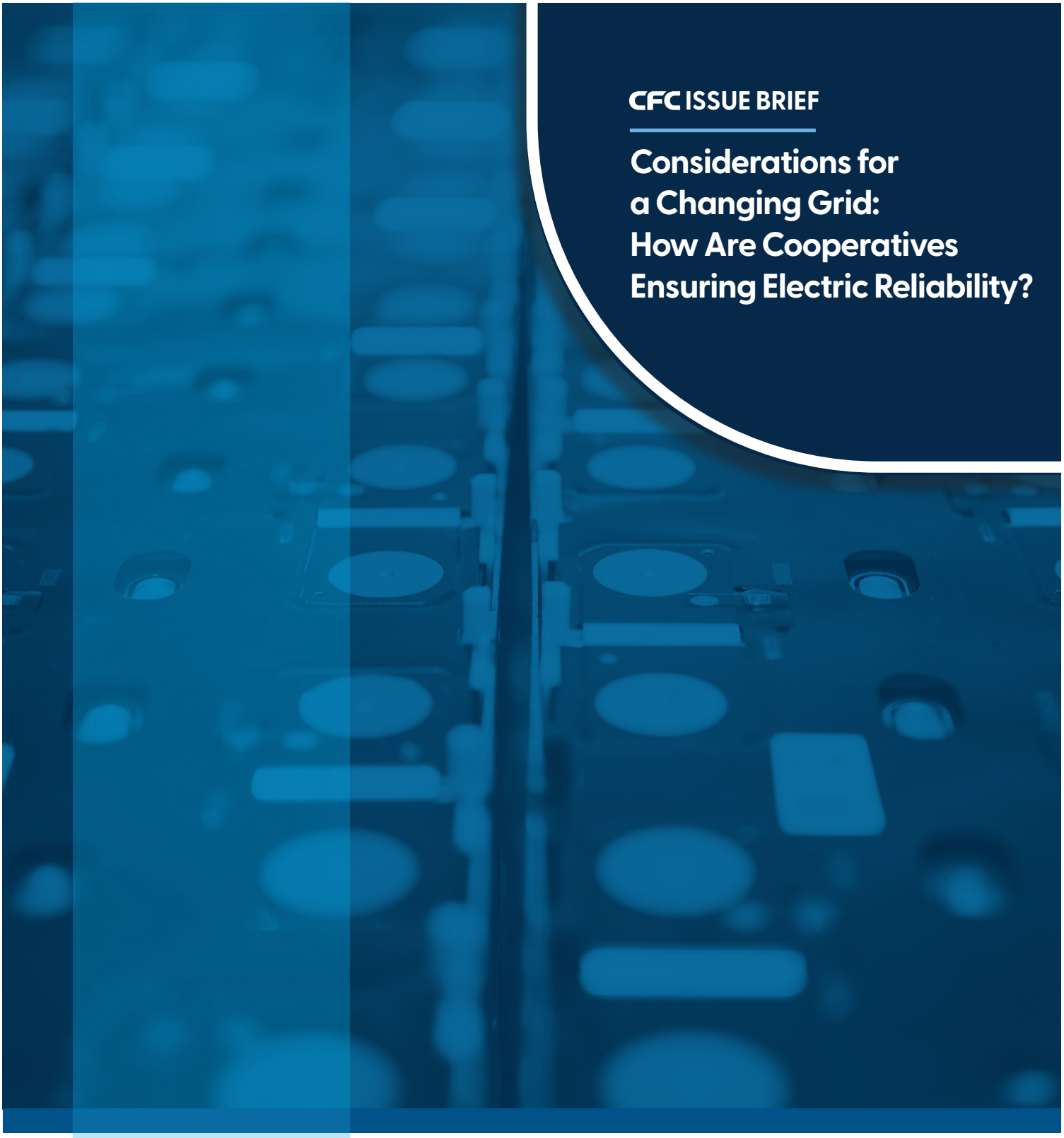


CFC ISSUE BRIEF

Considerations for a Changing Grid: How Are Cooperatives Ensuring Electric Reliability?

CFC
Cooperative Finance

Considerations for a Changing Grid: How are Cooperatives Ensuring Electric Reliability?

Electric reliability is top of mind as the U.S. grid enters a period of heightened complexity shaped by rapid load growth, shifts in the resource mix and growing constraints on how quickly infrastructure can be built. Electricity demand is now rising across much of the country, driven by data centers, manufacturing investment, population shifts and electrification of heating. According to the consulting firm Grid Strategies,[1] peak demand is expected to grow by 3.7% annually through 2030.

At the same time, large portions of the existing generation and transmission fleet are aging or retiring, placing enormous pressure on a grid that was not designed to handle today's rapid pace of change. These pressures are not uniform; reliability risks can vary sharply by region based on differences in load growth, resource availability, wholesale market dynamics, weather exposure, interconnection and developmental timelines, and transmission infrastructure. Some regions face acute, near term supply shortfalls as demand growth outpaces new supply while others are constrained by the ability to move power across congested networks to where it is needed most.

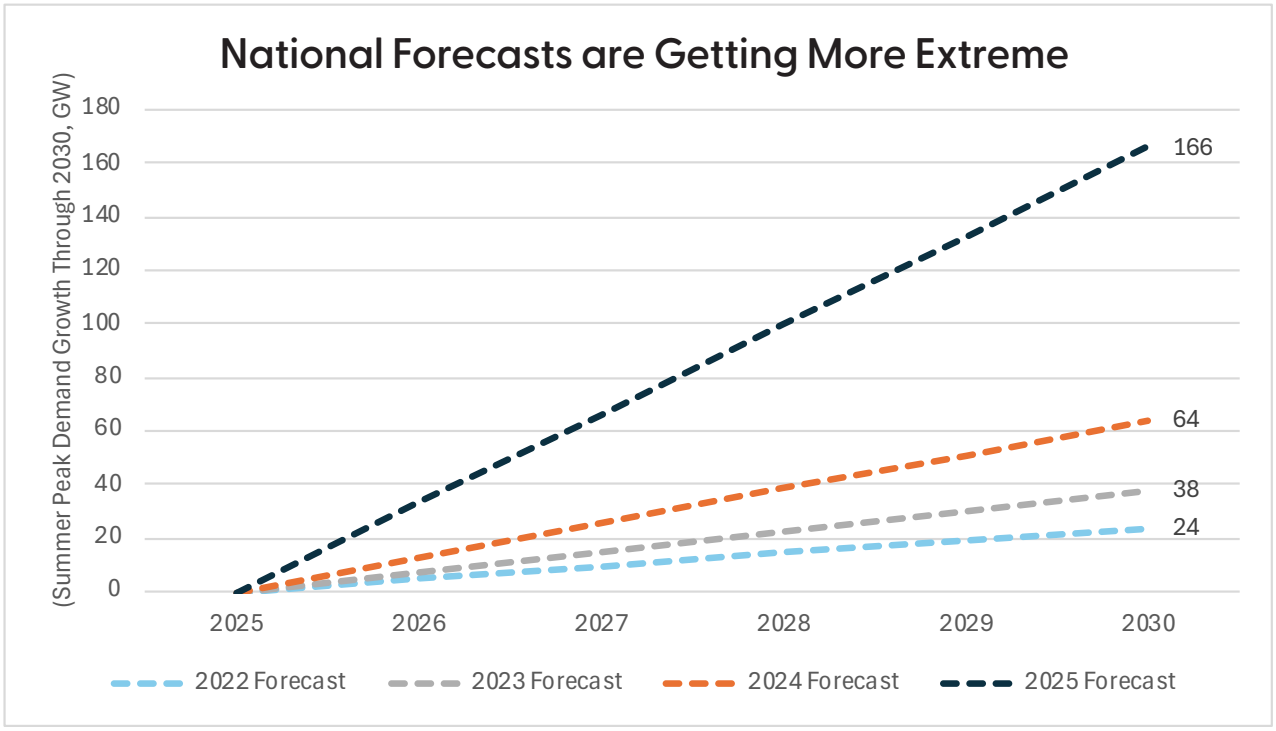
Extreme weather events, including winter storms, heat waves and wildfires, have further exposed how localized infrastructure limitations can become systemwide reliability challenges. Across both generation and transmission, a defining feature is execution risk. While the development pipeline for new infrastructure is historically large, projects face long lead times driven by permitting, interconnection studies, supply chain constraints and siting challenges. As a result, reliability planning is increasingly shaped not only by economic optimization, but also by what can physically be delivered on an aggressive timetable with a rising risk profile.

For electric cooperatives, reliability is foundational. Understanding how reliability risks are evolving and why experiences differ across the country is essential to making informed, durable infrastructure and investment decisions that align with this new environment.

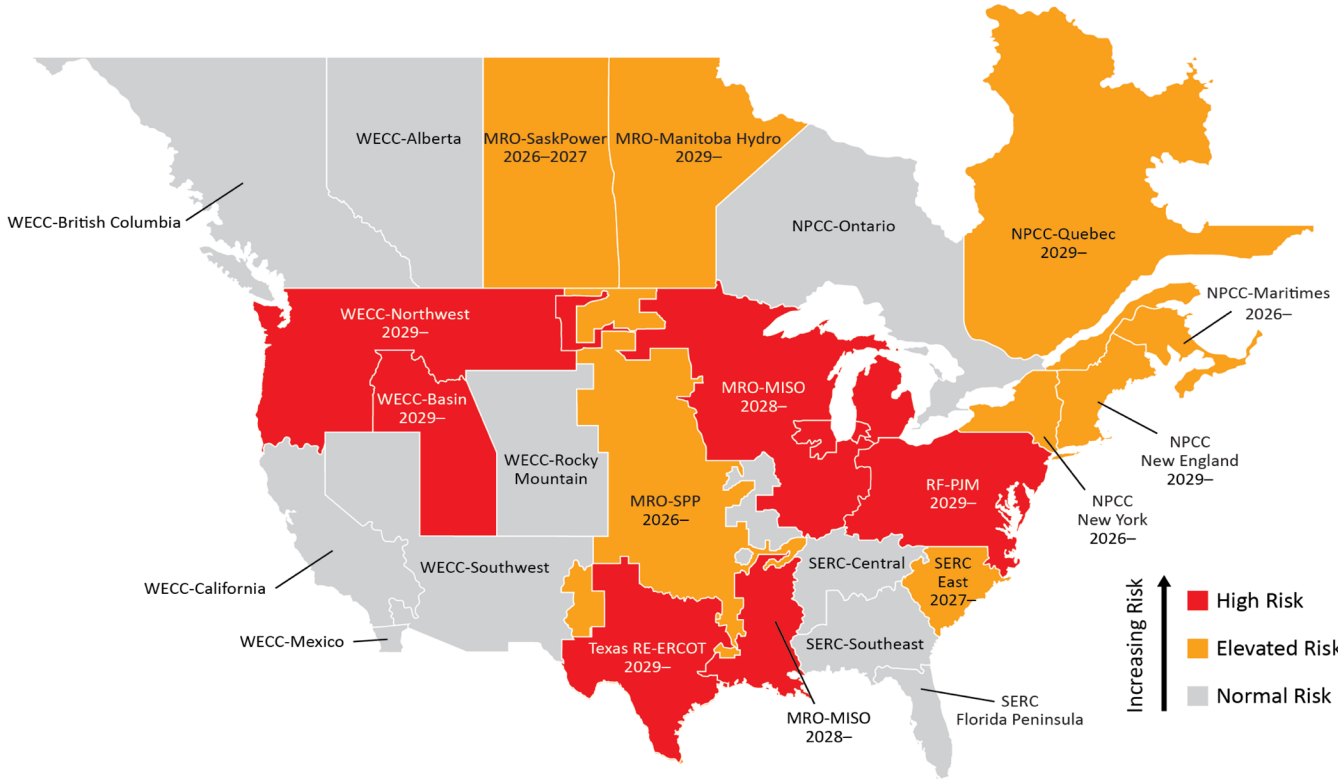
This issue brief explores the key trends shaping reliability nationwide and provides in-depth case studies from generation and transmission cooperatives who are actively working to address these challenges.

Generation Trends Shaping Reliability Risk

After more than a decade of relatively flat electricity consumption, the national outlook has shifted toward sustained load growth. The U.S. Energy Information Administration's 2026 Annual Energy Outlook forecasts rising electricity demand through 2050 and a need for substantial new generation to meet it. Large loads, especially data centers, are not only increasing demand; they are also changing how generation decisions are made. As



Source: Grid Strategies



The map shows NERC's capacity and energy risk assessments across the six regional entities of the North American Bulk Power System: Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst (RF), SERC Reliability Corporation (SERC), Texas Reliability Entity (Texas RE) and Western Electricity Coordinating Council (WECC). These entities are divided into 23 assessment areas, each rated as normal, elevated or high risk.

Source: NERC

data centers drive more growth in electricity demand, load shape and timing matter as much as total generation for cost and reliability. In response, utilities are increasingly moving toward contract innovation, generation funded by consumers and clearer risk allocation in generation planning.

At the same time, capacity needs are rising faster than energy demand because the resource mix increasingly relies on assets with lower capacity factors and different operating characteristics than the retiring fleet. Owners and operators plan to retire nearly 11 GW of utility-scale capacity in 2026—mostly coal (58%) and older gas steam/simple-cycle units (42%). A major caveat, however, is that retirements have become less predictable due to policy shifts and emergency extensions that postponed several coal plant closures last year. This uncertainty, layered on top of demand growth, is pushing utilities and G&T cooperatives toward a generation posture that prioritizes speed, flexibility and risk containment.

Despite the scale of resource retirements, the development pipeline is enormous—but delivery is slow and uncertain. The interconnection queue illustrates the gap between proposed generation and what can be counted on for resource adequacy. By the end of 2024, about 2,300 GW of generation and storage projects were actively seeking interconnection (roughly 1,400 GW of generation and 890 GW of storage). Yet only 13% of capacity (19% of the projects) requesting interconnection from 2000 to 2019 reached commercial operation by the end of 2024. Even when projects do get built, timelines have stretched: The typical project completed in 2024 took an average of 55 months from interconnection request to commercial operation, up from 36 months in 2015. In practice, permitting, network upgrades, study processes and equipment lead times now shape generation outcomes as much as fuel economics or technology costs.

The North American Electric Reliability Corporation's (NERC) long-term reliability assessment underscores what many utilities are already experiencing. As older fossil units retire, the resource mix is becoming more variable and weather dependent, with higher reliance on solar PV and battery storage. That shift increases the importance of essential reliability services, such as maintaining stable frequency and voltage. Batteries can support frequency regulations, while other inverter-based resources such as solar PV may contribute less without specific capabilities and operational practices. As renewables and storage grow rapidly, dispatchable capacity and system services remain central to reliability planning, particularly during extreme weather and steep ramp conditions.

Natural gas remains a key option for adding capacity, but fuel and market risk management is becoming more complicated. In the interconnection queue, natural gas capacity increased by 72% year over year in 2024, while solar, wind and storage each declined from 12% to 26%. Amid volatile gas markets and rising demand, utilities are incorporating more sophisticated fuel security and price risk strategies alongside traditional planning. Beyond financial hedging, many are pursuing physical exposure management, such as participating in gas storage to strengthen reliability and reduce vulnerability to

market disruptions. New technologies, like small modular nuclear reactors, nuclear fusion and enhanced geothermal systems, are gaining more attention across the country with a push to diversify resources. These technologies are still under development, being piloted or have yet to reach commercialization. While there are many new entrants into the space, the timelines for operationalization are expected to be five to seven years.

Today's new-build environment is defined by speed constraints, including equipment lead times, supply chain pressures and interconnection timelines. A defining feature of the current generation landscape is that decisions are increasingly governed by feasibility of execution—not economics alone. Lead times for new combined-cycle gas turbines have extended into multi-year windows, and development schedules are tightly coupled with ISO interconnection queues. To reduce risk, utilities are placing greater value on securing natural gas turbines and transformers early in the development process. Many are also moving toward long-term purchase agreements and larger inventories for critical equipment, such as breakers and transformers, to ensure systems can be built and maintained under high-growth conditions.

These operational constraints align with the broader reality reflected in interconnection queue data: Even with a large pipeline of proposed generation projects, uncertainty and delays threaten the pace of additions needed to keep up with demand growth. As a result, power supply planning is shifting away from just-in-time development toward early commitments, inventory strategies and risk-managed contracting—portfolios designed to be, above all, buildable, financeable and interconnectable.

Transmission Trends Shaping Reliability Risk

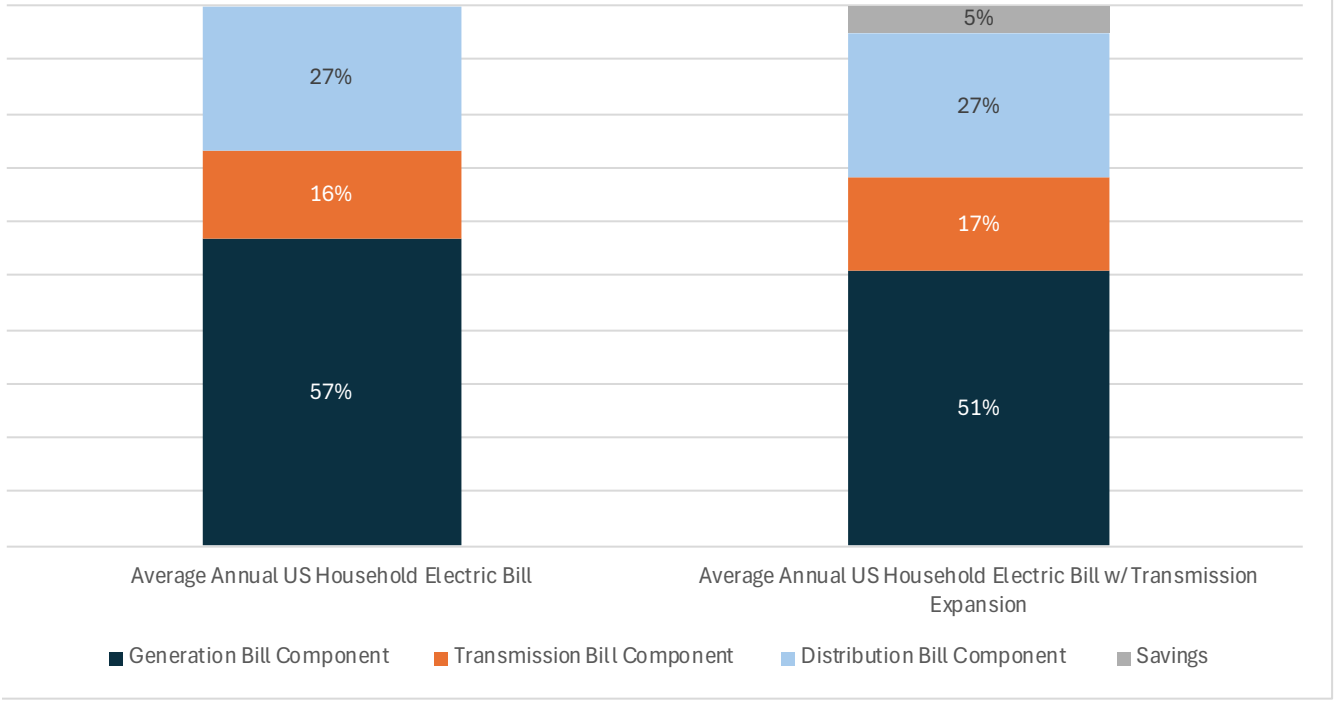
The power grid is under increasing pressure as electricity demand grows at unprecedented levels. Meeting that demand will be difficult without major investments to expand and modernize transmission infrastructure. In the coming years, electric cooperatives are expected to play a more active role in transmission planning and construction.

Despite a strong economic and reliability case, transmission projects often stall due to local opposition to development. New high voltage lines can span hundreds of miles, crossing multiple jurisdictions and private properties, which exposes projects to a wide range of landowner concerns. These concerns often center on visual impacts, perceived effects on property values, land-use restrictions and unease about construction or long term maintenance. While the benefits of transmission are broadly regional, the local and highly visible impacts are concentrated in a relatively small number of communities. This imbalance creates a classic "not in my backyard" dynamic that can translate into political pushback, litigation and lengthy delays.

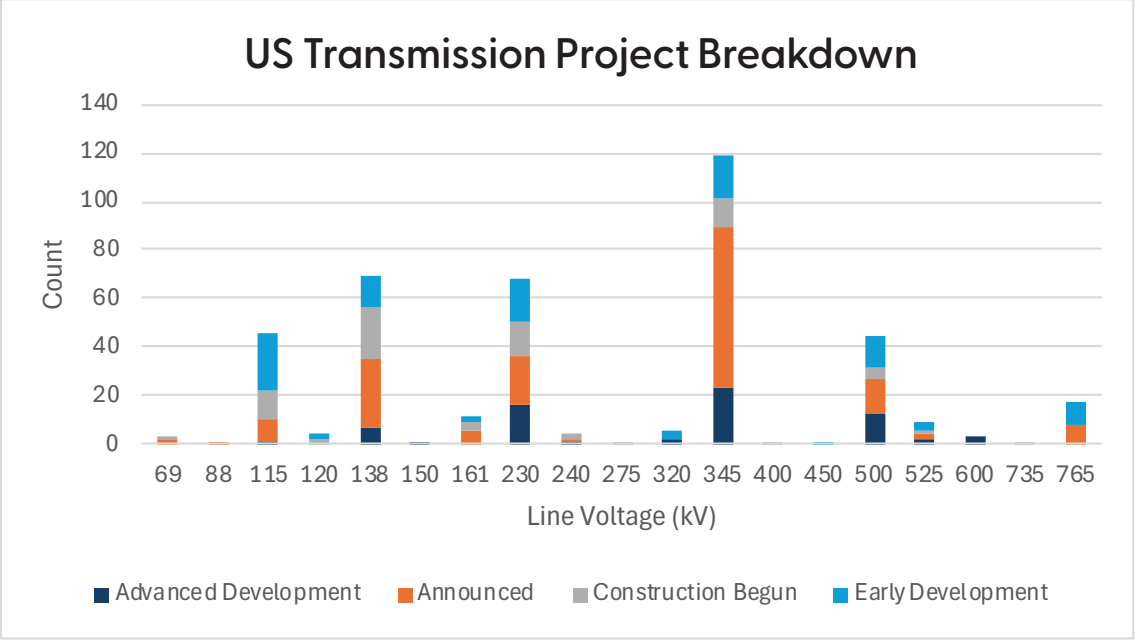
Opposition can be especially potent because transmission projects require extensive siting approvals and often lack a single, clearly defined local beneficiary. Unlike generation or economic development projects that may bring jobs or tax revenue to a specific community, transmission benefits are diffuse and systemwide, which can make local support harder to build.

Well-planned transmission projects can create significant economic value and cost savings for cooperative members and the need is quickly growing. Strategic transmission investments can reduce grid congestion, improve access to

Impact of Building High Voltage Transmission[2]



Source: Grid Strategies



Source: Grid Strategies

lower-cost generation, avoid or defer costlier investments in new generation, help manage fuel price volatility, support reliability during extreme weather events and improve overall system efficiency. With power demand rising rapidly, transmission infrastructure is critical to maintaining a reliable and affordable grid.

Transmission projects can require substantial upfront capital, but the value they create can exceed total project costs, particularly for high-voltage lines. According to a Grid Strategies report,[2] the same amount of power can be delivered at 75% lower cost using 765 kV high-capacity transmission compared with lower-capacity 230 kV alternatives.

In a review of 16 transmission studies or plans developed by ISO New England (ISO-NE), the New York Independent System Operator (NYISO), Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), the Electric Reliability Council of Texas (ERCOT), the Southeastern Regional Transmission Planning (SERTP) group and independent transmission developers, Grid Strategies found an average benefit-to-cost ratio of 3.8 to 4.7.[2] In other words, for every $1 invested in high-voltage transmission (345 kV and above), consumers could receive $3.80 to $4.70 in economic benefits, not including the economic benefits of construction.

Much of this value comes from production cost savings—reducing average power supply cost by increasing access to lower-cost generation. Grid Strategies[2] estimates that strategic investments in high-voltage transmission could increase the transmission component of a consumer's electricity bill by about 1% while lowering the generation component by more than 6%. That shift could translate into estimated savings of about $92 per year for an average household.

When the economic cost of an unreliable grid is included, the value proposition becomes even stronger. The cost of emergency load shedding events can be substantial—often in the thousands of dollars per MWh. Last year, the Federal Energy Regulatory Commission approved MISO's request to set the value of lost load at $10,000/MWh. As a result, outages can be hundreds of times more costly than the per-consumer cost of building new transmission at any voltage level. Because transmission delivers the most value during the relatively small number of high-risk hours each year, new infrastructure has the potential to recover a meaningful share of its costs over a limited number of critical periods.

Cooperatives can use new transmission to reduce reliability risk by increasing import and export capability, easing bottlenecks and congestion, expanding access to a broader set of generation resources and increasing the number of paths power can take across the grid. Together, these benefits can help cooperatives effectively manage supply shortages and maintain service during extreme weather events.

To capture these benefits while reducing delays, transmission developers and cooperative leaders will need to pair strong planning and economic analysis with early, transparent engagement in the communities most affected by new lines. Clear explanations of local impacts, thoughtful routing and mitigation, and credible commitments to landowner communication can help build trust and shorten timelines. With demand rising and reliability risks evolving, timely transmission investment is becoming a prerequisite for delivering affordable, dependable power to cooperative members.

There are currently 410 planned transmission projects in the U.S., spanning a range of voltage levels and developmental stages.

Photo courtesy of Rayburn Electric Cooperative

CFC CASE STUDIES

Photo courtesy of Dairyland Power Cooperative

Photo courtesy of Georgia Transmission Corporation

Rayburn Electric Cooperative Strengthens Reliability in Texas

Rayburn Electric Cooperative, a generation and transmission (G&T) system serving a predominantly residential footprint north and east of the Dallas–Fort Worth metro area, is facing a reliability landscape shaped by two converging forces: rapid load growth (about 6% annually) at the edge of the metro area and tightening supply conditions during extreme weather and evening ramp hours.

Rayburn serves four member-owned distribution cooperatives spread across 16 counties. As development pushes into member cooperative territories, Rayburn's planning horizon has compressed dramatically. "When we bought the Rayburn Energy Station (RES) in 2023, we didn't expect to fully step into that plant until 2030" said CEO, David Naylor. Instead, the G&T is already using the full generating capacity, prompting it to pursue additional capacity options sooner than planned.

Approximately 68% of Rayburn's generation supply comes from owned assets, with the remaining 32% provided through long-term contracts such as power purchase agreements (PPAs) and market purchases. After Winter Storm Uri wreaked havoc on the grid in 2021, Rayburn prioritized building and acquiring generation assets. To meet near-term reliability needs, the cooperative is developing 10 gas peaking units totaling 570 MW at the existing RES site, leveraging a brownfield location designed to accommodate expansion. Rayburn prioritized speed to service, modularity and operational fit over a larger combined-cycle build.

"When we looked at the risk, reward and cost—and how it fits our load—building just made more sense," Naylor said.

Rayburn hopes to finalize financing support through the Texas Energy Fund, a $10 billion state administered financing program that offers low-cost, long-term capital that helps protect member value, given that power supply costs account for the majority of member electric bills.

In parallel with new generation investments, Rayburn is strengthening its transmission system to improve reliability and flexibility across its footprint. Historically reliant on radial lines, the G&T is shifting toward a more redundant design by looping transmission lines and reducing single point of failure risk. By 2030, Rayburn expects roughly 75% of its transmission system to be looped up from about 30% in 2016. These efforts are complemented by substation upgrades, closer coordination with member distribution systems and expanded fiber and communications infrastructure to enable real time monitoring and faster response.

Like many utilities in Texas, Rayburn's load profile is highly weather sensitive, with winter storms and cold snaps driving sharp increases in demand and elevating operational risk during peak conditions. "Winter Storm Uri made it clear that we needed more firm options on both the supply and load side to manage risk when conditions deteriorate quickly." said Naylor. Rayburn and its member cooperatives are expanding distributed energy resource (DER) initiatives through residential battery partnerships with Base Power and new reliability-focused service models for commercial customers such as hospitals and big-box retailers. Rayburn's member cooperatives are also deploying conservation voltage reduction and connected-device programs (such as smart thermostats) to reduce coincident peaks and improve system economics.

Rayburn is also taking steps to address challenges that are outside of its direct control. Long lead times and supply chain timing have become central reliability variables, so Rayburn moved early to secure turbines and transformers to reduce schedule risk. The G&T also flagged a growing competitive dynamic: large customers, such as data centers, pursuing behind-the-meter generation outbidding utilities for equipment queues.

Gas market volatility is another key risk area. Rayburn pairs traditional gas hedging with physical risk-management tools. As new gas capacity comes online, the G&T has acquired a stake in a nearby gas storage project, which is expected to cover roughly 20% of its forecasted gas needs and improve supply assurance during market stress and extreme conditions.

Overall, Rayburn's approach reflects a broader shift in reliability planning, where success is increasingly defined by buildable capacity, dispatchable flexibility, grid redundancy and fuel security delivered on execution constrained timelines. Reflecting on Rayburn's experience, Naylor emphasized that meeting these challenges depends as much on organizational culture as on physical assets. Rather than waiting for perfect information, the G&T has prioritized decisiveness, early action and empowering teams to move quickly as conditions evolve.

That willingness to trust staff, accept calculated risk and adapt in real time has been central to Rayburn's ability to manage growth, extreme weather and market disruption while continuing to deliver reliable and affordable power to its members. That trust is built through deliberate investment in training, tools and leadership development so employees are prepared to act when it matters most.

As Naylor put it, "There's never been a challenge that Rayburn has faced that we have not overcome."

David Naylor
CEO, Rayburn

Dairyland Manages Reliability Amid Rapid Resource, Load Change

DAIRYLAND POWER COOPERATIVE
A Touchstone Energy® Cooperative

Dairyland Power Cooperative, a G&T system, operates in a region experiencing some of the fastest structural changes in the U.S. power industry. As a member of MISO since 2010, Dairyland is having to navigate fundamental shifts in generation mix, power flows, congestion patterns and load growth. The G&T is managing this challenge all while continuing to deliver high levels of reliability for its member distribution cooperatives across Wisconsin, Minnesota, Iowa and Illinois.

For much of the past decade, Dairyland's native load growth was modest, generally below 1% annually. The system serves growing rural and suburban areas, small and midsized industrial loads and is also seeing data center interest. More recently, Dairyland has added significant load by serving power supply customers that previously purchased power from neighboring investor-owned utilities. With this territorial expansion and new load additions, Dairyland's load outlook is closer to 1.5% annual growth, reinforcing the need for long-term generation and transmission planning rather than short-term optimization.

Dairyland's generation portfolio has also changed significantly over time. In the early 2000s, coal supplied nearly all generation (about 98%). By 2026, that share had fallen to less than 30% of the portfolio. This shift has been driven by a combination of diversification goals, economics and regional market dynamics. Dairyland's renewable portfolio is supported almost entirely through PPAs, including projects supported by the New Empowering Rural America (ERA) program.

At the same time, Dairyland has expanded its natural gas fleet, primarily through acquisitions rather than new construction. Since 2021, the cooperative has added roughly 1,800 MW of gas-fired capacity, including peaking resources in both MISO and PJM service territories. Dairyland views natural gas as a flexible capacity resource that supports reliability during periods of high demand, low renewable output or extreme weather.

"We've gone from relying on coal for reliability to needing firm gas supply, hedging fuel exposure and actively managing risk in commodity markets," explained Ronald Franz, Dairyland senior director of Resource & Energy Planning.

Storage is becoming an increasingly important part of Dairyland's reliability planning. Current initiatives include small behind-the-meter battery projects supported by federal grants and a solar-plus-storage project in Illinois that will pair a 50 MW solar facility with a 40 MWh battery system. Dairyland is using these projects as learning platforms both operationally and in market participation, especially for managing evening ramps when solar output declines and wind production can be uncertain.

Load management remains a key reliability tool, particularly in winter. Dairyland's ability to control dual-fuel heating, water heaters and other flexible loads has shifted the system's net peak toward summer, even though gross winter demand remains high. This capability provides important capacity relief during cold-weather events.

Ronald Franz
Dairyland Senior Director of Resource & Energy Planning

Dairyland's reliability strategy extends well beyond generation. As a transmission owner in MISO, the G&T has been an active participant in both near-term and long-range transmission planning, including MISO's Multi-Value Project portfolio and long-range transmission initiatives. Large-scale 345 kV projects—and Dairyland's first entry into 765 kV infrastructure—are intended to relieve congestion and move large amounts of low-cost renewable energy from wind-rich areas to load centers in Wisconsin and Illinois. These projects also support future resource additions and improve regional contingency performance.

"Moving the contingency out one level makes a big difference," Franz noted, describing how higher-voltage infrastructure can reduce reliability risks associated with outages and maintenance on lower-voltage lines. Overall, these projects are expected to deliver direct reliability and economic benefits to members and the broader region.

In addition to regional bulk transmission, Dairyland continues to invest heavily in its 69 kV and 161 kV systems, rebuild aging infrastructure, add fiber for greater visibility and control, and modernize load management and system-monitoring tools. These investments allow for more precise, real-time system operations and help mitigate congestion that can arise from broad, system-wide load control actions.

From Dairyland's perspective, reliability within its footprint remains strong. The bigger challenge is whether generation development, transmission expansion, permitting and supply chains can keep pace with accelerating load growth, particularly as AI, electrification and new industrial demand reshape the regional demand profile. Franz emphasized that these pressures are likely to show up first as higher costs and greater price volatility before they appear as traditional reliability events. Winter storms remain a key stress test, reinforcing the importance of fuel security, resource adequacy and regional coordination within MISO.

Dairyland's experience offers several lessons for other G&Ts and distribution cooperatives facing similar reliability challenges. Most important is the need for early, transparent engagement—both within the G&T and with member systems.

"The biggest thing is making sure everybody is pulling in the same direction across the organization and across the distribution co-op network," Franz said.

Dairyland has invested significant time in educating boards and member cooperatives about the changing reliability landscape, the risks being addressed and the rationale behind major capital investments. According to Franz, that groundwork, preceding final decisions, has been essential in building support for long-term strategies. He also stressed that there is no universal solution. Resource mixes, storage needs, load profiles and transmission constraints vary widely by region. Ultimately, successful reliability planning depends on aligning technical analysis with strong governance, clear communication and stakeholder trust—well before system stress makes those conversations urgent.

Georgia Transmission Takes Disciplined Approach to Transmission Reliability Amid Rapid Load Growth

Georgia Transmission Corporation operates in one of the most intensive transmission planning environments in the country. As load growth accelerates across Georgia, driven by data centers, industrial development and sustained residential growth around the state, Georgia Transmission is expanding and modernizing its transmission system while keeping reliability expectations front and center for the 38 electric membership corporations (EMCs) it serves.

As a transmission-focused cooperative, Georgia Transmission plans, builds and maintains the high-voltage transmission lines and substations that deliver power from generation resources to local distribution systems. Large-load inquiries vary widely in maturity, from speculative real estate developers to hyperscalers with highly detailed operating profiles. That variability has increased the importance of disciplined upfront system studies and clear expectations around data quality, redundancy and reliability requirements.

Georgia Transmission views reliability at two levels: bulk system performance and the day-to-day reliability experienced by its member cooperatives. Both are under pressure as new loads scale quickly and expectations for resilience continue to rise. System planning is anchored in N-1 contingency standards, ensuring the loss of any single major element does not interrupt system-wide service. In practice, this applies both locally, where large loads may require multiple transmission lines or substations, and upstream, where the broader network must be capable of delivering power reliably under contingency conditions.

A defining feature of Georgia Transmission's strategy is Georgia's Integrated Transmission System, which is jointly planned by Georgia Transmission, Georgia Power, the Municipal Electric Authority of Georgia and the City of Dalton. Each entity owns its facilities, but the system is planned and operated as an integrated whole. This model supports reliability, expands access to transmission across service territories and aligns with Georgia's long-standing retail choice framework for large loads.

Within the integrated system, Georgia Transmission manages its investment position relative to its share of load, referred to as "parity." Maintaining parity helps protect member value by avoiding settlement payments tied to higher investor-owned utility carrying charges. "We really prefer to be over-invested. We haven't been there in a long time but we're on a path to get there" explained Keith Daniel, Senior Vice President for Transmission Policy. To support both parity and reliability, GTC has selectively purchased transmission assets that serve member load. Ownership enables Georgia Transmission to apply its own maintenance standards, improve vegetation management, modernize facilities and directly address reliability issues that most affect its members.

Keith Daniel
Senior Vice President
for Transmission Policy

To keep pace with demand, Georgia Transmission is in the midst of a historic transmission buildout. Current plans comprise major new high-voltage projects, including new 500 kV transmission along with significant 230 kV and substation investments. These projects are part of a multi-billion-dollar, multi-year effort across the Peach State.

In parallel with capital expansion, Georgia Transmission has invested heavily in tools and processes that shorten outage duration and reduce member impact. These include remote-controlled, motor-operated switches supported by rigorous performance tracking, advanced fault location tools that quickly map probable fault locations and improved data flows to system operators and member cooperatives. Georgia Transmission has also prioritized system configurations that limit the number of substations affected by a single outage by adding sectionalizing capability and intermediate breaker stations.

Like many utilities, Georgia Transmission faces execution challenges tied to contractor availability, long equipment lead times and supply chain risk. In response, it has expanded contractor qualification processes, accelerated vendor approvals, increased inventory levels and secured long-term equipment supply agreements. These steps reflect a broader shift away from just-in-time practices toward resilience-focused planning.

Georgia Transmission's experience underscores several lessons for other transmission-focused cooperatives:

- Reliability planning is becoming more complex. Rapid, uncertain load growth increases the value of rigorous upfront studies, clear data requirements and early alignment on redundancy expectations.
- Bold transmission investment is increasingly unavoidable. Maintaining N-1 performance while serving significant growth often requires major high-voltage, substation and sectionalizing investments.
- Joint planning can create tangible reliability and access benefits. Georgia's integrated system model demonstrates how coordinated planning across owners can strengthen performance and flexibility.
- Operational tools matter as much as new steel in the ground. Remote switching, faster fault location and better operator-to-member information flows reduce the duration and breadth of challenges.
- Execution risk now needs its own strategy. Contractor constraints and long lead times require earlier procurement, stronger vendor management and inventory discipline.

Across each of these decisions, Georgia Transmission emphasizes a consistent objective: protecting and improving the reliability its member cooperatives can deliver to end-use members, even as Georgia's load growth reshapes transmission planning requirements.

PNGC Power Redefines Reliability in the Pacific Northwest

PNGC Power
Smart. Local. Connected.

For electric cooperatives in the Pacific Northwest, reliability is increasingly shaped by a combination of changing hydropower conditions, rapid load growth and constraints on how quickly new infrastructure can be built. The region has long relied on federal hydropower from the Bonneville Power Administration (BPA), but extreme weather, shifting water conditions, recent court rulings that diminish the output of hydropower, growing demand and policy constraints on new dispatchable generation are changing the risk profile. At the same time, BPA controls much of the region's transmission ownership and interconnection process, introducing execution risk into both generation development and load serving strategies.

PNGC Power, a G&T cooperative serving members across seven Western states, has responded by fundamentally rethinking how it plans for reliability, shifting away from a model built almost entirely around BPA supply toward one centered on flexibility and local control.

"When I joined PNGC, the Board was already asking the right strategic question: what does this organization need to become to serve members in the next era?" PNGC Power CEO Jessica Matlock said. "They recognized that the Northwest was entering a very different reliability environment, driven by load growth, data centers, transmission constraints and changing hydropower conditions. The conclusion was clear: PNGC's structure had to evolve to meet the future our members were facing."

A core element of PNGC's strategy is a redesigned power supply contract that provides members the flexibility to choose different resource pathways without forcing uniform decisions across a diverse membership. The contract breaks power supply into modular components: BPA Tier 1 hydropower (a base-rate block of low-cost power), BPA Tier 2 power for load above each member's load growth (some hydropower, but mostly market purchases), shared market resources, member specific generation, and PNGC led resource development. Members can choose the portfolio mix that best fits their needs while shielding nonparticipants (i.e., other members) from unwanted risk.

This structure has helped PNGC grow to 25 cooperative members while reducing the friction that can arise when resource strategies diverge. "The whole point was flexibility," Matlock said. "Power is changing dramatically and the contract needed to acknowledge that reality."

The model also enables secondary transactions among members, giving them tools to rebalance portfolios over time, manage carbon compliance across state lines and respond to shifting load forecasts without relying solely on volatile spot markets.

The most visible step in PNGC's reliability response is the development of a highly efficient 594 MW combined cycle natural gas plant in northern Idaho, the first of its kind in the G&T's service territory. The project reflects PNGC's view that sole ownership of dispatchable assets will be increasingly important for keeping rates affordable and meeting future reliability needs, particularly during extreme weather or low water conditions.

Jessica Matlock
PNGC Power, CEO

"Hydropower will always be a cornerstone of the Northwest power system, but it was not designed to carry every future reliability challenge by itself," Matlock said. "As loads grow and water conditions become less predictable, PNGC has to plan for a more diverse portfolio that can perform when members need power most." To improve execution certainty, PNGC structured the project through a tolling agreement with an experienced developer. While the plant is expected to come online in 2032, PNGC is already securing bridge power to manage near term reliability gaps.

Fuel security was another deciding factor. The plant is sited directly adjacent to the Gas Transmission Northwest pipeline, sourcing gas directly from Canadian gas fields further reduces market exposure to the more constrained and volatile supply dynamics elsewhere.

While dispatchable gas is central to PNGC's long term reliability planning, diversification also remains a core principle. The G&T is layering in solar, wind PPAs and a cooperative owned solar plus storage project supported in part by USDA New ERA funding. Geographic diversity across PNGC's wide footprint provides additional reliability value by smoothing weather driven variability and enabling internal balancing.

A lack of transmission ownership remains one of PNGC's largest reliability risks. Interconnection delays within BPA's system prompted PNGC to seek alternative balancing authorities for the gas project, underscoring the challenge of aligning generation development with transmission timelines outside the G&T's control.

Building transmission infrastructure allows PNGC to get the maximum value out of its geographically diverse service area, helps facilitate broader resource additions and ensures that the power generated can be efficiently delivered to where it's needed most across a very large territory. PNGC has begun engaging with regional transmission consortia and is exploring public private partnerships.

As PNGC weighs future investment decisions, market structure uncertainty adds another layer of complexity. PNGC expects to operate across multiple organized markets, reflecting overlapping balancing authorities and evolving regional market designs in the West.

PNGC will also consider evaluating longer term options, including peaking resources, geothermal energy, and small modular nuclear reactors, while closely watching transmission feasibility as a gating constraint.

"A project can pencil beautifully on paper, but the real test is whether you can connect it, deliver it, and build it on time," Matlock said. "Transmission constraints, interconnection delays, and long equipment lead times can change both the cost and the schedule dramatically. That is the practical reality facing every utility trying to add reliable resources right now. Drawing on experience across multiple utilities, Matlock emphasized execution realism and relationship management as critical lessons for cooperatives navigating today's reliability environment. She noted that early stage pricing signals, particularly from competitive solicitations, often understate true project costs and should be viewed as directional rather than definitive, especially in an environment of rising input prices and long lead times.

Having trusted development partners becomes critical as projects advance, particularly when costs escalate or timelines shift, Matlock said. She also highlighted the long term value of ownership and local control, noting that while developing generation assets is capital intensive and complex, it provides members with greater certainty, governance influence, and alignment with cooperative principles—advantages that become increasingly important amid growing reliability risk and market uncertainty.

Key Reliability Trends Across the Sector

The following reliability trends are increasingly shaping power supply dynamics and investment decision-making in the electric cooperative industry:

1. **Reliability risk is becoming more regional, localized and uneven.** Reliability challenges are no longer well explained by national averages; they are increasingly shaped by regional resource mix, transmission infrastructure, wholesale market design and weather exposure.

2. **Load growth is outpacing infrastructure timelines.** Demand growth—especially from data centers, electrification, manufacturing investment and population shifts—is accelerating faster than generation and transmission can be planned, studied and built. Even where growth is modest in percentage terms, today's supply-side conditions make systems more sensitive to unexpected shocks.

3. **Execution constraints now define reliability outcomes.** Interconnection queues, equipment lead times, contractor availability and permitting risk can be as consequential as resource economics. Cooperatives are shifting from least cost optimization to solutions that are buildable, financeable and deliverable on time, prioritizing speed and flexibility.

4. **Dispatchable capacity remains essential—even in diversified portfolios.** Despite growth in renewables and storage, dispatchable resources remain central to maintaining reliability during periods of extreme weather and growing demand.

5. **Transmission is becoming the binding constraint for reliability and growth.** Transmission networks are increasingly the critical lever for strengthening reliability and unlocking economic value. Strategic transmission investment and coordination can improve system resilience, expand access to resources, reduce congestion and better position regions to accommodate sustained load growth.

6. **Reliability planning is becoming more holistic.** Generation, transmission, fuel supply, markets, distributed resources and load flexibility are no longer separate decisions. Cooperatives are integrating these elements into a single reliability framework that links resource planning, transmission planning, fuel strategy, demand response and market participation.

7. **Governance and organizational agility matter more than ever.** Reliability outcomes increasingly depend on decisive governance, internal alignment and ongoing board education. Waiting for perfect information is less viable in a fast-changing environment; cooperatives that act early and empower staff tend to build resilience, even under uncertain conditions.

Key Considerations for Navigating Today's Reliability Environment

Cooperatives could consider the following when addressing the challenges of today's reliability environment:

- **Plan for uncertainty:** Assume costs will rise, timelines will stretch and execution risk will increasingly shape outcomes.

- **Stress test plans against real-world constraints:** Evaluate interconnection timing, equipment delivery, workforce availability and permitting risk—not just economics.

- **Secure flexibility before you need it:** Maintain a range of options such as modular generation, flexible contracts, looped transmission, secondary markets or load control to preserve future choices.

- **Consider alternative approaches to managing peak:** Interruptible load, DERs, energy storage, smart devices and targeted demand response can reduce on-peak risk and improve system economics. Cooperatives with strong member relationships are well positioned to deploy load side reliability tools.

- **Communicate early and often with members and policymakers:** Reliability investments are capital intensive and long lived. Proactive education and transparency can build trust and reduce the likelihood of reactive decision making once system stress is already present.

- **Anchor decisions in cooperative principles:** Across the case studies, a recurring lesson is the value of local control, ownership and governance. While ownership is not always the answer, cooperatives that retain influence over critical assets and decisions often gain more certainty in an increasingly volatile reliability landscape.

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