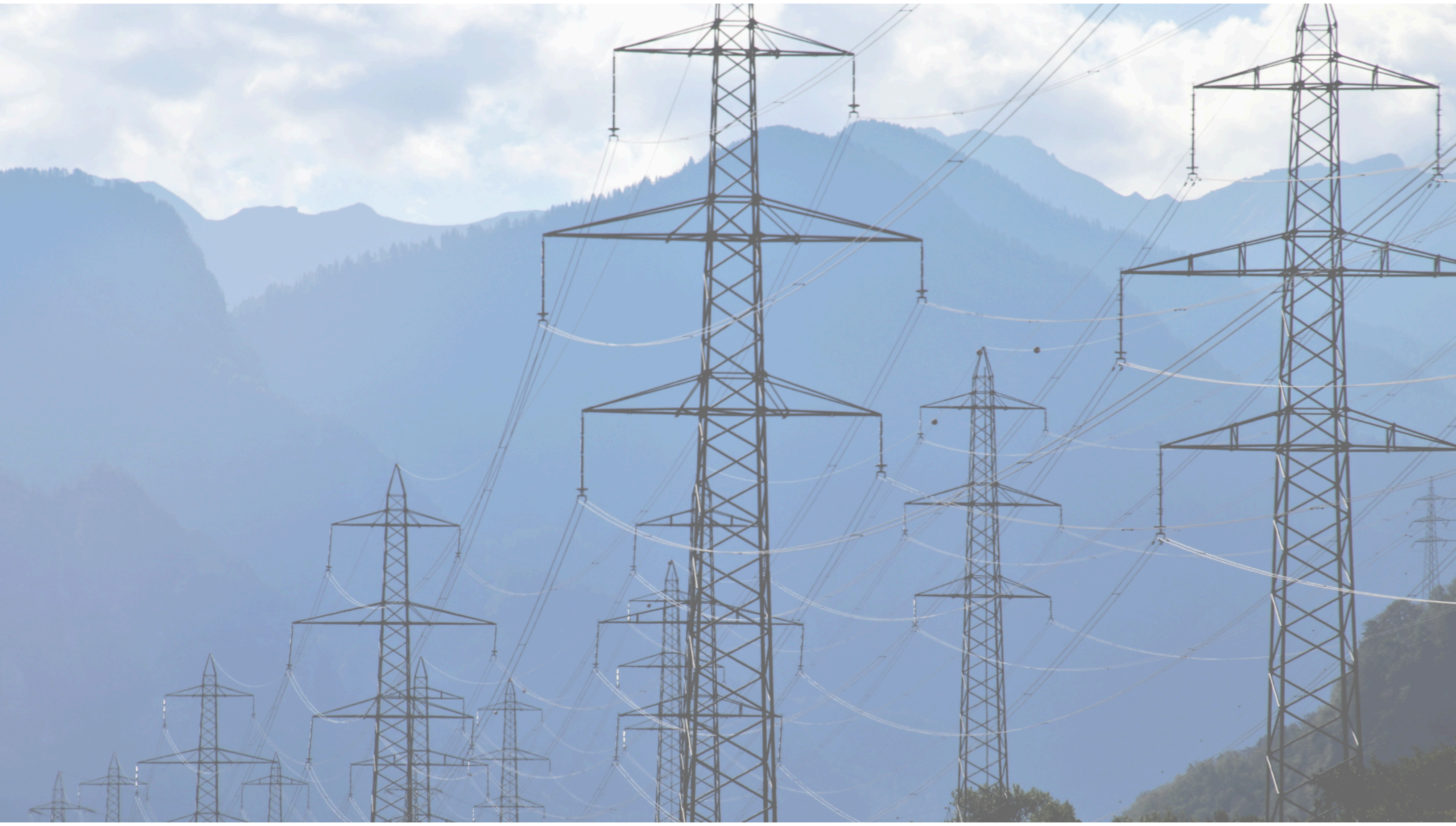

Aspen Transmission Forum

Post-Forum Report

Emily Fisher, Anna Foglesong & Rob Gramlich, Co-Chairs
Cina Vazir, Rapporteur

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For all inquiries, please contact:
Energy & Environment Program
The Aspen Institute
2300 N Street, NW | Suite 700
Washington, DC 20037
Phone: 202.736.2933

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Introduction

Rising demand for electricity in the United States is a pressing national, state, and local challenge. Annual load growth nationally has averaged below 1% since the beginning of the 2000s.[1] Over the next five years, load growth is projected to increase to an annual average of nearly 3%, a rate not seen since the 1980s.[2] The United States must build significantly more generation, transmission, and distribution of electricity to meet this new increase in demand.

Transmission is a key part of the challenge. Transmission infrastructure plays the important function of transporting electricity from where it is generated to where it is consumed. An efficient transmission system provides greater reliability and resilience to the electric grid while reducing costs for the average consumer. Despite these benefits, the United States only built 55 miles of new high-voltage transmission lines in 2024 and 125 miles in the first half of 2025.[3] That number pales in comparison to the estimated need for 64% growth in regional transmission and 114% growth in interregional transfer capacity from 2020-2035 under median modeling scenarios.[4]

The U.S. transmission system will need to expand much faster to meet demand for electricity. A failure to build sufficient transmission could result in massive costs. Citizens across the country would likely face more expensive and less reliable access to electricity. U.S. businesses and the wider economy would struggle for the same reason. And American national security would be threatened by less economic competitiveness in key industries—like artificial intelligence and semiconductors—and a less resilient electric grid.

The Aspen Institute's Energy and Environment Program convened a group of leaders from across the power sector in Aspen, Colorado for three days in February, 2025 to discuss the urgent challenges and solutions for building more transmission infrastructure in the United States. This report summarizes the key takeaways from the convening along the lines of "who, what, where, when, why, and how." A significant portion of the report focuses on the "how" in particular, with themes organized along the "Three P's" of planning, permitting, and paying for transmission. The findings below reflect the essence of the conversation but should not be mistaken to represent the views of any single participant nor their employer.

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[1] https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf

[2] https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf

[3] https://www.statista.com/statistics/551519/us-line-length-of-electricity-transmission-projects-completed/#:~:text=In%202024%2C%20over%20350%20miles,the%20length%20completed%20that%20year.

[4] https://www.energy.gov/sites/default/files/2023-12/43451_DOE_GDO_Needs_Study_Fact_Sheets_United_States_v6_RELEASE_508_Compliant.pdf

Why: Focusing on the benefits of cost, reliability, and resilience

The U.S. transmission system needs to expand to meet rising domestic demand for electricity. Electrification, the onshoring of manufacturing, and construction of data centers for artificial intelligence (AI) are all leading to a new era of projected load growth.[5] U.S. demand for electricity was nearly flat for the last two decades. Now, some predict load growth could increase by around 3% annually over the next five years.[6] More regional and interregional transmission is required to keep pace with this new growth in electricity demand.

Participants in Aspen noted that the current messaging and communications for building more transmission are largely ineffective. Generation sources and demand drivers for electricity have been highly politicized in recent years. This politicization creates challenges for communicating the value of transmission. Several participants noted that, while transmission is crucial for the energy transition, there are also many other drivers of transmission expansion that may have broader and more durable bipartisan support across changes in political cycles.

A more successful approach would focus on bipartisan objectives, such as how transmission reduces costs and improves reliability for American homes and businesses including AI-driven data centers which are critical for national security. Participants discussed the potential for long-distance transmission to lower the cost of U.S. generation and prices for U.S. consumers by creating a more integrated grid.[7] These benefits are important to quantify and communicate since cost-saving is a bipartisan message that resonates with everyday Americans.

Participants also discussed the need to communicate the benefits of reliability. Transmission can significantly improve grid reliability, which could be strained over the coming decade even with conservative assumptions around demand growth and the challenges of building and connecting new generation. One participant outlined the effects of reliability on businesses, noting how several hours of power outages can cause supermarkets to discard their refrigerated items, grid instability forces automakers to shutter their production lines, and a blip of even seconds of power can make semiconductor manufacturers lose hundreds of millions in revenue.

Reliability also has huge effects on citizens. This has come into sharp relief recently with blackouts in places like Texas and Spain. Participants remarked that more work can be done to quantify the benefits of reliability and to integrate that into transmission planning.

Many of the economic impacts of transmission spill into national defense. Reliable and affordable power is needed to support the defense industrial base and onshore production of critical defense technologies. The economic competitiveness of emerging technologies like AI similarly depend on a strong transmission system. For instance, China is rapidly investing in its

[5] https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf
[6] https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf
[7] https://media.rff.org/documents/WP_25-10_kFRJaAE.pdf

own power system to enable a highly efficient AI industry. Transmission can impact the outcome of the global AI race and thereby heavily affect U.S. national security.

Grid resilience has a comparable impact on national security. A robust transmission system enhances grid resilience by enabling electricity transfer within and across regions. As one participant stated, this “helps ensure that a bad day does not become a catastrophic day” in the case of disruption from weather events or attacks by adversaries. These national security benefits drive the need for transmission and can be an effective bipartisan message at the national level.

Transmission’s impact on jobs may be a more compelling framing at the local and state levels. Building transmission lines can create direct jobs and facilitate many more indirect jobs by supporting economic activity. These workforce benefits cannot be overstated for the local and state actors who often play a key role in deciding whether more transmission gets built.

Nonetheless, participants in Aspen stressed that many entities in the power sector are still nascent in their efforts to quantify the benefits of transmission. According to several participants, more work needs to be done to decide on modeling practices and to integrate benefit quantification into decision making. It may be particularly helpful to have more industry standards to define and calculate the benefits of resilience and reliability. Better quantification can improve decision making and build alignment around the dual framing of economic and national security benefits, which resonate at the local, state, regional, and national level.

Efforts to communicate the benefits of transmission will likely continue to confront various hurdles. As discussed, one key challenge is avoiding the politicization of transmission. A second challenge is the difficulty of aggregating the benefits of transmission. Benefits often fall at different county, state, regional, and national levels. And many of these benefits are diffuse, while the cost of building new transmission lines is real and immediate. Transmission faces the quintessential challenge of a common good: individual actors try to minimize the cost they pay for shared benefits. Overcoming these barriers requires communications that are bipartisan, quantifiable, and simple.

Where and When: Building longer and quicker

Most discussants in Aspen were generally aligned around the “where” and “when” of the transmission challenge in the United States.

Many parts of the United States have shifted spending in the last decade toward local transmission projects rather than regional and interregional lines. This has partly been a response to lower regulatory hurdles and earnings incentives to build local projects. In PJM, for example, local transmission spending increased from 9% of total investment in new transmission from 2005-2013 to 73% from 2015-2021.[8] One participant described how the U.S. power sector is

[8] https://rmi.org/increased-spending-on-transmission-in-pjm-is-it-the-right-type-of-line/

good at building distribution and low-voltage transmission and is getting better at building regional transmission. However, the U.S. power sector falls short on constructing long-distance, high-voltage lines.

Most participants agreed that the United States needs to more quickly build regional, and particularly interregional, transmission lines. A participant argued that there is a special need for East-West transfers and for getting wind from the middle of the U.S. to eastern and western load centers. Large-scale transmission projects are among the most cost-effective ways to address load growth, and there are signals that investment in these projects is beginning to increase.[9] Yet participants were quick to highlight that different regions will have different needs for interregional transfer.[10] One participant also argued for more geographic diversification of transmission infrastructure to improve resilience and reduce risk.

Transmission projects can take over a decade to move from planning to operation.[11] Investment in transmission infrastructure needs to happen now for the United States to meet projected load growth over the next decade. Multiple participants were wary of the uncertainty in load growth and how that casts risk on transmission investments, although other participants ventured that it may be better to overbuild transmission than to build too little. More generally, most participants agreed that load is now growing compared to the last few decades.

What: A larger and more innovative transmission system built through a blend of centralized and decentralized planning

What is a vision for the future grid of the United States? This was a central question for participants in Aspen. At its core, transmission has two primary purposes: connecting low-cost resources to the grid and providing geographic diversity to improve reliability and resilience. Distributed resources can lessen the need for transmission at moderate levels but are expensive at scale since they require overbuilding and losses in efficiency. Similarly, energy storage is important but cannot yet provide the required level of resilience and resource adequacy. A low-cost, reliable, and resilient grid in the United States requires more transmission.

Yet there are still questions surrounding what the transmission system of the future will look like. Various participants noted that most transmission planning in the United States is highly decentralized. Decentralization poses a challenge since many of the investments required for high-voltage, long-distance lines require billions of dollars. Investments at this scale are limited

[9] https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf
[10] https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/ITCS_Filing_Fall2024_signed.pdf
[11] https://www.iea.org/data-and-statistics/charts/average-lead-times-to-build-new-electricity-grid-assets-in-europe-and-the-united-states-2010-2021

due to large uncertainty on various fronts, which could be mitigated if the federal government were to play a larger role in setting a national vision for the transmission system.

Some participants discussed the potential for a coast-to-coast network—akin to the interstate highway system—managed by the federal government. The entity articulating the vision for such a system could be the same one in charge of executing it, although no federal entity is currently set up to play such a role. Participants in favor of more central planning stated their view that incrementalism and current systems will not lead to the necessary and timely expansion of transmission infrastructure. Theoretically, a top-down approach could be quicker and cheaper. Several participants supported a process with more top-down planning complemented by flexibility at the solutions level.

Other participants were wary of a centralized process to build the nation's transmission system. The current transmission ecosystem in the United States is very much a bottom-up and utility-by-utility structure. Because of this, some participants speculated that U.S. transmission is likely going to be like American cities—sprawling roads connected by interstates, with a mix of both local and central planning. This contrasts with other economies like China which use more central planning in their infrastructure system.

There may not be any single end-state for large-scale transmission in the United States. The current U.S. system has been built from the ground up and it may not be realistic to have a system that is entirely centrally planned in the future. One participant predicted that the U.S. grid will look like "a lot of squiggly lines." Existing rights of way for transmission are extremely important, and it will be hard to build greenfield projects even though they can often be more efficient.

Participants arguing that the future of the grid will remain decentralized pointed to the political difficulties of centralization. Many states and localities may be opposed to a central planner. Tensions around centralization have existed throughout the history of the United States and will not disappear anytime soon. A pragmatic view of the future may be one of bottom-up transmission expansion supported by episodic federal interventions. In that case, it will be important to properly design and plan those interventions to maximize their impact. One participant even argued that further democratizing the grid, not central planning, is how the United States can best make progress on transmission in the near term.

Participants were far more aligned on the potential for innovation to create a stronger transmission system. Improved models, supported by advances in AI, can help solve important engineering and design questions. A participant noted that there is huge potential for more construction innovation to lower the cost per line and cost of undergrounding. Innovation has drastically reduced construction costs in a variety of industries but may not have yet neared its potential in the transmission space.

Participants further discussed the potential for superconducting cables and using more dynamic line ratings. These innovations, along with new technologies, could benefit from more venture capital investment, which has historically flowed more into generation, and increasingly distribution, than transmission.

Other key features needed in a future U.S. grid include stronger mechanisms to prevent price dislocations, more underground transmission, a clearer framework to decide which types of lines are built (e.g., HVAC vs. HVDC), and more standardization of voltages. These topics were all highlighted and briefly discussed during the forum in Aspen.

Who: Action from a combination of entities

One central takeaway from Aspen's Transmission Forum is that incrementalism and business as usual will fail to build the transmission system that the United States requires. As one participant put it, "we cannot meet the transmission challenge with our standard processes." There is now an increasing urgency around transmission, yet the development of new projects remains too slow. Projects often take decades to become operational compared to pressures to build new lines in 2-3 years. Are existing entities in the power sector properly equipped to build transmission at the required speed and scale? And what about the supporting supply chain and public policies?

Participants in Aspen devoted significant time to discussing the roles of investor-owned, public-, and consumer-owned utilities and independent developers in building new transmission. Utilities play a major role in building transmission infrastructure by planning, owning, and managing transmission lines. However, the model of many utilities also brings inherent challenges to expanding transmission at the necessary speed and scale.

One major challenge, according to several participants, is that most utilities are only beginning to take a long-term view in their planning processes and investment decisions. Utilities increasingly need to be thinking about their individual needs over the next 20+ years rather than thinking three years out, as is common among many investment analysts deciding capital allocation. National needs and a view of the entire national system are similarly crucial for planning a transmission system that is cost-effective, reliable, and resilient.

The long-term capital investments required for long-distance, high-voltage transmission lines are challenging for most utilities. Many utilities lack the proper set of incentives to invest long-term capital. Vertically integrated utilities often have competing cost allocation decisions between generation, transmission, and distribution. They are frequently deciding to invest capital in replacing and adding to generation sources, as well as protecting distribution against wildfire risk. Investing limited capital in capital-intensive, long-lead time transmission projects (especially if the utility is not necessarily able to build/own the transmission) can be a difficult decision. The choice to invest in areas other than long-distance transmission provides benefits in the near term but foregoing transmission will ultimately increase long-term costs for the customer base. Capital for transmission may also be limited by high dividend payouts, according to one participant, which shrink the pool of profits available for reinvestment.

Revenue uncertainty may also inhibit building large, national-level transmission. Certain programs like the Department of Energy's Transmission Facilitation Program (TFP) tried to bridge this gap by providing revenue commitments, yet ultimately had too little funding to make a major impact. Participants mentioned that similar forms of insurance could help de-risk capital. Risk also influences the type of transmission projects that get built. Long-distance transmission often has a higher exposure to permitting risk and a similar, or lower, rate of return than an integrated package of local transmission projects. Interregional lines can also face higher capital costs and longer timelines, and are often subject to competitive bidding. On the aggregate, local lines have less risks and similar rate of return to regional and interregional projects. Capital will flow to local projects until incentives change. And several participants noted that within a capital-constrained environment there is definitely competition for capital between local and regional/interregional projects.

Despite obvious barriers, participants at Aspen highlighted the benefits that incumbent entities provide for building new transmission. Utilities often have important rights of way, skilled staff, and relationships with communities. Working with incumbents can help lower costs of a project and make it competitive. Vertically integrated utilities often also have a holistic view which can help with planning and decision making. Several participants pointed out that utilities have historically done a good job of meeting load growth in the United States. Utilities can continue to play a key role in U.S. transmission expansion if they communicate what they need, and then send signals for others to support them in drafting policy, building projects, and investing capital.

Importantly, participants in Aspen suggested that utilities may be open to partnerships with independent developers and/or state transmission authorities—there is recognition of the scope and scale of what is needed and openness to new relationships and structures. Each type of utility and independent developer brings different capabilities and constraints, and should find ways to partner. Investor-owned utilities (IOUs), for example, cannot carry development capital on the books for extended periods.

Legislators and regulators have a key role in creating proper incentives for other entities to plan and build transmission infrastructure. Participants agreed that the United States lacks the systems, incentives, and political will to expand the electric grid the way it did in the middle of the 20th century. There was significant discussion about the correct balance between competition and regulation. Several participants complained that overregulation is creating hurdles for investment and preventing markets from functioning efficiently. Permitting is another area with long time horizons and inefficient regulation that is disincentivizing transmission development.

A related issue that is adding risk to utilities' capability to invest in transmission is wildfire risks that can create large exposure and liabilities for utility shareholders. This has led to credit rating downgrades which has increased cost of debt and made all projects more expensive. If policymakers do not deal with these wildfire exposure issues, wildfire risk will likely continue to burden capital deployment into transmission projects and may limit the ability of utilities to invest in transmission.

Policy can play a variety of other important roles discussed throughout this report. Participants generally agreed on the need for more regulatory certainty and less policy whipsaws across political cycles. Numerous participants also discussed creative mechanisms for capital allocation, such as adopting a cap and floor model like that used in the United Kingdom to incentivize more financing for long-term, risky projects. More of these mechanisms are discussed in the "how" section of this report.

One group of entities that is not often discussed in the transmission space, but has potential to play a much larger role, is energy users. Very large consumers of electricity have now started to deploy more capital in the power sector. Various consumers have started to sign power purchase agreements and advance market commitments for clean firm generation, but these entities are so far less involved in transmission investment.

There may be a significant opportunity for large consumers of electricity to invest more in transmission. Many industrial users of electricity are increasingly worried about accessing affordable and reliable power. Long-distance, high-voltage transmission is one of the most important and economic means of solving the challenges these companies face. Meanwhile, large buyers of electricity have economic and political capital that the power sector sorely needs to build new transmission lines. According to one participant, many large consumers are currently basing their investments in generation within a credit, accounting, and incentive regime set up by World Resources Institute's Greenhouse Gas Protocol. Regional transmission organizations can create similar crediting regimes for buyers to invest in the grid.

Companies producing materials in the power supply chain are another key actor in solving the transmission challenge. The buildout of the U.S. electric grid will rely on a supply chain that can scale production and further standardize products while navigating trade tensions and uncertain signals of demand growth. Participants particularly emphasized a need for more production capacity of high-voltage transformers and mentioned that the White House should consider the Defense Production Act for electrical equipment.They also highlighted the importance of nurturing a more robust workforce of power engineers and electrical workers. Many participants supported the idea of launching a letter campaign to write to university departments and urge them to expand their programs for power system engineers.

Beyond utilities, policymakers, buyers, and supply chain companies, a variety of other entities also play key roles in transmission. Many of these groups were discussed in Aspen. Electric cooperatives (co-ops) are nimble and can move relatively fast in building new lines. Co-ops can be supportive of transmission but are sensitive to costs and face tricky capital allocation decisions around the tradeoff of investing in generation versus transmission. Public Utility Commissions (PUCs) and Regional Transmission Organizations (RTOs) play a critical role in planning and cost allocation, which will be elaborated in the "how" section of this report. Other entities, like Power Marketing Administrations (PMAs), were discussed less in Aspen but highlighted as important. PMAs are currently viewed by some as free riders but could play a role in interregional transfer.

Small customers and ratepayers are also important voices, especially in light of the affordability challenges facing state regulators and utilities. These customers often are heavily affected by changes in electricity prices. More broadly, the American public, of course, has an essential role in paying for and permitting the type of transmission system that they deem will most benefit them.

How: Planning, Paying, and Permitting

Planning is often referred to as the first of the "Three P's" of transmission. Participants in Aspen started by discussing several key principles of transmission planning. One such principle is that there will likely be no single grand plan to solve all transmission challenges across the United States. Rather, layered planning will occur at the local, regional, and interregional levels. Each of these processes inherently depend on one another, and a process with low coordination will lead to suboptimal outcomes for consumers.

These challenges motivated various participants to advocate for an anchor in the planning process. One participant described how the interstate highway system, for example, provided sufficient clarity for other roads to be built around the country. That level of national planning may not be politically realistic now. However, larger regional entities can play an important role in laying out clear, ambitious plans that can simultaneously be informed by, and guide, activity at the local level.

Planning entities will benefit from adopting a more holistic planning process that looks at distribution networks and incorporates that into transmission planning. Distribution assumptions should also be based on customer preferences. Additionally, participants noted that planning should be continuous. 10-year master plans will almost always prove ineffective. A better approach will constantly update assumptions and iterate on models.

PUCs and RTOs play a key role in planning long-distance transmission projects. State entities have an important responsibility in project siting and cost allocation. One participant noted that there is a large literacy gap between entities doing transmission planning and PUCs which are often understaffed and hesitant to greenlight billions of dollars in investment. It is important to ensure that PUCs are at the table in the planning process to be up to speed. If properly engaged, states and governors can play a large role in driving interregional and regional planning processes and bringing important entities to the table.

The Midcontinent Independent System Operators' (MISO) Multi-Value Projects (MVPs) are one example of projects driven by governors, while other models also exist like the Joint Targeted Interconnection Queue (JTIQ) study which was driven by independent system operator (ISO) CEOs. One participant mentioned that the Inflation Reduction Act earmarked $100 million for projects that include funding and capacity building for state efforts to work together and do planning.

On the RTO front, participants suggested that RTOs further use scenario-based planning to develop transmission that is "least regrets" and to help move through state regulatory processes. Several participants also mentioned that RTOs need to step up in playing a more pronounced role in facilitating transmission planning than they have over the last decade. There was broad agreement among participants that the United States cannot wait for a perfect solution but must rather work with the current grid to increase the current system and expand from there. Long-term, scenario-based planning, such as that required in FERC Order 1920 is a good starting point, and several RTOs and non-RTO areas are already moving in that direction.

Measuring and agreeing on benefits across geographic areas is one of the largest challenges for transmission planning. States often have different policy objectives and interpretations of electricity demand, but generally can agree on benefits like affordability and reliability. More metrics on these variables can help align PUCs on the need for regional and interregional transmission. Most participants agreed that creating industry standards for calculating cost, reliability, and resilience benefits is critical to advancing regional and interregional planning. The measurement and value of these benefits would ideally be agreed upon across regions.

Participants also discussed how transmission planning is not just about how to build new, but also how to use an existing system more efficiently. Grid enhancing technologies (GETS), for example, can expand the timeline for when the United States needs transmission. Innovative technologies like GETS are not a silver bullet and come with various challenges but should be considered as part of a portfolio and planning process.

Another innovation in transmission planning could come through the creation of new transmission authorities. One participant noted how transmission authorities are working well in Colorado and New Mexico. These authorities are designed to fill a gap and promote interregional projects that otherwise would not move forward. Transmission authorities can operate with the same legal authorities as IOUs and may help move new projects forward.

Paying is another key part of how to build transmission, and cost allocation was discussed extensively in the Aspen Transmission Forum. Spending on transmission continues to rise and consumers see that reflected in their bills at a rate that can outpace inflation. High costs limit the willingness of residential customers to pay for transmission. Meanwhile, there is often disagreement over benefits at the state level. Some states feel that they are paying too much for transmission while others are getting a free ride. Alternatively, some states may feel that they do not want to invest billions in transmission infrastructure which primarily benefits states other than their own.

Disagreement over cost allocation ultimately influences permitting and planning. One participant noted that "you have to figure out the payment before you get good implementation of planning and permitting." Another participant cited the case of the MISO-SPP JTIQ process in which planning only took nine months but cost allocation took 18 months to decide.

There was substantial debate among participants about the tradeoffs of mandatory versus voluntary cost allocation. Some participants argued to not jump ahead on the mandatory model and to give the voluntary model more of a chance. Voluntary cost allocation may be most successful in regions which already have pressure to move forward with transmission due to state policies. If all stakeholders feel invested in a long-term study and solutions are aligned, that can push forward the conversation on cost allocation.

Other participants were supportive of a more aggressive federal role in cost allocation. One participant proposed letting the Federal Energy Regulatory Commission (FERC) inform states that it will take charge of determining payments unless states can figure it out on their own within a defined period. According to the participant, this could be the most expedient way to build interregional transmission. Such a model would mean FERC must measure future benefits and allocate payment based on that. This will require clearly defining benefits and methods to estimate them. Benefits could then be remeasured every 2-5 years once a project is operational.

Several participants backed this idea and argued that FERC may have some latent authority to take on cost allocation, including through Order 1920, and unify planning, paying, and permitting for projects of national importance. However, another participant stated that FERC ultimately cannot mandate projects to be built. If FERC mandates a certain cost allocation method that states do not like, it is possible that the project may not get built.

Participants also discussed a variety of models that may be helpful for tackling cost allocation. One model that was discussed is the "Highway/Byway" model which is a cost-sharing framework used primarily by the Southwest Power Pool (SPP). This model bases payment on a project's voltage level. Regions pay 100% of costs of projects over 300kv. For projects of 100-300kV, regions pay 1/3 of the cost and local entities pay 2/3 of the cost since benefits are split regionally and locally. And for projects below 100kV, 100% of costs are borne at the local and county level within the transmission pricing zone. The Highway-Byway model seeks to optimize for fairness and simplicity. While benefit to cost (B/C) ratios are different across zones, the average B/C ratio of projects in SPP under this model was 5.76:1 and there were no zones in which the costs outweigh the benefits.

Another idea that was proposed was the open-network season model in which a developer announces the details of a project, customers submit requests for capacity and price offers, and the developer then allocates capacity. This model could be used for large load to calibrate the amount of incremental transmission investment to demand. It could also leverage the balance sheets of generation projects and offer them the right to interconnect to the grid in return.

Other models that were discussed include reliability-based payment systems and a hybrid cost recovery model. In the former, transmission owners could be compensated based on their contribution to system reliability, capturing the value of positive externalities. In the latter, consumers could cover the cost of debt, essentially paying the risk-free rate, with additional financial upside for developers based on performance once a project is operational. This model could help finance projects without forcing consumers to entirely fund long-lead time projects until they are used and useful.

The last of the "Three P's" is permitting**,** which is a decisive factor in determining how much, where, and when transmission is built. Most participants in Aspen agreed that the current permitting process in the United States is too slow to expand the country's transmission system at the necessary speed and scale. As one participant put it, "there is currently a large mismatch between the permitting queue and infrastructure needs." At the same time, participants stressed that removing environmental protections is not the correct solution to the problem. Permitting reform should be fundamentally about better process, not fewer rules.

Participants listed a variety of challenges to siting and permitting transmission lines in the United States. Several participants noted that the National Environmental Policy Act (NEPA) adds a high level of complexity, especially with state and local overlays and long appeal timelines. Reforms to NEPA are needed to balance public disclosure and engagement with efficiency, including less paperwork and quicker decisions. Various participants supported the idea of removing the NEPA requirement for the federal funding process.

There is increasing discussion of FERC also taking on more authority for federal permitting. Much has been made of FERC's current and potential backstop authority, but some participants were skeptical of the political tension that could result from making states go through a permitting process and then having the federal government explicitly overrule that process.

Strengthening agency capacity stands out as one relatively bipartisan solution to accelerate siting and permitting. More geospatial data analysis and data sharing between public agencies can help the siting process move quicker. Permitting can similarly benefit from using AI to streamline application accuracy and agency response, creating more top-level accountability for large-scale projects, and investing in staffing and training.

Several bolder ideas, albeit with less broad support from participants,were also offered to expedite permitting. One such solution could be allowing a "build and comply" approach for transmission in pre-zoned areas to skip repetition of the permitting process. Another proposed solution is to set tighter limits on project litigation. Legal challenges often increase customer costs, delay timelines, and reduce the appetite for project financing. Participants were also open to other creative solutions that could preserve transparency and public input but reduce delay and opposition.

Community benefits are a central component of a project's license to operate. As discussed earlier, communities are more likely to support new transmission projects if they can understand the benefits that transmission provides in terms of cost, reliability, and resilience. The onus is on players in the power sector to better define, measure, and communicate these benefits.

Another issue that is distinct from, but related to, permitting is right of way. There has historically been a general social compact that utilities serve local customers, so landowners would be willing to sell land at a low cost. These local benefits are more difficult to imagine for regional and interregional projects. Developers may now have to begin to pay more for rights of way. Utilities are mandated to follow financial prudency, but higher payments for right of way can help a project start sooner and thereby create meaningful value. One potential model to approach both community benefits and right of way could come from the oil and gas industry's use of equity payments. While this model has theoretical benefits, participants warned that it comes with numerous risks, including uncertainty of payment due to market conditions or changes in project ownership.

Much of the permitting challenge ultimately comes back to community buy-in, and most participants agreed that early, sustained community engagement is essential to de-risk projects. Taking that further, some participants argued that community engagement should be aggressive, ongoing, and a core business practice for transmission developers. Community engagement can help prevent delays and foster coalition building. In contrast, opposition often grows and litigation increases for projects without robust community engagement. Developers should also make a genuine effort to find the environmentally and socially least impactful routes for transmission.

Engagement alone is not sufficient for projects to get permitted. The permitting process itself needs to be made more efficient, project developers need strong environmental management plans, and there needs to be real investment in community benefits. Nonetheless, community engagement remains the foundation for forging the trust needed to build and sustain the future transmission system of the United States.

Agenda

Monday, February 3, 2025

Arrivals and Check-In

Opening Reception & Dinner

Tuesday, February 4, 2025

Welcome Remarks

Session 1: Grid Vision: What is the Ideal US Transmission End State

Session 2: What are the true barriers to transmission?

Session 3: What Are the Benefits and Drivers of Transmission?

Wednesday, February 5, 2025

Session 4: The Roles of Investor Owned, Public and Consumer Owned Utilities, and Independent Developers (and partnerships and hybrids)

Session 5: Getting From "Here" to "There" | Transmission Policy: Part 1 – Planning

Session 6: Getting From "Here" to "There" | Transmission Policy: Part 2 – Permitting

Session 7: Getting From "Here" to "There" | Transmission Policy: Part 3 – Paying

Thursday, February 6, 2025

Wrap Up and Forum Adjourns

Participant List

Attending Virtually *

1. **Scott Aaronson,** Senior Vice President, Security and Preparedness, Edison Electric Institute (EEI)
2. **Aaron Bloom,** Executive Director, Transmission Fundamentals, , NextEra Energy Resources
3. **Nicholas Bianco**, Program Director, Sequoia Climate Foundation
4. **Carlos Brown,** President–Dominion Energy Services and Executive Vice President, Chief Legal Officer, and Corporate Secretary, Dominion Energy
5. *__Susan Call__, Director, Installation Clean Energy & Energy Efficiency, Office of the Secretary of Defense for Energy, Installations and Environment
6. **Kent Chandler,** Resident Senior Fellow, R Street Institute
7. **Allison Clements,** Former Commissioner, Federal Energy Regulatory Commission (FERC)
8. ***Tony Clark**, Executive Director, The National Association of Regulatory Utility Commissioners (NARUC)
9. **Jim Connaughton,** Senior Advisor, Nautilus Data Technologies
10. **Jennifer Curran,** Senior Vice President, Planning and Operations,Midcontinent Independent System Operator (MISO)
11. **Katie Dykes,** Commissioner, Connecticut Department of Energy and Environmental Protection
12. **Mathias Einberger,** Climate Program Manager, The Hollyhock Foundation
13. ***Tom Falcone,** President, Large Public Power Council
14. **Miles Farmer,** Clean Energy Policy, Strategy, and Legal Consultant, Miles Farmer PLLC
15. **Joe Fina,** Senior FERC Counsel, Snohomish County Public Utility District
16. **Emily Fisher,** Chief Strategy Officer Smart Electric Power Alliance (SEPA) ***(Co-chair)***
17. **Anna Foglesong,** Managing Director, Clean Grid Initiative ***(Co-chair)***
18. **Larry Gasteiger**, Executive Director, WIRES
19. ***Brian George,** US Federal Lead, Global Energy Market Policy and Development, Google LLC
20. ***Jimmy Glotfelty,** Commissioner, Public Utility Commission of Texas (PUCT)
21. **Christy Goldfuss,** Executive Director, Natural Resources Defense Council (NRDC)
22. **Rob Gramlich,** Founder and President, Grid Strategies LLC ***(Co-chair)***
23. **Bryan Hannegan,** President and Chief Executive Officer, Holy Cross Energy
24. **Chris Hansen,** Chief Executive Officer, La Plata Electric Institute
25. **Christina Hayes,** Executive Director, Americans for a Clean Energy Grid (ACEG)
26. ***David Hayes,** Professor of Practice, Doerr School of Sustainability, Stanford Law School

27. **James Hewett,** Head, Power Sector Policy, Breakthrough Energy
28. **Lon Huber,** Senior Vice President,Duke Energy Corporation
29. ***Rebecca Isacowitz**, Deputy Assistant Secretary of Defense for Energy Resilience & Optimization, Office of the Secretary of Defense for Energy, Installations and Environment
30. **Alice Jackson,** Senior Vice President, System Strategy and Chief Planning Officer, Xcel Energy
31. **Alexina Jackson,** Managing Member, Seven Green Strategy
32. ***Bob Karr,** Co-Founder, The Hollyhock Foundation
33. **Travis Kavulla,** Vice President, Regulatory Affairs, NRG Energy
34. **Suedeen Kelly,** Partner and Co-Chair, Energy Practice, Jenner & Block, LLP
35. **Debbie Lew,** Executive Director, Energy Systems Integration Group (ESIG)
36. **Ray Long,** President and Chief Executive Officer, American Council on Renewable Energy (ACORE)
37. ***Richard S. Mroz,** Board Member, ClearPath Foundation
38. **Stuart Nachmias,** President and Chief Executive Officer, Con Edison Transmission, Inc.
39. **Aparna Narang,** Program Officer, Clean Grid Initiative
40. **Ben Norris,** Vice President, Regulatory Affairs, Solar Energy Industries Association (SEIA)
41. **Tanya Paslawski,** Founder, Elevated Engagement
42. **Rich Powell,** Chief Executive Officer , Clean Energy Buyers Association
43. **Patrick Reiten,** Senior Vice President, Public Policy, Berkshire Hathaway Energy
44. **Wilson Rickerson**, President, Converge Strategies, LLC
45. **Maria Robinson,** Former Director, Grid Deployment Office, U.S. Department of Energy
46. **Danielle Russo,** Executive Director, Center for Grid Security, SAFE
47. **Ronny Sandoval,** Managing Principal, Regulatory Assistance Project (RAP)
48. **Shashank Sane,** Executive Vice President, Transmission, Invenergy, LLC
49. **William Sauer**, Vice President, Federal Regulatory Affairs, Exelon Corporation
50. **Dan Schory,** Chief of Staff, Infrastructure, Arnold Ventures
51. **Camilo Serna,** Senior Vice President, Strategy and External Engagement, North American Electric Reliability Corporation (NERC)
52. **Michael Skelly,** Co Founder and Chief Executive Officer, Grid United
53. **Paul Suskie,** Executive Vice President and General Counsel, Southwest Power Pool (SPP)
54. ***Humayun Tai,** Co-Leader, Global Energy and Materials Practice, McKinsey & Company
55. **Jill Tauber,** Vice President, Litigation, Climate and Energy, Earthjustice
56. ***Nidhi Thakar**, Senior Vice President, Policy, Clean Energy Buyers Association (CEBA)
57. **Michael Webber,** Sid Richardson Chair in Public Affairs and John J McKetta Centennial Energy Chair in Engineering, University of Texas at Austin

58. **Laurie Williams**, Vice President, Integrated Planning, Public Service Company of New Mexico
59. **Martin Wyspianski**, Vice President, Electric Asset Management, Pacific Gas and Electric Company
60. **Carrie Zalewski,** Vice President, Transmission and Electricity Markets, American Clean Power Association (ACP)
61. **Avi Zevin**, Former Special Assistant to the President for Clean Energy Implementation, The White House

Aspen Institute Staff

1. **Greg Gershuny**, Executive Director and Vice President, Energy and Environment Program
2. **Tanzia Huq**, Program Associate, Energy and Environment Program
3. **Bea Kuijpers**, Program Manager, Energy and Climate, Energy and Environment Program
4. **Timothy Mason**, Director, Energy & Climate, Energy and Environment Program