration. Communications between competitors in competitive markets are illegal in order to prevent collusion or other activities that can raise prices. In the transmission space, which is generally a regulated industry, the application of standard antitrust rules on collaboration are vague at best, but conservative entities may wish to avoid any antitrust legal risk by erring on the side of reducing communication. For example, it is standard practice today for electric industry trade associations to have antitrust policies that include such communication-restricting guidelines as:

> "DO NOT, without prior review by counsel, have discussions with member companies about the following: company prices, fees or rates, or features that can impact prices; uniform terms of sale, warranties, or contract provisions; allocating markets, customers, territories products or assets with your competitors; whether or not to deal with any other company; any competitively sensitive information; or any competitive employment information including wages, salaries, or benefits; terms of employment; or even job opportunities."[156]

The sharing of "competitively sensitive information" is particularly noteworthy because the needs and impacts of transmission investment options are some of the items that have been shared throughout the many examples of successful transmission development we reviewed. Restricting such information sharing could be a hindrance to transmission development.

The administrative process can also hamper effective collaboration. One PJM planning process participant noted that rather than collaborating to identify least cost solutions to identified needs, "[c]onsiderable administrative time and effort is spent on presenting as many proposals

152 *See* Affidavit of David W. Weaver, P.E., Vice President of Transmission Strategy at Exelon Corporation, pg. 3 (Aug. 16, 2022) attached as Exhibit 2 to Comments of Developer Advocating Transmission Advancements, FERC Docket No. RM21-17 (August 22, 2022) ("Weaver Affidavit"), https://elibrary.ferc.gov/eLibrary/filedownload?fileid=dcc9c45e-60ee-ce89-8e0f-82ac9b400001.

153 *Id.* at 4.

154 *Id.* at 5.

155 Cooley Affidavit at 7.

156 Edison Electric Institute's Anti-trust policy at https://www.eei.org/-/media/Project/EEI/Documents/Resources-and-Media/EEI-Antitrust-Compliance-Guidelines.pdf?la=en&hash=BA3CEAC1352B158F0499479AD5822E2B2531D828.

to PJM as possible rather than a focusing on the larger picture and collaboratively developing solutions that are likely constructable. Money and time are wasted forwarding proposals that PJM has no intention of considering."[157]

DISINCENTIVE TO SHARE INFORMATION

Even if information sharing is allowed, often there is a disincentive to share under certain prevailing rule in transmission planning processes. According to one transmission owner, "[t]he transmission entity's local knowledge related to the route and projected costs is competitively valuable and therefore the incumbent is disincentivized to share that knowledge with the regional planner and stakeholders."[158] This dynamic was raised by many of the interviewees for this report and highlights an added complexity to an already complex process surrounding the ability to successfully site necessary transmission.

Some RTO and regional planning entities have a disincentive to share information as well. "The SPP regional planners actively discourage communications with the incumbent utility to avoid even the perception that the incumbent is being given a competitive advantage in the competitive planning process."[159] They report not wanting to be seen as favoring any entity, so even having conversations with people who possess valuable information can be seen as unduly tilting the competitive playing field. ISO-New England stated in its Order No. 1000 compliance filing that the new rules would prevent data sharing and undermine the "advantageous, open interaction that has produced exemplary results in New England."[160]

Potential collaborators and developers outside of RTO areas may be dissuaded from working together or proceeding with development plans if their plans can be co-opted later. According to the organizers of the Power from the Prairie project which aims to build a large set of transmission projects crossing the Eastern and Western Interconnection seam, their participants, utility and other collaborators, fear they will do significant study and development work that is then taken from them and offered to third parties.[161] This possibility reportedly dissuades potential collaborators.

These disincentives to collaborate will be important for policymakers to consider going forward. It is likely not the case that rules directing collaboration would be effective at overcoming institutional and regulatory disincentives.

RIGID DEFINITIONS OF NEEDS AND BENEFITS

A barrier to collaboration can exist when certain "needs" can be discussed, and others cannot. It is well-documented[162] that transmission typically serves multiple purposes, and it is difficult

157 Weaver Affidavit at 6.

158 Cooley Affidavit at 7.

159 *Id.*

160 Filing Letter of ISO New England Inc., FERC Docket No. ER13-193-000, at p. 24 (Oct. 25, 2012) ("ISO-NE Filing Letter"), https://elibrary.ferc.gov/eLibrary/filedownload?fileid=01a70a75-66e2-5005-8110-c31fafc91712.

161 Personal communication with Bob Schulte, Managing Member, Power from the Prairie, July 2023.

162 "Transmission Planning for the 21st Century," at 30-58.

to define one "need" independently from other needs or uses. In the case when NERC reliability criteria violations are identified in a power flow or stability model, that narrow need can be the basis for action. But, more commonly, any given expected system condition can be addressed by multiple possible solutions and any given investment can address multiple needs or purposes. In this situation, the transmission network is very different from a typical commodity traded in competitive markets where the products are frequently characterized by high levels of homogeneity. There are many more options and combinations of needs and investment options that require analysis and consideration. When regional planners and various entities such as owners of parts of the transmission network can only communicate about certain needs and not others, the scope of that communication can be severely limited. There is also an issue of timing, where solutions for only the single RTO-identified need is addressed at a time, when more needs could be addressed at the same time. The result is inferior plans and excessive focus on narrow needs where other benefits of different investment options are ignored leading to foregone consumer benefits. If and when FERC changes transmission planning requirements to focus more on multi-benefit planning as proposed in its Notice of Proposed Rulemaking (RM21-17), this barrier to coordination could be exacerbated.

CONFLICTING DUAL ROLES OF RTOS

Another barrier to collaboration is when the RTO is put in the dual position as a planner and regulator. RTOs as originally designed included prominently a role as a transmission planner as described in Section IV above. When an RTO is given a quasi-regulatory role to choose between participants and make binding policy decisions, they take on restrictions similar to regulatory agencies about communications. Economist Paul Joskow noted this awkward role for ISOs and RTOs: "ISO's are not economic regulators in the traditional sense and have neither the expertise nor authority to adopt transmission ratemaking procedures"[163] and "it is quite clear that the ISOs do not want to become, and are not supposed to be, economic regulators in this sense and this is not where their experience lies."[164] This is different from dispatching generators because that is done on the basis of simple clear criteria such as bid price for a MWh.

Electric industry stakeholders are generally familiar with "ex parte" rules at FERC and state regulatory commissions where contested pending proceedings cannot be discussed outside of public meetings. Similar rules at RTOs restrict communications significantly. When communications restrictions are placed on the RTO which is also supposed to be performing transmission planning of an integrated network owned by multiple different entities, the information they have to work with is reduced. For example, ISO-NE noted in their Order No. 1000 compliance filing that competition prevents data sharing and that the competitive process, where entities compete for individual solutions, eliminates the benefits of open collaboration.[165] PJM in its NOPR comments also added that "the level of transparency required under Order No. 1000 planning processes has made it more challenging to work through issues that must be maintained as confidential (e.g., identification and selection of projects needed

163 Paul Joskow, "Competition for Electric Transmission Projects in the U.S.: FERC Order 1000," MIT Center for Energy and Environmental Policy Research, March 2019, at 22, https://ceepr.mit.edu/wp-content/uploads/2021/09/2019-004.pdf.

164 *Id.* at 51-52.

165 ISO-NE Filing Letter at 24.

to address CIP-014 needs), resulting in additional processes to allow PJM to plan for such needs."[166] Notably, it is different in the United Kingdom and Texas where competitive solicitation is performed by the regulator itself, not delegated to the grid planning entity.

MISAPPLICATION OF COMPETITIVE PRINCIPLES

The attempt to adopt competition in transmission is still an experiment. The national representative of industrial consumers has observed, "[c]ompetitive processes, though well intentioned, have led to less cooperation and coordination within regions."[167]

Relying on competition in a network monopoly industry has little foundation in economic theory and is very rare in practice, and was not part of EPAct 1992 or 2005, or FERC's efforts in the 1990s or 2000-2010 reforms aimed at generation competition.

In competitive markets such as the generation sector, public policy seeks to preserve independent action by separate competitors. Collaboration is barred. The theory in competitive markets is that competition between independent entities will produce discipline and innovation that will lead to lower prices for consumers. Economic theory and consensus within the economics profession supports this approach, when the conditions for robust competition are present. Generally, there are five conditions that must hold for a market to be considered competitive: 1) the market is comprised of many buyers and sellers where all are price takers and lack the market power to influence prices; 2) the firms in the market produce the same product; 3) there is transparent information about prices and products; 4) transaction costs are low; 5) buyers and sellers can freely enter and exit the market.[168] Arguably, these conditions are all present in the generation sector. But in transmission, there are not many buyers or sellers, only a single commodity that is exchanged, high transaction costs, and minimal free entry or exit, nor could there be any of these characteristics with current technologies. FERC never really attempted to establish a true "competitive market" in transmission, but rather what is known as "competition for the market,"[169] involving competitive procurement of a monopoly facility. Still, competition policy on information sharing and collaboration can be applied by policymakers, whether helpful or harmful.

The competitive conditions above generally apply to the generation sector. The efficient scale of generation is such that there can be hundreds of independent entities competing to provide electric energy in a given region. FERC's Order No. 888 in the mid-1990s established this finding. "Scale economies encouraged power generation by large vertically integrated utility companies that also transmitted and distributed power. Beginning in the 1970s, however,

166 Initial Comments of PJM Interconnection LLC, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection FERC Docket No. RM21-17-000, August 17, 2022, at 47, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=d08217aa-3814-cbcd-9df7-82ad90b00000.

167 Comments of the Electricity Consumers Resource Council (ELCON), Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection ANOPR FERC Docket No. RM21-17-000, July 15, 2021, at 5, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=96340958-e66d-c956-922b-7c7972b00000.

168 Jeffrey M. Perloff, Microeconomics Theory and Applications with Calculus, Fourth Edition, Chapter 8 Competitive Firms and Markets and Chapter 11 Monopoly and Monopsony.

169 *See* Paul Joskow, "Competition for Electric Transmission Projects in the U.S.: FERC Order 1000," MIT Center for Energy and Environmental Policy Research, March 2019, at 22, https://ceepr.mit.edu/wp-content/uploads/2021/09/2019-004.pdf; *see also* Affidavit of Dr. Carl R. Peterson, Executive Advisor to Concentric Energy Advisors, Inc. (Sep. 19, 2022) attached as Attachment A to Reply Comments of Developer Advocating Transmission Advancements, FERC Docket No. RM21-17 (September 19, 2022), https://elibrary.ferc.gov/eLibrary/filedownload?fileid=d7b35f46-cf91-cbff-829a-83577e000001.

additional economies of scale in generation were no longer being achieved,"[170] Now, after nearly 30 years, competition in generation has taken hold in most of the country, though it is a policy choice for states to make and many have opted to keep generation in a utility monopoly rate base.

The transmission sector is also not structurally competitive like generation, nor is there any evidence to suggest it might be. There are significant economies of scale such that it only makes sense to have one entity own the integrated network in a given area. Unlike generation where Markets for Power by Paul Joskow and Richard Schmalensee initially articulated the structural competitiveness, followed by many other economic studies, there are no similar studies of the transmission sector demonstrating structural competitiveness.[171]

FERC and the courts have treated generation and transmission very differently. For example, in FERC's Merger Policy Statement, extensive analysis was devoted to generation competition, stating "we believe that the public interest requires policies that do not impede the development of vibrant, fully competitive generation markets. We are refining our analysis of the effects of proposed mergers on competition in order to protect the public interest in the development of such highly competitive markets."[172] Yet the loss of competition in transmission was not even mentioned as a potential harm when neighboring utilities merged. FERC's discussion of transmission focused on ensuring any horizontal mergers provided open access to their system in order to "encourage wholesale competition."[173] The Commission was focused on the fact that, "[l]imitations on available transmission capability that prevent competitors from participating in a market can give substantial market power to incumbents in the market. Conditioning merger approval on eliminating a known constraint could help to mitigate this type of market power. Where constraints on other systems are a problem, the applicants would also be required to seek transmission expansion on those systems."[174] Thus, transmission was treated as a regulated monopoly sector and more of a common carrier as a platform for generation competition. FERC along with the Supreme Court has recognized the distinction between "those areas of the industry amendable to competition, such as the segment that generates electric power" and "the segment of the industry characterized by natural monopoly—namely, the transmission grid that conveys the generated electricity."[175]

170 Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Pub. Utils.; Recovery of Stranded Costs by Publ. Utils. & Transmitting Utils., Order No. 888, 61 FR 21540 (May 10, 1996), at 18.

171 Paul L. Joskow & Richard Schmalensee, 1988. "Markets for Power: An Analysis of Electrical Utility Deregulation," MIT Press Books, The MIT Press, edition 1, volume 1, number 0262600188.

172 Order No. 592, Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, 77 FERC 61,263, at 15 (1996), https://www.ferc.gov/sites/default/files/2020-04/rm96-6_0.pdf

173 *Id.* at 16.

174 *Id.* at 84.

175 *Morgan Stanley Cap. Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cnty.*, 554 U.S. 527, 536 (2008), https://supreme.justia.com/cases/federal/us/554/527/#tab-opinion-1962706; *see also* New York v. FERC, 535 U. S. 1, 9-10 (2002); Public Util. Dist. No. 1 of Snohomish Cty. v. FERC, 272 F. 3d 607, 610 (D.C. Cir. 2001).

9 INSTITUTIONAL FORMS OF COLLABORATION AND HORIZONTAL INTEGRATION

Collaboration can work in a variety of market structures. It can work in areas with RTOs, where the RTO, utilities (investor-owned, public, and consumer-owned), and other stakeholders collaborate in RTO processes or with each other separately. It can work outside RTOs with various utilities and developers. It can work with independent transmission developers working with utilities. And there are probably more possibilities.

Collaboration can take place through joint ownership, coordinated planning, and various other contractual or organizational arrangements. There is a recent trend of independent developers coordinating with utilities, where the developer does more of the siting, permitting, analysis, community relations, and landowner lease agreements, while the utility partners on some of those functions and takes over ownership when the line is complete.

Diversity in how roles and responsibilities are allocated around the country is likely to remain. Efforts to mandate RTO participation have failed, leaving utilities with significant discretion in how they operate and partner with others. There are a variety of institutional arrangements around the country and that is not likely to change, at least not quickly or in the near term. Some utilities want to own and develop transmission, others have different interests and incentives. Consumer-owned, investor-owned, and publicly owned utilities all have different incentives and motivations, and there is diversity within each category as well.

In areas with no or little existing transmission, such as offshore networks and interregional lines, there is likely to be a greater role for independent developers and transmission competition. In those cases, there is less interaction with the existing network and rights of way. States and utilities can potentially competitively procure transmission networks and lines where no network exists, as New Jersey has done recently. If they do, independent developers will need to follow competitive protocols that may limit collaboration and bar collusion. The benefits of collaboration with existing utilities will likely be lower in those cases and the necessity or extent of utilities partnering will be lower.

VARYING FORMS OF COLLABORATION

There has been a wide variety of organizational forms of collaboration. Some were IOU to IOU, others involved munis and coops, and others involved actual horizontal consolidation through merger, such as PacifiCorp, ATC, and VELCO. The AC and DC ties between California and the Pacific Northwest were a collaboration between public entities and utilities. For jointly developed projects they can take a couple different forms.

Some involved independent developers. For example, the Western Spirit transmission line was initially privately developed by Pattern Energy was then taken over by Public Service Company of New Mexico, who now owns the line.[176]

Joint asset ownership agreements were used in some cases. Georgia's Integrated Transmission System is an example of utilities investing in joint asset ownership in order to expand the transmission system and improve efficiency and reliability.

The point is that collaboration is important but that it can take many forms, and likely will in the extremely diverse US electric industry structure.

176 PNM Staff, interview with the authors, October 18, 2023.

10 | CONCLUSION

From this review of 29 successful examples of transmission development over multiple decades and all regions of the US, we find collaboration to be a critical element. This review reveals various forms of collaboration mostly involving information sharing between the various entities involved in analyzing, planning, developing, financing, owning, and operating parts of integrated regional transmission networks.

We find collaboration provides multiple benefits such as the ability to addresses multiple needs, better quality and quantity of information for network planners, better use of existing assets and rights of way, more efficient suite of technologies, faster development of needed infrastructure, improved coordination of outages during and after construction, more likely to result in needed consensus, provides a pathway to cost allocation and recovery.

This finding is not entirely surprising given the long history of legislative and regulatory encouragement of collaboration over the industry's history.

Our analysis of transmission and generation structures and policies finds transmission collaboration is entirely compatible with and supportive of competition in structurally competitive sectors. However, there is limited evidence to support the proposition that transmission development itself is or should be considered structurally competitive.

We find that significant barriers exist today to effective transmission collaboration, including disincentives to collaboration introduced through Order No. 1000. Regulatory requirements for coordinated regional planning as an RTO function or for interregional transmission planning have facilitated the introduction of planning processes, including periodic studies, stakeholder meetings and published reports. But, as described above, those processes deliver suboptimal results when incentives for active engagement and open information exchange are lacking. In contrast, the previously cited examples of successful transmission planning collaboration demonstrate that when incentives of the planners, owners and users of the system are aligned, substantial transmission investment and accompanying benefits can be realized.

Given the importance of transmission collaboration, policymakers should take care to foster, rather than discourage or prevent, effective collaboration in transmission development.

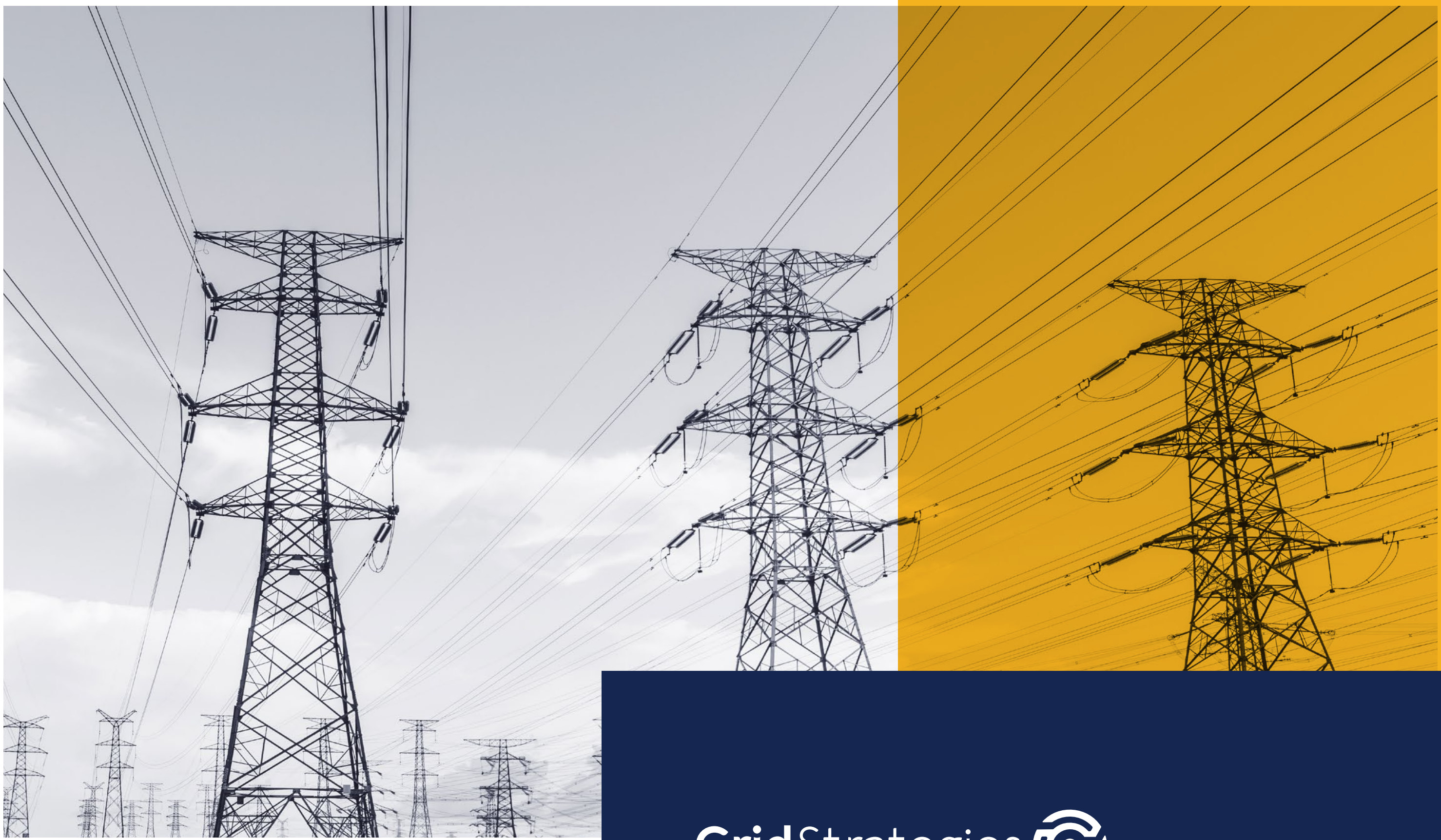
APPENDIX A
INTERVIEWEES

- **Adam Alvareze, Laurie Williams, Todd Fridley, and Tom Duane**, Public Service Company of New Mexico
- **Andy Kowalcyk**, Southern Renewable Energy Alliance
- **Beth Soholt**, Clean Grid Alliance
- **Bob Ethier**, ISO-NE
- **Carrie Zalewski**, American Clean Power Association
- **Chuck Marshall and Devin McMackin**, ITC Holdings
- **Dave Weaver**, Exelon Corporation
- **Eric Blank**, Colorado Public Utilities Commission
- **Foung Mua**, Sacramento Municipal Utility District
- **Francis Pullaro**, RENEW Northeast
- **Jared Ellsworth**, Idaho Power
- **Jennifer Curran**, MISO
- **Jens Nedrud**, Puget Sound Energy
- **Jodi Moskowitz and Jason Kalwa**, Public Service Enterprise Group
- **John Waterhouse and Jeff Dodd,** Ameren Corporation
- **Ken Seiler**, PJM
- **Kris Zadlo**, Grid United
- **Michelle Manary**, Bonneville Power Administration
- **Priti Patel**, Great River Energy
- **Pulin Shah**, Exelon Corporation
- **Ray Gifford and Matt Larson**, WBK Law
- **Shaun Foster and Larry Bekkedahl**, Portland General Electric
- **Spencer Gray**, Northwestern and Intermountain Power Producers Coalition
- **Stuart Nachmias**, Con Edison

APPENDIX B
ACRONYMS

AC Alternating Current
APPA American Public Power Association
APS Arizona Public Service Company
ATC American Transmission Company
BPA Bonneville Power Association
CAISO California Independent System Operator
CAWG Cost Allocation Working Group
CEC California Energy Commission
COTP California-Oregon Transmission Project
CREZ Competitive Renewable Energy Zones
DC Direct Current
DEC Duke Energy Carolinas
DEP Duke Energy Progress
DOE U.S. Department of Energy
ERCOT Electric Reliability Council of Texas
EWG Exempt Wholesale Generator
FERC Federal Energy Regulatory Commission
FPA Federal Power Act
FPC Federal Power Commission
GETs Grid Enhancing Technologies
GI Generator Interconnection
GRE Great River Energy
GW Gigawatt
HVAC High-Voltage Alternating Current
HVDC High-Voltage Direct Current
IMPA Indiana Municipal Power Agency
IRP Integrated Resource Planning
ITS Integrated Transmission System
IOU Investor-Owned Utility
ISO Independent System Operator
ISO-NE Independent System Operator of New England
JTS Joint Transmission System
kV Kilovolt
LADWP Los Angeles Department of Water and Power
LRTP Long Range Transmission Power
LSE Load Serving Entity
MISO Midcontinent Independent System Operator
MOD Modeling, Data, and Analysis NERC Standards
MPC Montana Power Company
MRES Missouri River Energy Services
MVPs Multi-Value Projects
MW Megawatt
MWh Megawatt hour
NCTCP North Carolina Transmission Planning Collaborative
NERC North American Electric Reliability Corporation
NGRID National Grid USA
NIMBY Not in My Backyard
NOPR Notice of Proposed Rulemaking
NU Northeast Utilities
NSTAR Eversource
OATT Open Access Transmission Tariff
PG&E Pacific Gas and Electric
PNM Public Service Company of New Mexico
PPL Pennsylvania Power and Light
PSE Puget Sound Energy
PSEG Public Service Enterprise Group
PSI Public Service Company of Indiana
PTO Participating Transmission Owner
PUC Public Utility Commission
PURPA Public Utility Regulatory Policies Act
PSC Public Service Commission
RETA Renewable Energy Transmission Authority
RFP Request for Proposals
RGOS Regional Generator Outlet Study
ROFR Right of First Refusal
ROW Right-of-Way
RPG Regional Planning Group
RPS Renewable Portfolio Standard

RTG	Region Transmission Group
RTO	Regional Transmission Organization
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SMD	Standard Market Design
SMUD	Sacramento Municipal Utility District
SNETR	Southern New England Transmission Reliability
SPP	Southwest Power Pool
SPPT	Synergistic Planning Project Team
SRP	Salt River Project
STARS	State Transmission Assessment and Reliability Study
TAG	Transmission Advisory Group
TANC	Transmission Agency of Northern California
TAPS	Transmission Access Policy Study
TO	Transmission Owner
USBR	U.S. Bureau of Reclamation
VELCO	Vermont Electric Power Company
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WPPI	Wisconsin Public Power Inc.
WVPA	Wabash Valley Power Association



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Grid Strategies LLC is a power sector consulting firm helping clients understand the opportunities and barriers to integrating clean energy into the electric grid. Drawing on extensive experience in transmission and wholesale markets, Grid Strategies analyzes and helps advance grid integration solutions.

Based in the Washington DC area, the firm is actively engaged with the Federal Energy Regulatory Commission, Department of Energy, state Public Utility Commissions, Regional Transmission Organizations, the North American Electric Reliability Corporation, Congressional committees, the administration, and various stakeholders.