Utility Perspectives on Making Grid-Enhancing Technologies Work

USE CASES, BARRIERS, AND RECOMMENDATIONS FOR SCALABLE DEPLOYMENT

A Report by the
Energy Systems Integration Group's
Grid-Enhancing Technologies User Group

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ESIG
ENERGY SYSTEMS INTEGRATION GROUP

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Utility Perspectives on Making Grid-Enhancing Technologies Work: Use Cases, Barriers, and Recommendations for Scalable Deployment

A Report by the Energy Systems Integration Group's Grid-Enhancing Technologies User Group

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A listing of organizations participating in the GETs User Group is provided in the appendix.

Disclaimer

This report was produced by the ESIG Grid-Enhancing Technologies User Group, which includes a variety of members with differing viewpoints and levels of participation. Specific statements may not necessarily reflect a consensus among all participants or the views of the participants' employers.

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Abbreviations

AAR	Ambient adjusted rating
ACCC	Aluminum conductor composite core
ACCR	Aluminum conductor composite reinforced
ACSR	Aluminum conductor steel-reinforced
ACSS	Aluminum conductor steel-supported
AECC	Aluminum encapsulated carbon core
AEP	American Electric Power
APFC	Advanced power flow control
ATT	Advanced [or alternative] transmission technology
CIP	[NERC] Critical Infrastructure Protection
DLR	Dynamic line rating
DOE	Department of Energy
EMS	Energy management system
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GET	Grid-enhancing technology
INL	Idaho National Laboratory
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
SCADA	Supervisory control and data acquisition
SPP	Southwest Power Pool
TTO	Transmission topology optimization

Executive Summary

The U.S. electricity transmission grid stands at a pivotal moment, presenting both challenges and opportunities. Rising demand, changes to the resource mix, a growing backlog of generation interconnection requests, and an aging grid infrastructure are converging—resulting in mounting reliability concerns, escalating congestion costs, and strain on the system's ability to respond flexibly and efficiently.

Major transmission expansion is essential. Long-term reliability and efficiency depend on sustained investment in high-capacity transmission, regional build-outs, and interregional ties. These projects are foundational to a modern, resilient grid—but they take time. Permitting, siting, and constructing new transmission lines can take many years, even when the need is urgent and the benefits are clear.

Deploying Flexible, Scalable Technologies to Improve System Performance

To address immediate needs while those projects advance, a complementary strategy is required—one that deploys flexible, scalable technologies to improve system performance today. Grid-enhancing technologies (GETs) offer exactly that. These tools—including dynamic line rating (DLR), advanced conductors, advanced power flow control (APFC), and transmission topology optimization (TTO)—can unlock underutilized capacity, reroute flows around congestion, and improve the efficiency and adaptability of existing infrastructure. Many can be installed and operational in a matter of months, often without new rights-of-way, and at a fraction of the cost of traditional upgrades.

Each technology supports the grid differently. DLR adjusts thermal line ratings based on real-time weather conditions, allowing more power to flow when conditions are favorable. APFC uses modular devices to dynamically redirect power flows across the network, relieving bottlenecks and balancing load. TTO enables grid operators to reconfigure transmission topology in response to changing system needs, using switching actions that can reduce congestion and enhance reliability. Advanced conductors—such as ACCC (aluminum conductor composite core), ACCR (aluminum conductor composite reinforced), and ACSS/TW (aluminum conductor steel-supported/trapezoidal wire)—can double the capacity of existing lines without changing the supporting structures, often preserving or improving ground clearances.

Demonstrating Deployment and Strategic Use

These technologies are already being deployed. PPL Electric achieved a 15% increase in line rating using DLR, resulting in $64 million in congestion cost savings

A growing number of utilities and system operators are beginning to integrate these technologies into their planning and operations, reflecting a broader shift toward more flexible and adaptive grid solutions.

in one year. Southern California Edison has installed more than 385 miles of composite-core conductors and plans to reconductor 300 to 400 additional miles to accommodate growing load and system needs. The Midcontinent Independent System Operator and Electric Reliability Council of Texas have adopted TTO as part of their market operations and congestion management, enabling reconfiguration of the system to improve performance under real-world conditions. These examples show that GETs are practical, proven, and scalable.

GETs can be applied incrementally and strategically. Their modularity allows planners to target high-impact areas, and their flexibility supports adaptation as new transmission, generation, or loads are introduced. In many cases, GETs can ease near-term pressures while longer-term infrastructure solutions are developed. This ability to address constraints quickly and cost-effectively makes them a valuable complement to long-term grid planning.

Addressing Implementation Concerns

There are also valid concerns around implementation, which are also addressed in the report. Some planners remain cautious about how to model GETs, represent them in long-term studies, or evaluate asset performance over time. Others point to institutional barriers, such as unclear cost recovery, limited field standards, or internal misalignment between departments. Many of these challenges are already being addressed. GETs can be incorporated into existing tools like production cost models and power flow simulations. Asset management practices are evolving, and utilities are beginning to track and maintain GETs alongside traditional infrastructure. Regulators are exploring incentive structures, such as performance incentives, to encourage deployment.

GETs may not be the right fit in every situation, but they need to be thoughtfully and routinely evaluated as part of the full set of potential solutions to many of today's most pressing transmission challenges. A growing number of utilities and system operators are beginning to integrate these technologies into their planning and operations, reflecting a broader shift toward more flexible and adaptive grid solutions.

This report synthesizes utility experience, planning guidance, regulatory action, and real-world deployment examples. It outlines practical steps to accelerate the adoption of GETs, clarify modeling practices, align incentives, and integrate these tools into planning, markets, and operations. By working collaboratively across the industry, stakeholders can move GETs from pilot programs to standard practice—ensuring the grid is equipped to meet the demands of today and the future, while long-term transmission projects are planned and built.

Modern Grid Challenges Require Transformative Solutions

The U.S. electricity transmission grid stands at a pivotal moment, presenting both challenges and opportunities. Rising demand, changes to the resource mix, a growing backlog of generation interconnection requests, and an aging grid infrastructure are converging, resulting in reliability challenges and increased costs. Investing in new transmission infrastructure and embracing innovative solutions can help address these issues, reduce congestion, increase system flexibility, and create a more affordable and robust grid.

The situation calls for action. In 2022, grid congestion costs in the U.S. exceeded $20 billion, straining operations and reducing system efficiency (Doying, Goggin, and Sherman, 2023). Simultaneously, over 2,600 GW of generation and storage projects—more than double the total installed capacity of the U.S. grid—are waiting in interconnection queues, unable to connect due to transmission limitations (LBNL, 2024). Moreover, electricity demand is surging, with data centers alone projected to triple their share of U.S. electricity consumption within the next decade, rising from 4% to 12%—equivalent to 130 GW of new demand (Shehabi et al., 2024). But while these changes introduce new complexities, they also create exciting opportunities to modernize and optimize the grid for a more efficient, reliable, and cost-effective future.

A Dual Imperative: Long-Term Needs for Transmission Expansion and Short-Term Optimization of the Existing Grid

Major transmission expansion is essential to unlock generation, ensure reliability, and prepare for future demand growth. However, permitting, siting, and constructing new transmission lines often take a decade or longer. To address urgent constraints while long-term solutions are developed, a complementary strategy is needed—one that deploys flexible, scalable technologies to improve system performance today.

- **Long-term transmission expansion:** Long-term needs require large-scale transmission expansion and modernization, including large-scale investments in high-capacity transmission corridors, regional grid build-outs, and interregional connections.
- **Optimizing the existing grid:** Near-term solutions, such as grid-enhancing technologies (GETs), can maximize the capacity of existing infrastructure, providing relief while new lines are planned and built, and offering capabilities that can be integrated into the expanded system.

GETs' Benefits

GETs are not a wholesale substitute for long-term transmission investment, but they play an increasingly important role in strengthening the system in the near term. As interest in these tools grows, it is essential that they enhance—rather than distract from—the sustained planning, coordination, and investment required to build out the grid at scale. A balanced strategy can unlock immediate value while reinforcing long-term goals.

A balanced strategy can unlock immediate value while reinforcing long-term goals.

Unlike traditional transmission projects that often take several years or more, GETs—including dynamic line rating (DLR), advanced power flow control (APFC), transmission topology optimization (TTO), and advanced conductors—can be deployed in months. These technologies can increase capacity on existing transmission paths, improve efficiency and lower costs by unlocking low-cost supply resources, accelerate interconnection of generators and loads, and improve resilience—often at a fraction of the cost of new transmission.

And Challenges

Although the benefits of GETs are clear, several challenges remain, including complexities in system integration, a comparatively low level of deployment and practical experience, and regulatory and incentive-related obstacles. Progress can also be hindered by organizational resistance to change and the need for skilled personnel to effectively manage these technologies. Nevertheless, targeted strategies, such as pilot programs, workforce training, and supportive regulatory frameworks, are beginning to address these issues collectively, thanks to the collaborative efforts of utilities, vendors, researchers, and regulatory bodies.

While GETs are neither a cure-all nor a replacement for the substantial transmission expansions required to meet large-scale system needs, they serve as a critical bridge and complement these efforts. By pursuing both approaches in tandem, we can ensure a resilient grid that meets the demands of changing system conditions and future reliability needs.

While GETs are neither a cure-all nor a replacement for the substantial transmission expansions required to meet large-scale system needs, they serve as a critical bridge and complement these efforts. By pursuing both approaches in tandem, we can ensure a resilient grid that meets the demands of changing system conditions and future reliability needs.

In 2023, ESIG launched the Grid-Enhancing Technologies (GETs) User Group—a diverse group of transmission utilities and system operators that are actively using or planning to use GETs. The group serves as a trusted forum for sharing operational experience, identifying value streams, and exchanging best practices. Members collaborate on practical challenges, policy implications, and integration strategies across planning and operations. Regular meetings foster open dialogue, peer learning, and collaborative problem-solving, tailored to the specific needs of participating organizations.

The group's primary focus has been on four GETs:

- DLR
- APFC
- TTO (reconfiguration)
- Advanced conductors[1]

This report provides a brief description of GETs, a brief history of initiatives and policy decisions related to GETs, and a summary of the findings from the GETs User Group. It concludes with a possible path forward that includes various actions coming out of the user's group discussions.

The Opportunity: Grid-Enhancing Technologies

GETs offer valuable flexibility for managing uncertainty and improving grid performance under a range of future conditions. They can offer a least-regrets solution, allowing utilities to maximize the use of existing infrastructure while allowing time to thoughtfully plan and implement longer-term transmission upgrades.

There is growing momentum behind the adoption of GETs. Success stories from various utilities and system operators highlight the effectiveness of GETs. Several utilities and independent system operators are actively utilizing GETs, showing that these technologies are practical solutions with immediate impact. A few success stories include:

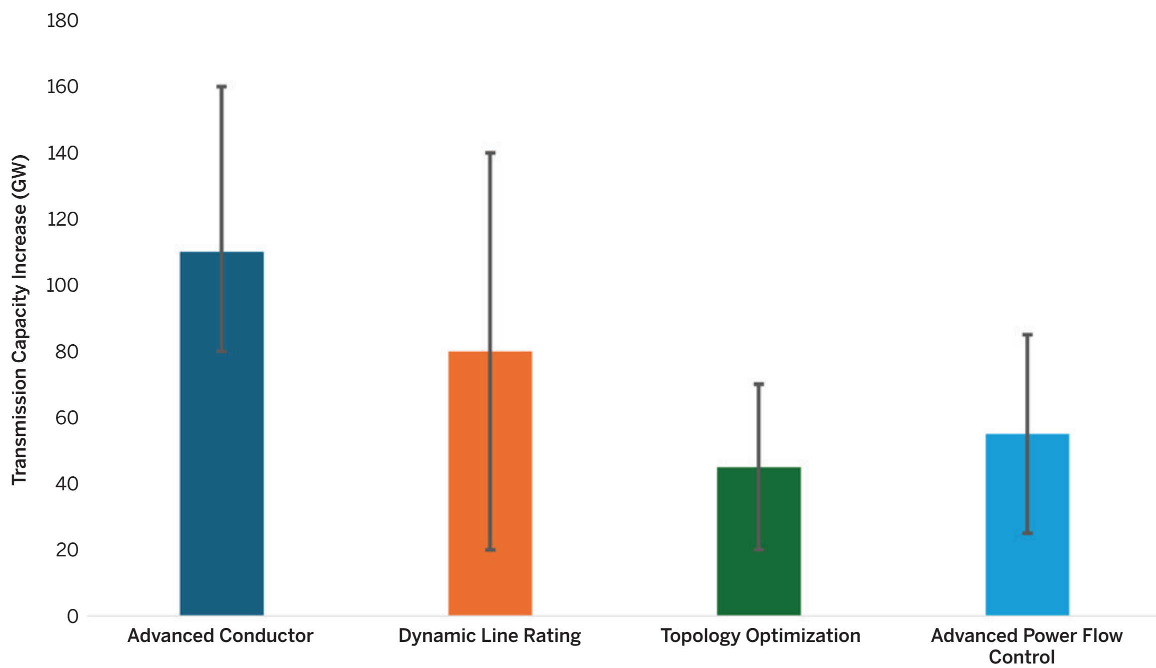
- **DLR:** Pennsylvania Power and Light Electric (PPL) deployed DLR on several lines, achieving a 15% increase in transmission capacity during cooler weather and saving $64 million in congestion costs in one year with an investment of less than $1 million (PPL, 2022).
- **Advanced conductors:** American Electric Power (AEP) upgraded two 120-mile 345 kV lines in Texas, increasing capacity by 40% without needing new rights-of-way (Energy Biz, 2016). Similarly, Southern California Edison installed 385 miles of these conductors to support load growth and generation integration (Driscoll, 2024).
- **APFC:** National Grid (UK) implemented modular power flow controllers at three substations, unlocking 1.5 GW of additional renewable capacity and saving $500 million over a seven-year period (National Grid, 2021b).
- **TTO:** The Midcontinent Independent System Operator (MISO) has implemented a process that allows stakeholders to request targeted reconfigurations of the transmission system to reduce congestion. In 2024, this approach delivered an estimated $24 million in congestion savings (MISO, 2024).

Studies using advanced markets and operations simulation tools have also shown the potential savings that deploying GETs at a large scale can achieve, typically focused on quantifying the reduction in congestion costs. A study by the Rocky Mountain Institute (RMI) showed that the PJM region could achieve approximately $1 billion per year in production cost savings by using DLR, APFC, and TTO (Siegner et al., 2024). A study on DLR and APFC in New England demonstrated significant reductions in variable energy curtailment, with payback periods of only a few months. Idaho National Laboratory (INL) has also documented the piloting and deployment of these technologies through a series of reports (Abboud et al., 2022; INL, 2024a; INL, 2024e).

1 Some entities, including the Federal Energy Regulatory Commission, categorize advanced conductors as an "alternative transmission technology" and may not include it in their explicit set of GETs. We include it as a GET in this report but recognize there may be some reasons that other organizations have different classifications.

FIGURE 1

Estimated Transmission Capacity Unlocked by Selected Grid-Enhancing Technologies



The deployment of advanced conductors, DLR, TTO, and APFC can unlock between 20 and 160 GW of effective capacity on the U.S. grid. These gains reflect potential opportunities for cost-effective upgrades to existing infrastructure, as outlined in the U.S. DOE's *Pathways to Commercial Liftoff* report.

Source: White et al. (2024); U.S. Department of Energy.

The U.S. Department of Energy's report *Pathways to Commercial Liftoff: Innovative Grid Deployment* highlights how the implementation of these advanced grid solutions, which are commercially available today, can increase the existing grid's capacity to handle an additional 20 to 100 GW of peak demand when installed individually, and even more when used in combination (White et al., 2024) (Figure 1 and Figure 2, p. 5).

The Main Grid-Enhancing Technologies Available

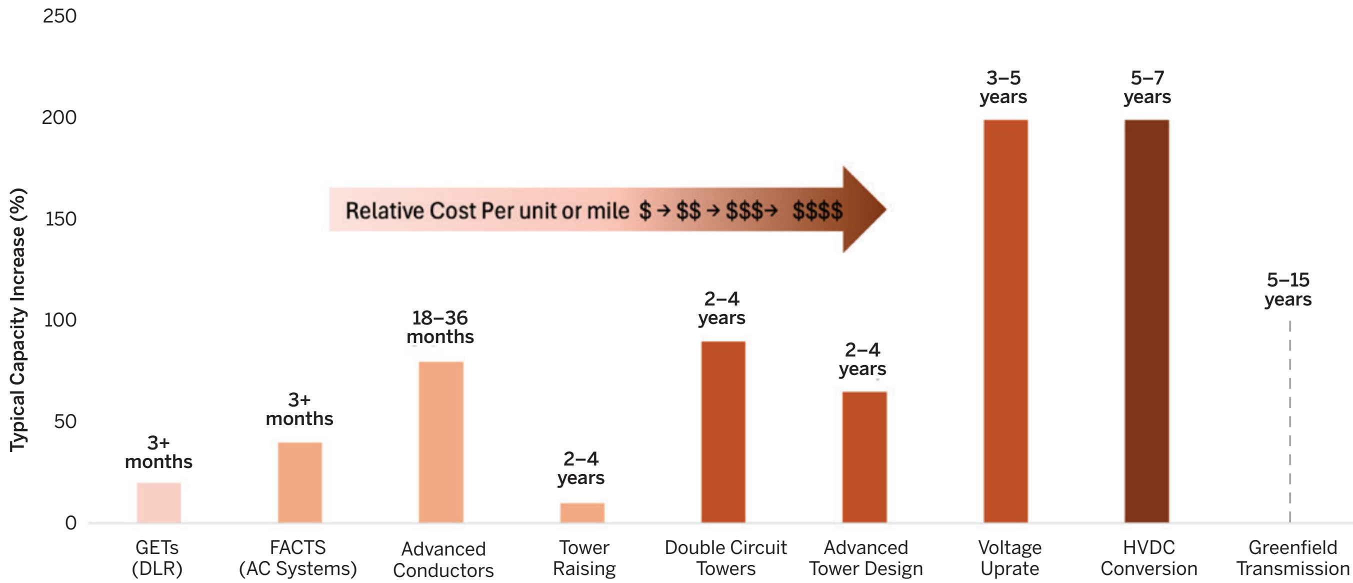
GETs include hardware and software designed to improve the management of the existing network by allowing more power to flow or allowing it to flow more efficiently. The leading technologies discussed by ESIG's Grid-Enhancing Technologies User Group are DLR, APFC devices, TTO, and advanced conductors.

Dynamic Line Rating

DLR systems adjust the thermal limits of transmission lines in real time based on ambient temperature, wind speed, solar radiation, and conductor characteristics. These systems can increase line ratings by 10% to 40% under favorable conditions, reducing congestion and enabling higher utilization of existing infrastructure (INL, 2024b). DLR systems typically rely on tension sensors, LiDAR, or weather stations placed along critical spans. They provide real-time data that feed into centralized analytics platforms, which recalculate ratings every few minutes to account for environmental changes. Forecast-based DLR, which predicts future ratings using weather models, allows for DLR integration in the day-ahead and other forward horizons. Figure 3 (p. 6) illustrates how DLR compares with static (SLR), seasonal (SAR), and ambient-adjusted (AAR) line ratings, demonstrating how DLR more closely tracks real-time conditions and enables higher transmission utilization.

FIGURE 2

Comparison of Advanced Transmission Technologies by Typical Capacity Increase, Cost, and Deployment Time



This figure visualizes the trade-offs among advanced transmission technologies. Grid-enhancing technologies (GETs) offer rapid deployment within months and modest-to-significant capacity increases at a lower cost. In contrast, conventional solutions like greenfield transmission and HVDC conversion offer higher long-term capacity potential but require longer lead times (5–15 years) and significantly higher capital investment. Deployment time is shown as data labels above each bar, while color shading represents relative cost.

Source: White et al. (2024); U.S. Department of Energy.

In response to the Federal Energy Regulatory Commission (FERC) Order 881's mandate for ambient-adjusted rating, utilities are focusing their present efforts on implementing these systems. While ambient-adjusted ratings are variable ratings, DLR refers to the use of additional data beyond ambient temperature to determine more accurate ratings (e.g., wind speed, sag, cloud cover). To fully implement DLR, utility systems may need enhancements to better manage communication requirements and the influx of data. By accurately forecasting conductor temperatures across an entire circuit, DLR technology can provide significantly more information to utilize the system better. This deeper understanding of conductor behavior can, in turn, refine asset health models and improve line clearance calculations, ultimately leading to a more efficient and reliable energy transmission system.

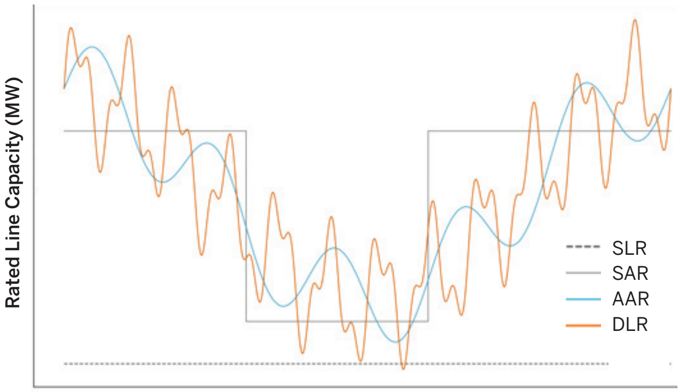
Advanced Power Flow Control Devices

Power flow control technologies enable grid operators to actively manage the flow of power across the transmission network by modifying line impedance or modifying voltage at targeted points. These devices allow power to be rerouted around congested corridors, balancing line loading and enhancing reliability without requiring major infrastructure upgrades. This process is akin to redirecting traffic from congested highway lanes to clearer ones.

Conventional power flow control technologies, such as phase-shifting transformers and series reactors, have been used for decades. More recently, a new class of modular, power electronics–based power flow control devices has emerged. These APFC systems offer compact designs, faster response times, and flexible deployment

FIGURE 3

Illustrative Comparison of Dynamic Line Rating, Ambient-Adjusted Rating, Seasonally Adjusted Rating, and Static Line Rating



Static line rating (SLR) assumes worst-case, least-cooling conditions and provides fixed, conservative capacity limits year-round. Seasonally adjusted rating (SAR) may increase capacity slightly by adjusting limits based on typical seasonal weather conditions. Ambient-adjusted rating (AAR) further improves utilization by incorporating real-time air temperature, typically offering 5% to 10% increases compared with static ratings. Dynamic line rating (DLR) represents the most adaptive approach, accounting for air temperature and other variables such as wind speed and solar conditions to reflect actual conductor conditions—yielding 10–40% or more in additional capacity during favorable conditions.

Source: Energy Systems Integration Group.

(EPRI, 2018). Their modular architecture allows utilities to expand, relocate, or repurpose them as system needs evolve, and installations can often be completed in a matter of hours. For example, a 2016 pilot deployment on the EirGrid system required just five hours to install and energize, highlighting the technology's potential to address near-term system constraints with minimal disruption (Smart Wires + EirGrid, n.d.).

APFC systems are applied across several key operational needs (INL, 2024c):

- Managing congestion as part of economic dispatch
- Mitigation of unscheduled flows
- Preventive contingency management
- Corrective contingency management

In terms of control, APFC devices can operate under centralized, decentralized, or hybrid schemes. Decentralized controllers respond immediately to local conditions, while centralized systems coordinate multiple units using system-wide data—enhancing effectiveness by optimizing the entire system's needs. A hybrid approach enables immediate local response followed by coordinated setpoint adjustments aligned with broader grid objectives.

APFC devices' dynamic characteristics make them well suited for areas with high levels of variable energy sources or limited siting flexibility. These devices can dynamically control power flows by injecting voltage in series or altering line impedance and redirecting electricity from overloaded to underutilized circuits, thus alleviating congestion, reducing losses, and supporting system stability.

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Transmission Topology Optimization

TTO identifies beneficial transmission switching opportunities—the strategic opening or closing of breakers and switches to reconfigure the electrical pathways of the transmission network. These reconfigurations can relieve congestion, improve voltage profiles, reduce system losses, and adapt flows to changing grid conditions without requiring new infrastructure.

Modern transmission systems are designed with redundancy to ensure reliable operation under various system conditions and contingencies. TTO tools capitalize on this latent flexibility by treating the network as a controllable asset. By identifying beneficial switching actions, operators can dynamically shift power flows to underutilized lines, enhance dispatch efficiency, and alleviate constraints (INL, 2024d). These actions are designed to remain within thermal, voltage, and stability limits.

TTO uses advanced optimization algorithms to determine system-wide switching configurations that support

economic scheduling, improve outage coordination, and unlock seasonal switching opportunities. Optimization techniques vary across tools—from heuristic approaches grounded in power systems modeling and mathematical optimization to machine learning models trained on historical system data. Yet others explore feasible topological reconfigurations through exhaustive search methods.

When paired with generation commitment and dispatch, TTO allows planners and operators to implement low-cost, reliable grid configurations that improve operational flexibility.

Applications span multiple planning and operations time frames (Ruiz and Myhre, 2024):

- **Real time and intra-day:** Adapt to emergency conditions, relieve N-1 flow violations, minimize real-time congestion and manual unit starts, unlock export capacity, and reduce curtailments
- **Day ahead:** Pre-position system topology to match forecasts and reduce day-ahead congestion costs
- **Weeks ahead:** Support outage scheduling, mitigate outage-related congestion, and enable operational guides for extreme events
- **Long-term planning:** Optimize the transmission expansion portfolio and maximize the benefit-to-cost ratio of new infrastructure

TTO is already in active use across regional grids, with MISO and the Electric Reliability Council of Texas (ERCOT) deploying switching strategies that have saved tens of millions of dollars in congestion costs and proven the operational value of reconfiguration. These results demonstrate that TTO is not just a theoretical planning tool—it is a practical, low-disruption strategy already embedded in modern grid operations.

Advanced Conductors

Advanced conductors are overhead transmission wires designed to carry more current at higher operating temperatures. These technologies are typically used to upgrade existing transmission lines by replacing conventional conductors—such as aluminum conductor steel-reinforced (ACSR)—without requiring new towers or rights-of-way. Their core advantage is enabling capacity increases while preserving or even improving clearances and thermal limits.

While there is no single industry-wide definition of “advanced conductor,” FERC Order 2023-A defines the term as encompassing technologies that are advanced relative to conventional ACSR designs.[2] This report focuses primarily on the most commonly deployed technologies in current utility planning and upgrades, including:

- High-temperature low-sag conductors, such as ACSS with high-strength steel alloys
- Composite-core designs, like ACCC (aluminum conductor composite core), ACCR (aluminum conductor composite reinforced), and AECC (aluminum encapsulated carbon core)
- Conductors with heat-dissipating coatings to improve ampacity and efficiency

Most advanced conductors can operate continuously at 150 to 200˚C, well above the ~93˚C limit of ACSR, with many rated for even higher temperatures under emergency conditions. ACSS conductors are designed for continuous operation up to 250˚C. Composite-core conductors offer high strength-to-weight ratios and significantly reduced sag at high current, allowing reconductoring with minimal or no tower modifications.

In practice, reconductoring with advanced conductors can increase line capacity by 25% to 100%, depending on conductor type and system limitations. Some utilities report capacity doubling on thermally constrained lines. However, the full benefit depends on whether the line is thermally limited. For longer or higher-voltage lines, system constraints, such as voltage drop, stability, or protection settings, may limit usable capacity gains. Figure 4 (p. 9) compares ACSR against other key conductor types.

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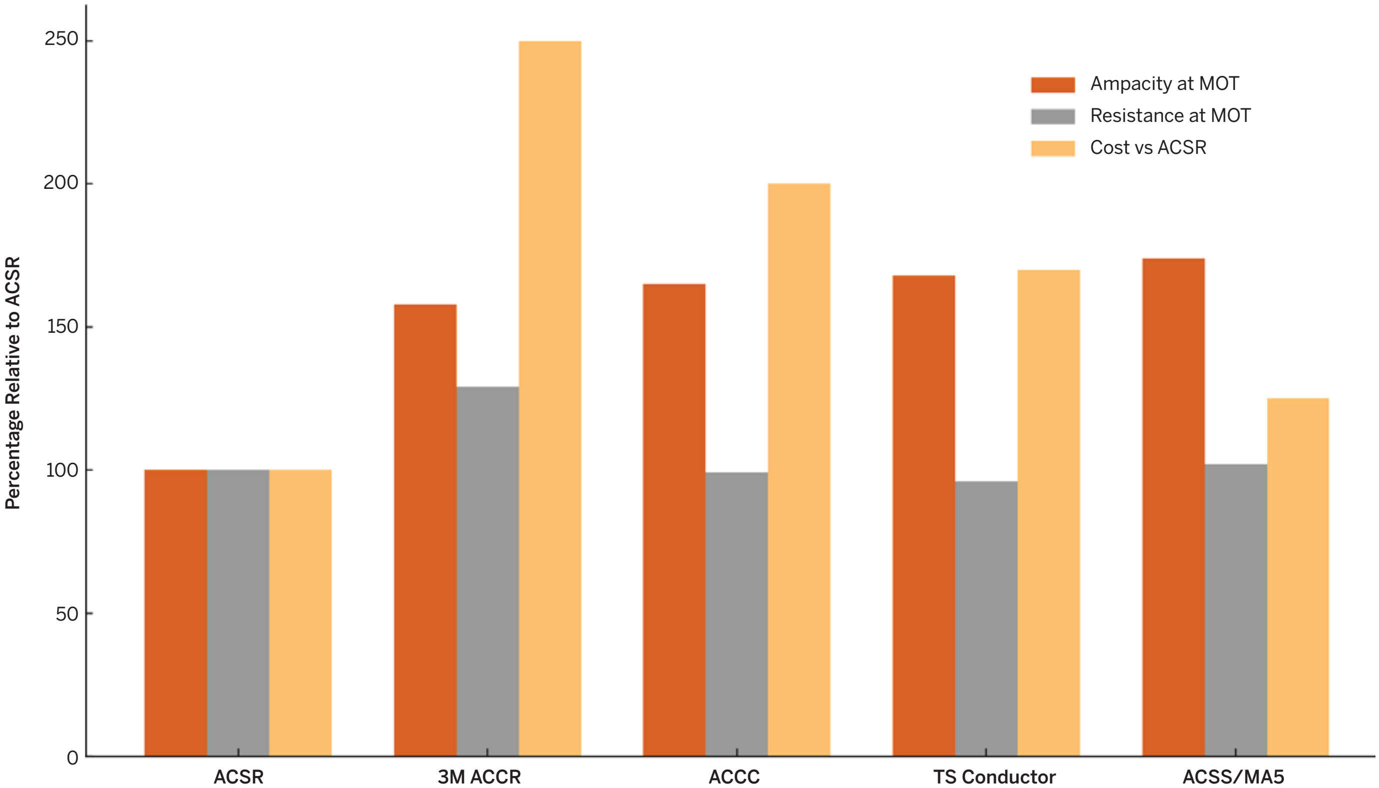
2 https://www.federalregister.gov/documents/2024/04/16/2024-06563/improvements-to-generator-interconnection-procedures-and-agreements

FIGURE 4

Key Conductor Types Compared Against ACSR



Key conductor types are compared against ACSR in terms of ampacity at maximum operating temperature, resistance at 20°C, and cost.

Notes: ACCC = aluminum conductor composite core; ACCR = aluminum conductor composite reinforced; ACSR = aluminum conductor steel-reinforced; MOT = maximum operating temperature.

Source: Idaho National Laboratory (2024a).

Although advanced conductors are more expensive per mile than traditional ACSR, the conductor cost is often less than 5% of the total project cost—and far less than the cost of building new lines. In many cases, reconductoring offers the lowest-cost and fastest option to address capacity shortfalls, especially where permitting, siting, or outage constraints preclude full rebuilds.

The *Advanced Conductor Scan Report*, published by INL with support from the U.S. Department of Energy, offers a thorough analysis of advanced conductors (INL, 2024a). It details their design, performance benefits, and potential to improve the capacity, efficiency, and resilience of the electrical grid. The report examines various advanced conductor technologies, their real-world applications, and the challenges associated with their adoption, emphasizing the importance of these conductors in modernizing transmission infrastructure.

Most of these conductors have been commercially available for several years, and manufacturers provide specifications for installation, inspection, maintenance, and performance. However, standardized third-party testing protocols that apply consistently across manufacturers and conductor types are still evolving. Deployments of these conductors over the last 15 years have provided considerable experience; however, further research on the installation and long-term performance, inspection, and assessment after a critical mass of conductors is deployed can increase confidence in this valuable technology.

Initiatives Advancing and Deploying GETs

State and federal efforts have been actively supporting GETs—i.e., advanced transmission technologies—to improve grid performance and reliability. Key initiatives include FERC Orders 2023 and 1920, which require the inclusion of advanced technologies in transmission planning. FERC Order 881 and its associated docket on DLR also focus on the required use of ambient-adjusted rating and potentially DLR. States are also promoting GETs through mandates, incentives, and performance criteria. These actions aim to modernize the grid cost-effectively and enhance energy infrastructure by encouraging the use of all available technologies.

FERC Orders

FERC Order 881, issued in 2021, requires a transition from static transmission line rating to ambient-adjusted ratings for near-term transmission service requests (ending within 10 days) and seasonal ratings for longer-term service requests.[3] It also mandates the development of systems that enable transmission providers to electronically update transmission line ratings at least once per hour, along with unique emergency ratings, and enhances transparency. While DLR is not required, FERC acknowledged its benefits and indicated that future rulemaking may expand the role of DLR in transmission planning and operations.

FERC Order 2023, issued to enhance generator interconnection, mandates that transmission providers assess a list of alternative transmission technologies (ATTs) in interconnection studies.[4] However, the final rule excluded DLR, stating that since its benefits depend on favorable weather conditions, it may not guarantee reliable interconnection service across all hours, unlike traditional upgrades.

FERC Order 1920 was issued in May 2024 and aims to update long-term regional transmission planning significantly.[5] It mandates the consideration of specific advanced technologies—DLR, APFC, advanced conductors, and transmission switching—in planning studies. Transmission providers must apply uniform criteria to evaluate these technologies and justify their selection or non-selection for each project, aiming to accelerate adoption and improve grid performance.

The FERC Advance Notice of Proposed Rulemaking (ANOPR) 2024 aims to expand the use of DLR by requiring transmission providers to consider real-time variables such as solar heating and wind speed—especially on congested lines.[6] The ANOPR introduces congestion-based metrics to identify candidate lines for the deployment of DLR and proposes broader transparency requirements, including data on service denials and congestion costs. These reforms build on Order 881 and signal FERC's intent to more directly integrate DLR into transmission planning and operations.

State Legislative Policies

States are implementing various policies to promote the deployment of GETs and high-performance conductors, including regulatory mandates, planning requirements,

3 https://www.federalregister.gov/documents/2022/05/25/2022-11233/managing-transmission-line-ratings

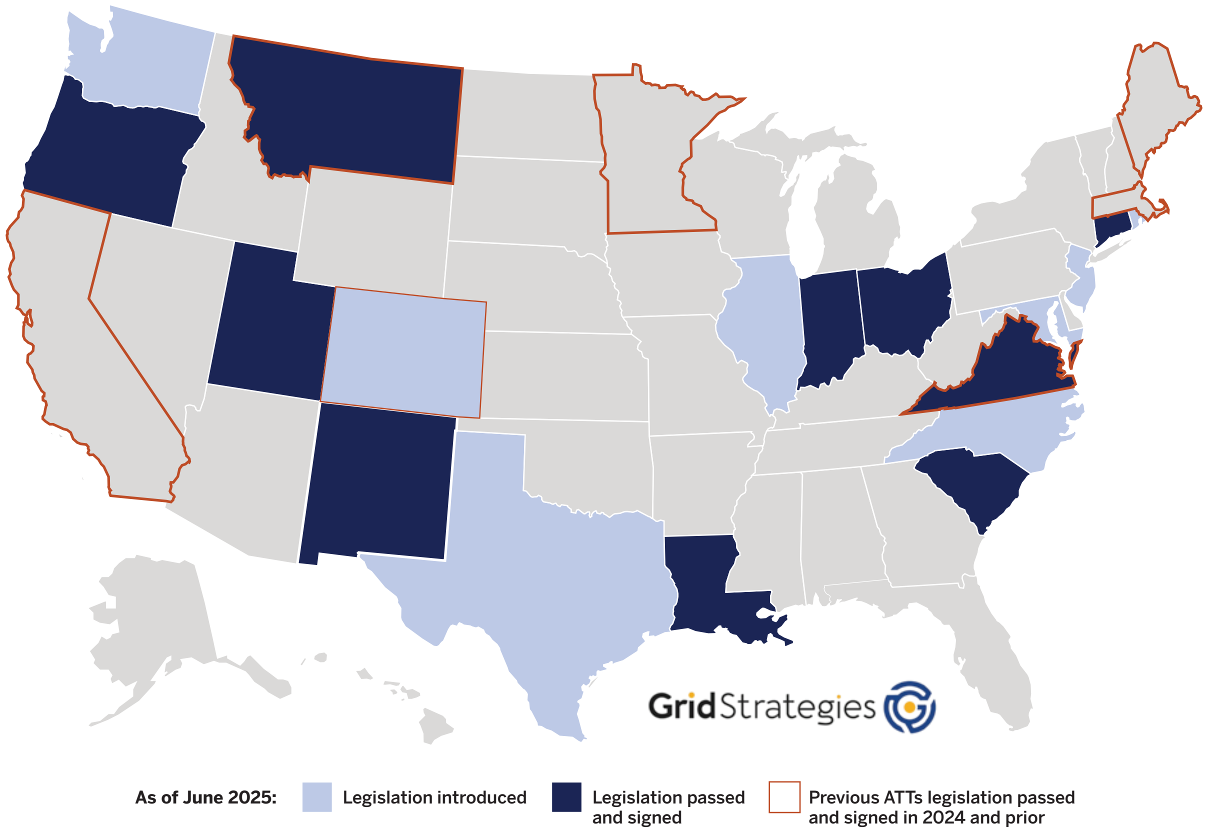
4 https://www.ferc.gov/media/order-no-2023

5 https://www.ferc.gov/explainer-transmission-planning-and-cost-allocation-final-rule#_Key_Decisions_of

6 https://www.ferc.gov/news-events/news/ferc-seeks-comment-potential-dlr-framework-improve-grid-operations-fact-sheet

FIGURE 5

State Action on Grid-Enhancing Technologies as of June 2025



States are implementing a range of policies to promote GETs and advanced conductors. This map shows states that are developing or have passed legislation requiring or encouraging their use in transmission planning.

Source: Grid Strategies.

financial incentives, and implementation guidance (Figure 5) (see also ACEG (2024)).

These initiatives reflect an increasing interest in using advanced technologies to alleviate congestion, defer infrastructure upgrades, and modernize the grid by:

- **Defining technical performance.** Some states are establishing clear technical criteria to guide utility decision-making. For example, in 2023, Montana passed a law defining "advanced conductor" based on a minimum 10% reduction in DC resistance compared to standard conductors of the same diameter and requiring cost-effectiveness evaluations to use consistent reference conditions (e.g., temperature, pressure).[7]
- **Requiring evaluation in utility planning.** States including Virginia and California now require utilities to evaluate GETs and high-performance conductors in formal planning processes. Virginia mandates the assessment of these technologies in integrated resource plans,[8] while California's SB 1006 requires biennial studies on GETs and quadrennial surveys to identify transmission lines suitable for reconductoring with advanced conductors, with results submitted to the California Independent System Operator and made public.[9] Some states also incorporate GETs

7 See Montana Code § 69-3-714.69-3-714. Criteria for allowable advanced conductor programs, MCA

8 See Section B.10 of § 56-599. Integrated resource plan required

9 Bill Text - SB-1006 Electricity: transmission capacity: reconductoring and grid-enhancing technologies.

evaluation into transmission siting or Certificate of Public Convenience and Necessity (CPCN) proceedings.

- **Directing state commissions to study GETs.** In some cases, state utility commissions—not utilities—are taking the lead. For example, Maine enacted a law requiring its Public Utilities Commission to conduct a review every five years of GETs that could be used to defer or reduce transmission investment.[10]
- **Offering financial incentives.** Some states are exploring or piloting performance-based incentives to encourage utilities to adopt GETs. A recent New York legislative proposal (not passed) would have allowed utilities to earn a return-on-equity adder for GETs investments deemed more cost-effective than conventional solutions to network congestion.
- **Authorizing cost recovery and capital planning.** While states generally allow cost recovery for infrastructure investments, some state utility commissions may be hesitant to direct their utilities to incorporate GETs and high-performance conductors into their capital improvement plans and/or to allow cost recovery for GETs and high-performance conductor projects without express authorization and encouragement from their legislatures. Some states, however, have made it explicit that utilities can treat GETs investments as eligible capital expenditures. In Minnesota, a 2024 law requires large transmission owners to file biennial evaluations of GETs to address system congestion, proposes implementation plans, and authorizes full cost recovery, including a regulated return, for approved GETs deployment.[11]
- **Streamlining permitting requirements.** A few states are also considering permitting exemptions or streamlined reviews for advanced reconductoring projects. In these cases, utilities may be allowed to proceed through less burdensome “advice letter” filings rather than full permitting processes, thus reducing delays and regulatory friction.

Utilities’ Use of Different GETs

While FERC and state actions are beginning to create clearer signals and incentives for GET adoption, implementation ultimately depends on decisions made by utilities themselves. The following section highlights how utilities across the country are deploying different GETs to address capacity needs, improve reliability, and accelerate grid upgrades.

Dynamic Line Rating

Several utilities, including AES (AES, 2024a), Idaho Power, and PPL Electric, have piloted or deployed DLR to increase transmission line ratings during favorable weather conditions. DLR enables operators to dynamically adjust thermal ratings based on real-time wind and temperature data, providing a low-cost, no-outage alternative to reconductoring or rebuilding.

As noted above, PPL Electric installed DLR on three transmission lines, achieving a 15% to 17% capacity increase and realizing $64 million in congestion cost savings in the first year of operation (Gentle et al., 2024). The utility’s internal business case found that DLR could be deployed within a year, with no outages, at a cost of less than $1 million, and provide estimated capacity gains of 10% to 30% (PPL, 2022). PPL was also the first U.S. utility to use DLR in both real-time operations and market participation (PPL, 2023).

Idaho Power is accelerating the installation of DLR systems using drones as part of the U.S. Department of Energy’s investment in GETs, which aims to increase the use and reliability of existing transmission lines (Idaho Power, 2025).

10 Bill Text S.P. 257–L.D. 589: An Act to Ensure That the Maine Electric Grid Provides Additional Benefits to Maine Ratepayers

11 Bill Text HF5247, Artcile 42 : Energy Policy. Sec.21 and Sec. 52

Several other utilities have also noted the operational benefits of DLR in managing fluctuating energy flows from variable energy sources. Through a pilot on the Cook–Olive 345 kV line, AEP demonstrated that DLR can significantly decrease congestion costs and offer operational flexibility during peak conditions. Similarly, a Great River Energy pilot project showed a 42.8% average increase in transmission capacity on a key line and is now expanding the deployment (Heimdall Power and GRE, 2024). The New York Power Authority observed a 20% increase in transfer capacity and a reduction in wind curtailment using DLR systems supported by machine learning (INL, 2024b). Other utilities—including Duquesne Light Company and Oncor Electric Delivery—are also evaluating or scaling DLR as part of broader grid modernization strategies (Abboud et al., 2022).

Power Flow Control Devices

In the UK, National Grid deployed modular power flow control devices across three substations to manage five circuits (National Grid, 2021b). This effort unlocked an additional 1.5 GW of generation capacity and delivered an estimated £400 million in savings over seven years, due to reduced constraint costs and lower project expenses compared to conventional reinforcements, such as reconductoring lines or replacing transformers (National Grid, 2021a; Smart Wires, 2025). Central Hudson Gas & Electric recently piloted static synchronous series compensators to facilitate the integration of additional generation resources on a constrained interface identified through the New York Independent System Operator generator interconnection study (Renewable Energy World, 2024). The static synchronous series compensators were considered an alternative to traditional series compensation, which could have adversely impacted existing protection schemes.

Advanced Conductors

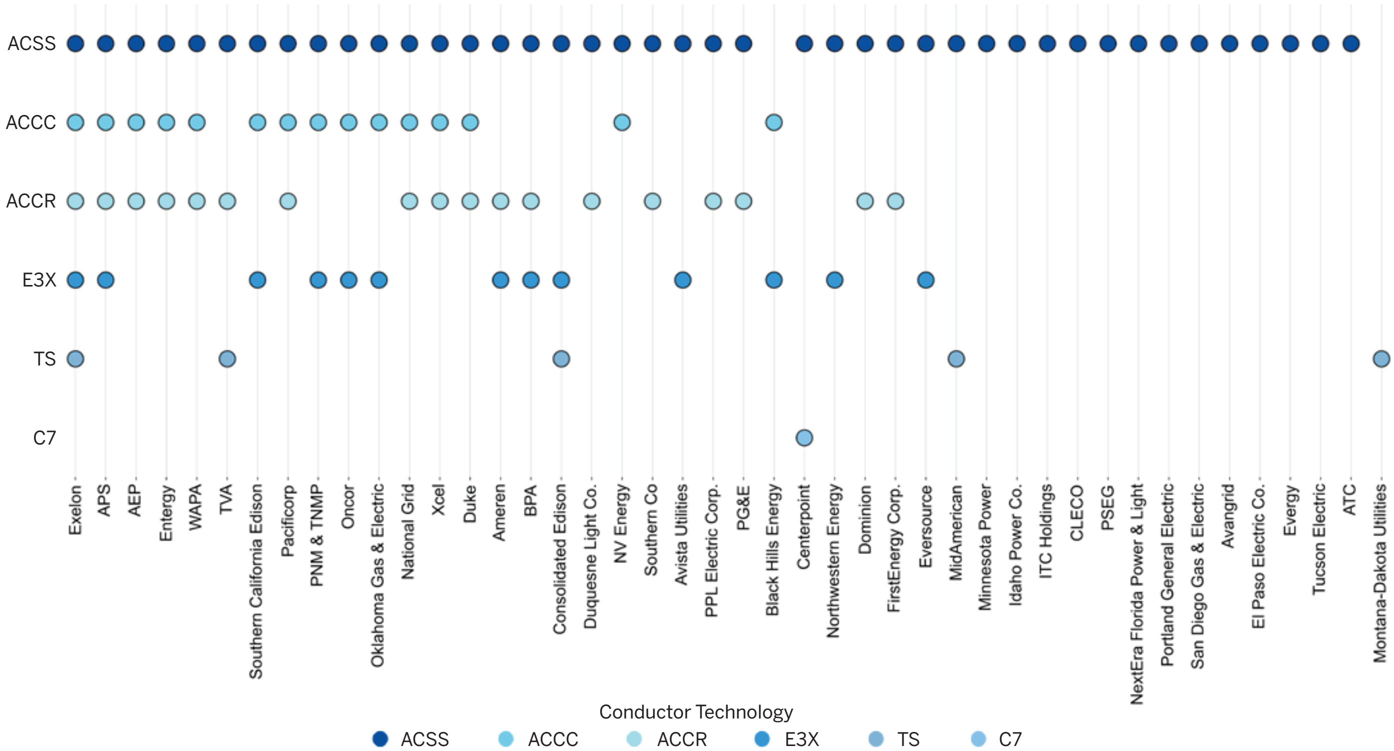
Advanced conductors have proven to be a reliable solution for increasing transmission capacity without expanding rights-of-way or incurring lengthy permitting timelines. Reports from INL (INL, 2024a) and the DOE's Pathways to Commercial Liftoff initiative document dozens of utility projects that demonstrate increased ampacity, reduced sag, and improved line performance under thermal stress.[12] The INL report presents a broad collection of case studies demonstrating how advanced conductors can effectively boost capacity, minimize losses, and improve resilience, especially in challenging scenarios. It highlights the positive experiences of over 40 utilities, including AEP, Southern California Edison, and Dominion Energy, which have successfully used these conductors to enhance transmission capacity without requiring new rights-of-way. Figure 6 (p. 14) summarizes the deployment of specific advanced conductor technologies —such as ACCC, ACSS, and ACCR—by each profiled utility, illustrating the diversity of solutions and the breadth of adoption across the industry.

In 2016, AEP reconductored two 120-mile, 345 kV lines in Texas using composite core conductors, increasing capacity by 40% without de-energizing the lines (Energy Biz, 2016). Southern California Edison has installed more than 385 miles of composite conductors and plans to reconductor 300 to 400 additional miles to accommodate growing load and renewable generation (Driscoll, 2024). Duke Energy is reconstructing the Lee–Milburnie 230 kV line with high-temperature low-sag conductors to support over 1,800 MW of new solar and storage capacity (GDO, 2024). Ameren upgraded 375 miles of 345 kV corridor using ACSS in Illinois, while Evergy's

12 https://www.energy.gov/lpo/pathways-commercial-liftoff-reports

FIGURE 6

Advanced Conductor Deployments by U.S. Utilities



Utilities across the U.S. are deploying advanced conductors. This figure shows the adoption of six advanced conductor technologies —ACSS (aluminum conductor steel-supported), ACCC (aluminum conductor composite core), ACCR (aluminum conductor composite reinforced), E3X, TS, and C7—across more than 40 U.S. utilities, based on reported project deployments. It highlights both the widespread use of composite-core conductors like ACCC and the diversity of technologies being implemented.

Source: Adapted from INL *Advanced Conductors Scan Report* (INL, 2024a).

32-mile reconductoring project paid for itself within 14 months through congestion savings.

Other large-scale deployments include ATC's 180-mile system upgrade, using advanced conductor blends, and Oncor's 850-mile ACSS/TW (trapezoidal wire) installation under the competitive renewable energy zone (CREZ) initiative to expand renewable energy delivery in Texas. Xcel Energy and National Grid have used advanced conductors to improve clearance, limit structural rebuilds, and upgrade aging infrastructure to support grid modernization goals (INL, 2024a).

These examples reflect a growing consensus that advanced conductors are reliable and repeatable options for enhancing capacity and flexibility in both rural and urban transmission environments.

Grid Automation, Switching, and TTO

MISO has implemented a TTO process that allows market participants to propose reconfigurations to address congestion. These proposals are jointly evaluated with transmission owners and, when they provide value while continuing to support system reliability, can be implemented promptly. In 2024 alone, MISO saved at least $24 million from reconfigurations tied to major outages and market-to-market constraints (MISO, 2024). Since 2021, Alliant Energy's use of reconfiguration has saved its customers over $30 million (ITC Midwest, 2025). MISO's Independent Market Monitor has recommended expanding the use of this tool to reduce congestion and lower costs (Potomac Economics, 2022).

MISO Reconfiguration Process

Launched in 2023, MISO's reconfiguration process allows both MISO and market participants to request the evaluation and implementation of reconfiguration to relieve congestion. Each reconfiguration request is reviewed for technical and economic feasibility before implementation. The process falls within the operations planning time frame and formalizes how market participants can submit reconfiguration proposals—broadening its use beyond internal-only analysis—as well as how such proposals are evaluated by MISO and the affected transmission owners.

In SPP, a similar process continues to be developed that will enable market participants to request evaluations of specific transmission operation actions aimed at mitigating congestion (SPP, 2025).

ERCOT's Extended Action Plan Revisions

ERCOT recently approved two key revisions to its market and operational rules—Nodal Protocol Revision Request 1198 and Operating Guide Revision Request 258—that expand the use of topology reconfiguration to manage congestion. These changes define Extended Action Plans as a formal type of Constraint Management Plan and remove the prior restriction limiting their use to scenarios without feasible Security-Constrained Economic Dispatch solutions. Extended Action Plans can now be applied more broadly, even when Security-Constrained Economic Dispatch solutions are available.

The revisions also establish a clear submission and approval process, apply economic and reliability guardrails, and align Extended Action Plans with ERCOT's existing operational planning. The result is a scalable and transparent framework that treats topology reconfiguration not as an exception, but as a routine tool for improving dispatch efficiency and managing congestion.

What Users of GETs Are Sharing

During 2024, the ESIG GETs User Group had several discussions and surveyed its members to explore the applications, challenges, solutions, and prospects for GETs. In addition, in public forums and FERC proceedings utilities and grid operators have shared their perspectives and experiences, highlighting both the potential advantages of GETs and the need for careful and coordinated adoption. Many of the user group participants recognize the value of these technologies and encourage a thorough analysis to evaluate their benefits and risks before widespread implementation.

Support for GETs

Several utilities and system operators have expressed their support for GETs in public forums, emphasizing the importance of these technologies in modernizing the electricity grid. Many utilities and operators see GETs as essential interim solutions while making long-term investments, enabling them to maximize the potential of existing infrastructure. Some GETs are increasingly considered long-term investments—this applies particularly to advanced conductors—and others can also support efficiency on both existing networks and future expanded networks.

Overall, grid operators are supportive of GETs, and many are actively exploring ways to integrate these technologies into their systems. User group participants discussed the benefits they see in GETs.

Reliability and Resilience

GETs can improve resilience, observability, operational flexibility, and reliability by providing better control over power flows and reducing the impact of outages. In addition, GETs enhance the grid's ability to anticipate, withstand, and recover from disruptions by providing real-time data and fast control mechanisms that support proactive management and rapid response to issues. AFPC and TTO can provide corrective control during contingencies, enabling the quick management of flows and restoring the system to a secure state, potentially without the need for generator redispatch. Further, by providing operators with granular, real-time data, GETs can improve situational awareness.

Increased Transfer Capacity

GETs boost the capacity of existing transmission lines, enabling operators to transfer more power without requiring new infrastructure. By improving system visibility and control, GETs unlock short-term capacity gains that can be deployed while long-term upgrades are still in development. Each GET increases network flow in different ways—whether through real-time ratings, power flow redirection, or conductor upgrades—enabling more efficient use of existing assets and helping reduce operational costs.

Cost Savings

Implementing GETs can lead to significant cost savings for utilities and consumers. GETs optimize grid operations and reduce operational expenses, including congestion costs, energy prices, and maintenance costs. This translates to lower electricity costs for consumers.

- **Lower operational costs:** By optimizing the use of current assets, utilities can reduce their operational costs.
- **Deferral of transmission upgrades:** GETs can be deployed faster than, and defer the cost of, traditional upgrades.

- **Extended asset lifespan:** GETs can help extend the lifespan of existing grid infrastructure, delaying the need for replacements.
- **Lower energy prices:** GETs can help lower consumer energy prices by increasing grid efficiency and reducing congestion.

Quick Deployment

GETs can be installed and be operational quickly, allowing utilities to address grid challenges swiftly and cost-effectively. DLR, APFC, and TTO can be installed in a matter of months. Reconductoring using advanced conductors can also increase the capacity of a transmission path much faster than acquiring new or increased right-of-way to get higher flows. This can enable increased capacity to improve economic efficiency or correct specific acute network issues without the uncertainty associated with long lead times.

GETs can be installed and be operational quickly, allowing utilities to address grid challenges swiftly and cost-effectively. DLR, APFC, and TTO can be installed in a matter of months.

Supporting the Integration of Emerging Technologies

GETs can support the integration of energy sources like solar, wind, and battery storage by improving the grid's ability to handle variable power flows. Network flows may become less predictable as variable energy resources increase, resulting in very different congestion patterns at various times of day. By increasing grid flexibility, increasing capacity, and facilitating the redirecting of flows, GETs can enable greater integration of these technologies. GETs can also support the integration of new loads, including those resulting from electrification and large load interconnection, by managing any changing flow conditions that may require mitigation.

Reducing the Interconnection Queue Backlog

By increasing the capacity of existing transmission lines, GETs allow more projects to connect to the grid without costly and time-consuming upgrades. This can help reduce the backlog in interconnection queues.

Supporting Supply Adequacy

By enabling faster integration of new energy generation sources, GETs can help ensure a reliable, adequate, and secure power supply.

DLR, APFC, and TTO have modular capabilities and can be applied incrementally. This flexibility allows utilities to adjust optimal placements in response to changing conditions and the introduction of new transmission and generation assets.

Scalability and Flexibility

Certain GETs, including DLR, APFC, and TTO, provide modular capabilities that can be applied incrementally. This flexibility allows utilities to adjust optimal placements in response to changing conditions and the introduction of new transmission and generation assets. These technologies can thus be a cost-effective, least-regrets solution for addressing both immediate and long-term challenges.

Barriers to Broader Adoption of GETs

While GETs offer clear operational benefits—helping reduce interconnection backlogs and provide flexible deployment options—their adoption has not yet become routine. Many utilities still face institutional, technical, and regulatory obstacles that slow or prevent deployment. This section outlines the key barriers that continue to limit broader adoption.

Cautionary Perspectives on GETs in Long-Term Planning

While GETs such as DLR, APFC, and TTO offer clear value in improving grid flexibility, relieving congestion, and optimizing existing infrastructure in the near term, many utilities, system operators, and planning stakeholders have expressed caution about their suitability for long-term transmission planning. These technologies have been described by some user group participants as too uncertain, too operationally specific, or having too short a track record to be relied upon in the multi-year investment studies that underpin grid expansion, cost allocation, and reliability compliance. The participants said that the dynamic and condition-based nature of many GETs makes it challenging to integrate with the deterministic assumptions commonly used in long-term transmission models.

Uncertainty in Performance, Forecasting, and Modeling

One of the central challenges in applying GETs to long-term transmission planning is that many of these tools rely on variable inputs and uncertain operating conditions that are difficult to forecast or control over multi-year time frames. This reliance on real-time system dynamics makes it difficult to apply the deterministic assumptions that have typically underpinned long-term infrastructure investment and reliability planning.

DLR, for example, adjusts line ratings based on changing ambient conditions. While DLR has shown operational value in real time, planners note that these environmental inputs are highly variable and difficult to predict reliably into the future—whether it be months or years. In a long-term planning context, relying on favorable ambient conditions could result in overly optimistic assumptions about available network capacity. If weather-based ratings are used without conservative margins, it is argued, planners may underestimate capacity needs—particularly under system stress or extreme conditions—leading to underbuilt infrastructure and increased risk to reliability.

Similarly, technologies like APFC and TTO respond dynamically to real-time dispatch, topology, and control settings. Their effectiveness depends on system conditions that change frequently and may not be easily represented in long-term models. In particular, the wide range of possible configurations these tools introduce—especially under future system scenarios with new generation, evolving load patterns, and changing dispatch—makes it impractical to pre-study all potential system states. Planners have cautioned that this creates a modeling blind spot that is difficult to reconcile with current planning tools and frameworks.

In contrast, hardware-based technologies with fixed physical characteristics, such as advanced conductors, do not rely on real-time inputs or control schemes. However, they can raise concerns about long-term degradation rates, asset life, and performance under stress. Many are still relatively new to the transmission system and lack the long-term field data and asset management standards that planners typically require when modeling system upgrades 20 or 30 years into the future.

Alignment with Reliability Compliance and Operations

Planners have also raised concerns about how GETs fit within the requirements of compliance-driven planning processes. Studies conducted to meet requirements, such as NERC's Transmission Planning Standard TPL-001, typically depend on firm and conservative assumptions about system behavior and asset performance. The conditional nature of some GETs (e.g., DLR's real-time adjustment) and the modeling complexity they introduce could either complicate compliance or lead to planning decisions that fail to meet reliability obligations.

Even when the potential benefits of GETs are acknowledged, their conditional nature can put planners in a difficult position: either apply highly conservative derating that negates much of the value or accept modeling

assumptions that may not hold up under regulatory scrutiny. In either case, the ability to use GETs as substitutes for traditional infrastructure can be constrained.

Importantly, the uncertainty between what is modeled in long-term planning and what occurs in real-time operations is not new. However, some stakeholders have suggested that GETs—by depending more heavily on variable inputs, dynamic controls, and adaptive system behavior—may widen the existing gap between planned and actual system conditions. Until modeling methods, operational data, and performance standards for GETs mature, planners suggest that these tools are best applied to operational or near-term decision-making rather than as firm capacity assumptions in long-term studies.

Limitations of Planning Modeling Tools and Data Integration

Planners and operators have noted that many long-term transmission planning tools are traditionally designed to assess steady-state conditions, using fixed system assumptions and a limited number of representative scenarios. These methods work well for evaluating large, static infrastructure over long time horizons, but are not always well suited to simulating technologies that respond dynamically to real-time conditions, such as DLR, APFC, and TTO. Even for hardware-based upgrades, such as advanced conductors, planners noted that modeling sag, clearance, or thermal performance may require span-level data that are not readily available in standard tools.

They explain that a key challenge is that these technologies often require modeling at a much finer temporal resolution (e.g., hourly or sub-hourly variation in weather or dispatch) and across a wider range of geographical system configurations (e.g., how flows shift under different topologies, regional dispatch patterns, or load conditions). Existing planning tools typically rely on a limited number of fixed "snapshot" scenarios, which may not capture the full range of system behavior necessary to evaluate GETs.

Additionally, power flow and production cost models used in long-term planning may lack built-in capabilities to simulate these technologies, requiring custom inputs or manual workarounds. This can make it challenging to apply GETs consistently across studies or compare them directly with traditional infrastructure options.

While modeling capabilities are improving, and some planners are beginning to include GETs in scenario analyses or pilot studies, these technologies are not yet fully integrated into standard long-term planning workflows. For now, GETs are often viewed as better suited for operational or near-term studies, with broader planning applications expected to expand as tools, data, and methodologies continue to mature.

Concern About the Prospect of a Universal Mandate to Include GETs in All Transmission Planning

In addition to concerns about technology, utilities are concerned about the proposed imposition of a universal mandate, either at the state or federal level, that would force utilities to apply these technologies across all transmission projects, regardless of their unique regional needs. They assert that the requirement to consider study-specific solutions could impose unnecessary costs and complexity on regions where the benefits of GETs would be marginal. Additionally, the requirement to evaluate GETs for every potential project could add unnecessary costs and complexity to the planning process, diverting focus from other critical needs. Utilities and system operators believe that introducing rigid mandates would burden transmission providers with additional administrative requirements and limit their ability to explore and implement other innovative solutions tailored to local grid conditions. The concern is that mandatory GETs evaluations could become a "check-the-box" exercise, potentially delaying projects that may already address more urgent reliability concerns.

Concern About the Possibility That GETs Could Undermine System Stability

Planners and operators have raised concerns that some GETs—particularly those that automate or influence power flow and grid topology—may introduce system conditions that fall outside the scope of traditional contingency and stability assessments. While the intent of these technologies is to optimize grid usage and increase flexibility, their ability to change power flow patterns in real time introduces a large number of potential operating states that may not be fully captured in either near-term or long-term planning studies.

This point is amplified when such tools are deployed at scale or on high-voltage, backbone facilities. In these cases, the number of possible grid configurations increases significantly, making it impractical to model and validate every scenario in advance—particularly in planning frameworks that prioritize conservative, well-characterized assumptions. Some stakeholders have warned that automatic or semi-automatic adjustments made by GETs, if not properly calibrated and stress-tested, could result in unexpected interactions or operating states that challenge the system's reliability. Modeling and validating every scenario in advance may be impractical.

There is also concern that in real-time operations, previously unstudied flow patterns could emerge under contingency conditions, potentially reducing operator situational awareness or increasing the risk of instability. Additionally, these technologies may interact with existing protection schemes in ways that affect fault detection and isolation (AES, 2024b). Without clear visibility into all the possible outcomes and interactions that these technologies might create—and without robust simulation frameworks and detailed studies to evaluate them—some planners and operators remain cautious about integrating GETs-driven flow control into operations and planning.

Broader Market Implications

The market implications of implementing GETs should also not be overlooked. While optimization models using GETs can reduce overall production costs, they may also shift prices across the network, lowering prices in some areas while raising them in others. This means that even if total societal benefits increase, the impacts may not be evenly distributed, creating both winners and losers. Accurate modeling and forecasting within existing market frameworks can be challenging, introducing uncertainties that may further affect market dynamics and necessitate enhancements. The impact on locational prices can also impact the ability of companies to hedge against volatility. For example, although TTO leads to substantial societal benefit through reduced operational cost in practice, its dynamic configurations are challenging to account for in FTR auctions and may therefore theoretically contribute to underfunding FTRs that are owed to holders. Additionally, continuously evaluating network topology in larger systems can be computationally intensive when integrated with the market-clearing software, which can impact the solve time of the markets.

Almost every change to existing operational and planning practices regarding the grid has implications for system reliability and/or economics. The prudent approach to evaluate and incorporate GETs into current assessments and operating practices needs to ensure that net consumer benefits are realized.

Concern About GETs' Relatively Short Track Record

Planners and operators have noted that many GETs lack the long-term operational track record typically expected for system-critical infrastructure. Unlike conventional transmission assets, which benefit from decades of standardized engineering practices and field data, GETs are still in the early stages of industry-wide adoption. As a result, standard specifications, lifecycle expectations, and performance benchmarks are still being established.

While these technologies have shown promising results in specific applications, stakeholders remain cautious due to the limited operational history and the ongoing development of shared standards for performance, maintenance, long-term reliability, and end-of-life planning.

Uncertainty Around Installation, Longevity, and Maintenance

Utilities and operators have identified a range of practical challenges associated with the installation, longevity, and maintenance of GETs. While many of these technologies show clear promise, stakeholders have emphasized that successful deployment requires more than just technical capability—it also depends on workforce readiness, supply chain resilience, and long-term asset management.

Some advanced conductors, for example, are more prone to fracturing during handling and installation than traditional conductors—and these fractures can be undetectable with standard x-ray inspection methods. Other technologies may require specialized equipment or installation practices that are not yet standard across the industry. The learning curve for field crews and system operators can be steep, particularly when integrating new control systems or monitoring platforms.

In terms of supply chains, while some technologies, such as DLR, are supported by multiple vendors, others have limited manufacturer options, and some key suppliers are based outside the United States. This can complicate procurement and support, especially for utilities seeking long-term contracts or domestic sourcing.

Challenges to the Deployment of GETs

While much of the discussion around GETs focuses on their inclusion in long-term transmission planning, ESIG's GETs User Group also highlighted the distinct challenges that arise during deployment. Even when GETs are acknowledged as viable in studies or planning exercises, utilities face additional barriers when moving toward implementation. These include limited internal familiarity with GET applications, uncertainty around operational integration and reliability, and ambiguity in regulatory treatment and cost recovery.

Cybersecurity

GETs may introduce new cybersecurity risks, particularly when field devices operate outside traditional utility security perimeters or rely on third-party communications and cloud-based platforms. DLR systems illustrate this challenge: sensors may transmit real-time line and weather data over public or commercial networks, creating new points of exposure in the utility's control environment.

Because these systems often operate outside traditional security perimeters, they may not neatly align with existing North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) frameworks. Utilities deploying DLR have flagged and addressed potential issues with data integrity, access control, and compliance tracking, particularly when using externally hosted platforms or vendor-managed services.

A recent report from INL provides a valuable overview of these risks and how they intersect with existing regulatory frameworks. It highlights key concerns around data integrity, access control, and CIP compliance—especially when DLR systems are integrated into SCADA (supervisory control and data acquisition) or EMS (energy management system) platforms using externally managed services (INL, 2024e).

Data and Validation

Utilities have emphasized the importance of consistent, high-quality operational data to accurately assess GETs. However, these data are often limited or not standardized across vendors and regions. Without shared benchmarks or time-resolved data, it becomes difficult to validate performance and reliably model GETs. Additionally, without shared benchmarks or performance metrics, validating GETs functionality, assessing degradation, or comparing lifecycle performance against traditional solutions is difficult.

Integration and Operational Considerations

GETs often require integration with utility systems that were not originally designed to support dynamic or automated technologies. Integrating GETs includes modifications to SCADA and EMS platforms, the establishment of new data and communication infrastructures, and adjustments to protection schemes and operational practices. Utilities have also emphasized the need for improved internal coordination among planning, operations, cybersecurity, and maintenance functions.

To support this transition, research on human factors has become increasingly relevant. While human factors is well established in fields like aviation, medicine, and nuclear energy, it has rarely been applied to grid operations. INL-led human factors research provides practical guidance on incorporating operator perspectives early in the integration process (Li, McJunkin, and Le Blanc, 2021; Li et al., 2022; Li, McJunkin, and Le Blanc, 2024; McJunkin et al., 2025), thereby ensuring the safe and effective deployment of novel technologies.

Regulatory and Cost-Recovery Considerations

Existing regulatory frameworks do not always provide clear pathways for integrating GETs into transmission planning and investment decisions. There can be uncertainty regarding how costs associated with GETs will be recovered, how these technologies will be assessed during cost allocation, and how performance-based solutions or non-wires alternatives will be regarded in competitive transmission solicitations. The absence of clear guidance or incentives can delay or discourage deployment—even when these technologies are cost-effective or technically well suited to a given project need.

Institutional Inertia and Process Misalignment

Many stakeholders have noted that GETs are not yet fully embedded in utility or regional planning processes. In some cases, these technologies are excluded early in project screening, evaluated inconsistently, or treated as secondary to conventional upgrades. Utilities attribute this to a combination of legacy workflows, limited internal familiarity, and the absence of standardized evaluation criteria. As a result, promising technologies may be overlooked—not because they fail to meet system needs, but because they are not readily supported by existing planning frameworks.

While these concerns are valid, they don't necessarily preclude action. In fact, many of the perceived limitations around GETs are already being addressed in practice—or can be managed with the proper planning and policy frameworks.

Addressing Common Concerns: Lessons from Practice

As GETs gain traction, utilities, planners, and regulators have raised important questions about their long-term reliability, planning compatibility, and operational readiness. These concerns are legitimate—especially in the context of system-critical infrastructure—but many are already being addressed through field experience, evolving standards, and early deployment strategies.

This section highlights how utilities and system operators are navigating these challenges in practice. Drawing on lessons from pilot projects, industry studies, and planning efforts, it offers insight into how concerns are being resolved through iterative learning, collaboration, and practical integration. These examples are not intended as one-size-fits-all solutions, but rather as reference points for others facing similar questions in their jurisdictions.

Building Confidence Through Data and Deployment

Concern: The limited availability of performance data makes it challenging to validate GETs in planning studies.

What We're Learning in Practice

There is a growing body of multi-year pilots and deployments across technologies and regions. Utilities are addressing data gaps through structured pilots and early operational use. More than 40 utilities in the United States have deployed advanced conductors, with many of these projects documented in DOE- and INL–supported case studies. Projects like Oncor's 800-mile competitive renewable energy zone (CREZ) reconductoring, PPL's DLR deployment, Southern Company's use of modular APFC, and Alliant Energy's targeted application of TTO have demonstrated technical viability and measurable benefits.

Many concerns are already being addressed through field experience, evolving standards, and early deployment strategies.

Constructive Strategies

- Share pilot results and planning methodologies through public-facing centralized repositories (e.g., INL,[13] EPRI,[14] WATT Coalition,[15] and ESIG[16])
- Use standardized reporting that clearly shows both the benefits (e.g., congestion relief, avoided curtailment), the costs (e.g., installation, maintenance), and the specific system contexts where GETs were most effective
- Support a voluntary, coordinated data-sharing framework to help planners consistently validate GETs' performance

13 https://inl.gov/national-security/grid-enhancing-technologies/

14 https://interactive.epri.com/get-set/p/1

15 https://watt-transmission.org/resource-library/

16 https://www.esig.energy/gets-user-group/

Improving Modeling Approaches for Long-Term Planning

Concern: GETs like DLR rely on real-time inputs and environmental variability that are difficult to incorporate into deterministic long-term planning models.

What We're Learning in Practice

DLR and other GETs can be modeled at whatever time resolution planners require. Just as static line ratings are built from wind speed and temperature averages, DLR performance can be incorporated using monthly, weekly, or seasonal capacity distributions. This doesn't replace deterministic planning—it enhances it by incorporating more realistic assumptions about how line capacity changes over time. Rather than relying on entirely new types of data or planning frameworks, DLR builds on existing inputs—like weather data—to improve the accuracy and granularity of transmission ratings.

Long-term transmission planning needs to be informed by operational insights accumulated over time. Performance data from years of GETs operation can help planners refine dynamic assumptions in future studies. Rather than viewing variability as a limitation, modeling DLR, for example, enables a more accurate representation of how thermally limited lines behave under real conditions.

This mirrors how planners already model variable generation. Long-term studies routinely incorporate 8,760-hour production profiles and uncertainty ranges for wind, solar, and hydro resources. The same methods can be adapted to model transmission capacity that varies with weather conditions. Recent studies—such as those conducted by DOE, INL/Telos, and other industry groups—demonstrate how coupled production cost and power flow modeling can be used to evaluate the operational and economic value of DLR and power flow control across various future scenarios (Gentle et al., 2023; U.S. DOE, 2022).

Constructive Strategies

- Apply hourly, daily, monthly, or percentile-based DLR profiles to long-term models, mirroring how variable generation is modeled
- Work with software vendors to improve native GETs modeling in production cost, power flow, and dynamic simulation tools, and develop best practices for using simulations to evaluate the operational behavior and economic value of GETs under various system conditions
- Encourage collaboration between planning and operations teams to incorporate insights from GETs deployments, calibrate modeling assumptions, and improve the accuracy of long-term scenario analysis

Expanding Modeling Tool Capability and Forward-Looking Studies

Concern: Many planning tools do not yet natively support GETs, making it difficult to evaluate them in long-term scenarios or compare them consistently to traditional upgrades.

What We're Learning in Practice

While traditional planning software was not necessarily built with GETs in mind, forward-looking studies have shown that it can be effectively adapted. Planners are already using production cost simulations, power flow analysis, and stability tools to model the behavior and system impacts of GETs. A growing body of work demonstrates that GETs can be represented in both economic and reliability studies using current industry-standard tools:

- An INL-Telos study of New England used coupled modeling using PLEXOS for production cost and TARA for AC power flow to site PFC devices and assess congestion relief and reliability improvements (Gentle et al., 2024).

A growing body of work demonstrates that GETs can be represented in both economic and reliability studies using current industry-standard tools.

- A Quanta–RMI analysis used PROMOD, TARA, and PSS/E to simulate GETs deployments across PJM, showing production cost savings and improved system reliability (Siegner et al., 2024).
- DOE's New York Independent System Operator case study demonstrated that DLR and APFC can cost-effectively reduce curtailments and congestion over multi-year planning horizons (U.S. DOE, 2022).

Constructive Strategies

- Collaborate with software vendors to improve native GETs support and share models across regions
- Develop and disseminate standard modeling assumptions for DLR, power flow controllers, and TTO
- Encourage national laboratories, federally funded pilots, utilities, and regional transmission organizations to coordinate sandbox exercises to explore GETs performance in realistic grid scenarios
- Share outcomes from forward-looking studies to inform tool enhancements and accelerate the adoption of best practices

Improving Long-Term Reliability and Asset Lifecycle

Concern: GETs may lack the field history and asset life-cycle maturity expected of system-critical infrastructure.

What We're Learning in Practice

Utilities are increasingly managing GETs with the same rigor applied to traditional assets. For example, for advanced conductors, utilities are applying corrosion-resistant materials, refined splicing hardware, and updated installation practices. Several manufacturers now offer training programs and onsite supervision to reduce variability and minimize field-related performance issues.

> **Utilities are increasingly managing GETs with the same rigor applied to traditional assets, and standardized testing is advancing.**

Standardized testing is also advancing. For example, the ANSI C119.7 standard—covering connectors for aluminum conductors operating above 93°C—is expected to improve consistency and confidence in performance across various conductor types.

Importantly, this growing field experience is laying the groundwork for broader adoption. As deployments scale, utilities are gaining operational insight, refining asset planning templates, and improving confidence in GETs' long-term reliability. As with inverter-based resources, repeated use and shared performance data drive the formalization of standards, asset tracking, and integration into planning and procurement.

Constructive Strategies

- Apply the same lifecycle planning principles used for substation equipment and conductors to GETs, including maintenance scheduling, inspection, and asset tracking
- Continue developing industry standards (e.g., ANSI C119.7) to reduce uncertainty around degradation, reliability, and compatibility
- Collaborate with vendors and early adopters to document component-level reliability, inspection needs, and expected service life
- Develop internal processes to transition GETs from pilot to portfolio assets with defined lifecycle support

Clarifying/Addressing Regulatory and Cost Recovery Uncertainty

Concern: GETs fall outside standard cost recovery mechanisms and lack clear treatment in planning and procurement rules. Traditional rate structures tend to favor capital-intensive transmission projects, while many GETs involve modular, lower-cost deployments or operational expenses. This creates a structural disincentive for adoption, even when GETs are cost-effective.

What We're Learning in Practice

Regulators are exploring incentive structures, such as performance incentives, to encourage deployment. The landscape is improving rapidly. FERC Orders 881 and 1920 establish a baseline requirement to use GETs in regional transmission planning.[17] Several states (e.g., California and Minnesota) now include GETs in cost allocation or grid modernization programs.

> **Regulators are exploring incentive structures, such as performance incentives, to encourage deployment.**

Constructive Strategies

- Work with regulators to clarify recovery pathways for both capital and non-capital GETs investments (e.g., pilot programs and telemetry upgrades)
- Consider regulatory models that align GETs' value with utility incentives
- Include GETs in state planning guidance to build regulatory familiarity
- Collaborate with peer utilities to develop coordinated recommendations for consistent treatment of GETs-related operations and maintenance costs

Achieving/Implementing Cybersecurity and Operational Integration

Concern: GETs—especially those using cloud-based or third-party networks—may pose cybersecurity risks and may complicate SCADA or EMS integration.

What We're Learning in Practice

Utilities, like PPL Electric, have successfully implemented DLR in a CIP-compliant architecture,[18] integrating

17 https://www.federalregister.gov/documents/2022/05/25/2022-11233/managing-transmission-line-ratings and https://www.ferc.gov/explainer-transmission-planning-and-cost-allocation-final-rule#_Key_Decisions_of

18 https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx

real-time telemetry into market operations and EMS functions. Their deployment demonstrates that GETs, like DLR, can coexist with existing control infrastructure.

Utilities deploying GETs must carefully evaluate cybersecurity implications related to telemetry and data flows. Many entities subject to NERC's CIP Reliability Standards have mature compliance programs, typically structured around a model where the utility owns and controls all assets within its compliance boundary.

Deployments require attention to both applicability and compatibility with CIP standards. Applicability refers to whether the system falls within the scope of NERC CIP requirements. Compatibility depends on the specific system architecture—such as cloud vs. on-premise hosting—and how it aligns with the utility's existing compliance model.

The INL cybersecurity-focused report outlines considerations for DLR deployment in accordance with NERC CIP requirements (INL, 2024e). The report highlights potential risks, deployment scenarios, and planning factors that utilities should assess when integrating DLR into their existing control systems and compliance environments.

Constructive Strategies

- Apply existing utility cybersecurity frameworks (e.g., NERC CIP) to GETs telemetry and control components
- Include information technology teams, operations teams, and vendors early in the planning and specification process for GETs deployments
- Document integration pathways for SCADA/EMS and share lessons learned across utilities and working groups

Ensuring Planning Flexibility

Concern: Mandating GETs in all planning studies may reduce flexibility and create unnecessary burdens where benefits are limited.

GETs may not be appropriate in every situation and, therefore, should not be required in every case—but they should be seriously and consistently considered.

What We're Learning in Practice

GETs may not be appropriate in every situation and, therefore, should not be required in every case—but they should be seriously and consistently considered. FERC Order 1920 reflects this balance: it requires transmission planners to evaluate advanced technologies where appropriate but stops short of prescribing their use. Similarly, several states, including California, Minnesota, and New York, have integrated GETs into their planning guidance and cost allocation, promoting visibility without forcing deployment.

To promote accountability, some stakeholders recommend that planners document why GETs were not selected in various planning cycles: GETs are thus not mandated but not ignored. Transparency at this level can improve trust, standardize evaluation, and highlight use cases where GETs are especially valuable.

Constructive Strategies

- Adopt a "consider-and-justify" framework for GETs, where planners explain why GETs were or were not selected in each study
- Align GETs treatment with existing expectations for non-wires alternatives—evaluate them on a case-by-case basis without blanket mandates
- Encourage regional transmission organizations, state regulators, and utilities to develop screening tools or decision trees to help identify high-potential use cases
- Use planning guidance and rulemaking (e.g., through FERC or state commissions) to clarify expectations for the fair consideration of GETs

Improving Institutional Readiness and Planning Culture

Concern: Existing planning practices, organizational structures, and study workflows may limit consistent evaluation of GETs.

In many cases, these technologies are excluded early in project screening, inconsistently evaluated, or treated as secondary to conventional upgrades.

What We're Learning in Practice

Institutional barriers remain, but practices are evolving. GETs are increasingly being incorporated into both regional and utility-level planning and operations.

Regional transmission organizations, such as MISO and ERCOT, have integrated tools like topology optimization into their congestion management and seasonal study processes, demonstrating that GETs can be used in conjunction with traditional approaches.

Regional transmission organizations, such as MISO and ERCOT, have integrated tools like TTO into their congestion management and seasonal study processes, demonstrating that GETs can be used in conjunction with traditional approaches. At the utility level, pilot projects and early integration efforts are helping align GETs' capabilities with established investment and evaluation practices.

Federal and regional policy shifts are reinforcing this momentum. FERC Order No. 1920 explicitly requires transmission providers to evaluate GETs—such as DLR, APFC, and advanced conductors—as part of long-term planning processes.[19] This policy acknowledges that GETs should no longer be treated as peripheral or experimental.

Constructive Strategies

- Support internal education and training on GETs and planning integration
- Build cross-functional teams that bring together planning, operations, compliance, and information technology
- Use pilot deployments to refine internal evaluation processes and inform business case development
- Support culture change through case sharing, peer exchanges, and participation in GETs-focused working groups
- Ensure that the operational context is considered in the promotion and attempts to roll out new technologies (Li, McJunkin, and Blanc, 2021; McJunkin et al., 2025)

Together, these insights suggest that while challenges remain, there are clear and practical strategies for incorporating GETs into routine transmission planning and operations. The following section outlines a path forward to help utilities and planners accelerate the adoption and institutionalization of these tools across their organizations.

19 https://www.ferc.gov/explainer-transmission-planning-and-cost-allocation-final-rule#_Key_Decisions_of

A Way Forward

While there are several challenges and barriers regarding their broader adoption, GETs offer innovative solutions to enhance capacity, reliability, and efficiency in power delivery across the power system. Implementing these technologies involves a structured approach that encompasses extensive assessment, compliance with regulations, careful selection of suitable technologies for various applications, and active stakeholder engagement. Their adoption may require changes in how transmission planners plan, assess, and implement transmission upgrades. And transitioning from pilot projects to scalable deployments will require deliberate action in several key areas, including better integration into planning processes, clearer cost-benefit analyses, supportive regulatory frameworks, and consistent data sharing.

Benefits of GETs

GETs are not just a workaround—they're a strategic tool for increasing transmission capacity, reducing costs, and improving grid efficiency. While new transmission lines remain critical, GETs offer near-term, modular solutions that utilities can deploy today to address real-world constraints.

What GETs Can Do

- **Unlock capacity very quickly:** Technologies like DLR, APFC, TTO, and advanced conductors can be deployed within months to increase line capacity by 15% to 50%—providing near-term relief while long-term lines are planned and built.
- **Accelerate interconnections:** By increasing the available capacity of existing infrastructure, GETs can facilitate faster connection of generation and large loads.

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- **Adapt to changing needs:** GETs can be deployed strategically to address localized constraints and adjusted over time, reducing the risk of overbuild or stranded assets.
- **Deliver strong returns:** Compared to traditional transmission builds, GETs are significantly cheaper and faster to implement. Many technologies pay back their costs within 1–5 years by avoiding congestion, deferring upgrades, and improving system flexibility.

Real-World Results

- PPL Electric saved $64 million on congestion with an investment of less than $1 million in DLR.
- MISO's economic TTO process saved $24 million in 2024 alone, from just five reconfigurations.
- AEP's reconductoring project increased capacity by 40% over 120 miles—avoiding costly new right-of-way acquisition.

Momentum Is Building

- FERC Orders 2023 and 1920 now require consideration of GETs in transmission planning.
- FERC's 2024 Advance Notice of Proposed Rule-making proposes requiring transmission providers

to consider real-time weather conditions—like wind and solar heating—when applying DLR, especially on congested lines.

- As of June 2025, more than 20 states had enacted or were considering GETs/ATT legislation

What Needs to Change

- **Planning tools must evolve:** Most current models do not natively support GETs. Enhancing modeling platforms and commercial tools is essential.
- **Regulatory frameworks need to be reconsidered:** They need to support performance-based incentives, enable modular rate recovery, and incorporate GETs into cost allocation and benefit-cost analyses—to address "capex bias" and outdated incentives.
- **Data must be shared transparently:** Broader dissemination of pilot results, performance data, and cost savings will build confidence and support wider adoption.
- **The operational context needs to be considered:** A human factors approach to harmonizing new technology within the existing operational visualization, processes, and procedures will help to address hesitancy to adoption (Li, McJunkin, and Blanc, 2021).

GETs are proven, practical, and increasingly necessary. The technologies are ready—what remains is aligning the processes, tools, and incentives around them.

Making GETs Practical: Planning, Economics, and Deployment Pathways

Short-Term and Long-Term Integration Strategies

The path to widespread GETs deployment spans both short-term action and long-term transformation. Near-term pilots can provide rapid benefits and build confidence. Over the longer term, utilities should integrate GETs into planning, tools, and organizational processes.

GETs are proven, practical, and increasingly necessary. The technologies are ready—what remains is aligning the processes, tools, and incentives around them.

For GETs to scale, planning tools and workflows need to include them by default, which means improving both the technical modeling environment and the institutional process for evaluating GETs alongside traditional infrastructure.

In the near term (0 to 2 years):

- Focus on quick wins such as DLR, APFC, or TTO deployments that reduce congestion and defer upgrades
- Use pilots to demonstrate impact and build confidence across departments
- Prioritize use cases with observable benefits that do not require wholesale system redesign

Over the long term (3 to 10 years):

- Embed GETs into standard planning frameworks and decision-making processes
- Update energy management systems (EMS), market management systems (MMS), and planning models to dynamically represent GETs
- Clarify roles and responsibilities for when, where, and how GETs are deployed—and how cost savings or benefits are allocated

Planning Process and Planning Tool Integration

For GETs to scale, planning tools and workflows need to be adapted to include them by default—not as an exception. This means improving both the technical modeling environment and the institutional process for evaluating GETs alongside traditional infrastructure.

Key steps:

- Embed GETs in standard production cost simulation, power flow, stability, and other reliability tools
- Coordinate assumptions and input data across planning, operations, and regulators to support transparent modeling and consistent evaluation

- Co-optimize GETs with traditional transmission—so that they aren't seen as last-minute fixes but as part of a broader solution portfolio

Use of Consistent Benefit-Cost Methodologies

While upfront costs for GETs vary by technology, they are generally significantly lower than those for conventional transmission upgrades. Advanced conductors typically cost from $500,000 to $1 million per mile, while modular DLR or APFC systems can be deployed for less than 10% of that. Costs include devices, installation, integration, and data management—but operational savings and congestion reduction often pay back investments within 1 to 5 years, or even months. However, the operational costs incurred through additional risk or increased operator workload need to be concretely evaluated to overcome hesitation in adopting new technologies (Li, McJunkin, and Blanc, 2021; McJunkin et al., 2025).

GETs' multiple economic and operational benefits include:

- Increased transfer capacity and congestion relief
- Deferral or downsizing of major capital projects
- Greater visibility and situational awareness for grid operators
- Acceleration of generator or load interconnections

Key steps:

- Evaluate GETs early in project screening using consistent benefit-cost methodologies
- Build internal guidance to benchmark GETs against traditional upgrades—not as a separate category, but as part of an integrated solution set
- Encourage and provide methods to evaluate the risks and benefits of the technology in technical and operational contexts through a human factors approach

Policy and Market Enablement

Despite their proven value, GETs are underutilized partly because regulatory and financial frameworks prioritize large capital investments. Utilities earn returns on capital expenditures, making modular technologies like GETs less attractive. A 2024 study by the Massachusetts Institute of Technology highlights this long-standing "capex bias" as a key barrier (Deese, Gramlich, and Pasnau, 2024). For example, advanced conductors and other GETs may be overlooked because they offer less profit potential than building a new transmission line. At the same time, advanced conductors may face regulatory resistance for being more expensive than conventional conductors and may be mischaracterized as "gold-plating." To move GETs from exception to option, incentives and cost-recovery mechanisms must reflect operational value.

Key steps:

- Support performance-based incentives or shared-savings models for reducing congestion and deferring upgrades
- Create regulatory pathways for incremental and modular rate recovery
- Include GETs in transmission cost allocation and benefit-cost methodologies
- Reward congestion reduction in wholesale markets, regardless of how it is achieved

Lessons from Pilots

Pilot projects are essential, but their value is multiplied when lessons are shared among users and other impacted parties. It is critical to share outcomes—both setbacks and successes. Transparent reporting builds confidence, reduces uncertainty, and accelerates broader adoption.

Government and industry organizations can help coordinate centralized repositories of deployment outcomes, technical data, and planning templates:

Key steps:

- Promote GETs-focused user groups or clearinghouses to share performance data and planning experiences
- Standardize pilots' reporting frameworks to improve comparability of costs, benefits, and integration pathways
- Expand and update public case studies—such as INL's summaries on advanced conductors, DLR, and APFC—to reflect recent deployments and technical insights[20]

Improved Data Collection and Feedback Loops

GETs' adoption depends on confidence—built through performance data, cost tracking, and transparent reporting. Without robust feedback loops, utilities and regulators cannot fully quantify GETs' impacts or integrate lessons into future planning.

Key steps:

- Enable shared access to performance data through collaboration between utilities, vendors, regional transmission organizations, and national laboratories
- Deploy advanced monitoring and analytics tools to gather real-time data on line temperature, sag, power flow, and reliability performance
- Establish regulatory reporting frameworks with standardized GETs metrics, including costs, congestion reduction, curtailment avoided, emissions impact, and interconnection acceleration

20 Also see https://inl.gov/national-security/grid-enhancing-technologies/, https://interactive.epri.com/get-set/p/1, https://watt-transmission.org/resource-library/, and https://www.esig.energy/gets-user-group/.

Proposed Steps for Implementation

Scaling GETs from pilot projects to routine deployment requires a coordinated, multi-step process. This journey includes early-stage assessment, stakeholder alignment, structured pilot programs, and integration into long-term planning frameworks. See Table 1.

Many GETs have progressed beyond the demonstration stage, with deployments in a range of jurisdictions and applications providing valuable performance insights. While system conditions and operating environments differ, utilities can often benefit from drawing on lessons learned from prior pilots and deployments instead of conducting duplicative demonstrations. Leveraging shared experience can help shorten implementation timelines and focus resources on effective integration and scaling.

Grid-enhancing technologies offer practical, proven tools to address many of today's most pressing transmission challenges. By building on early utility experience and aligning planning, operations, and markets, the industry can begin to deploy these technologies more broadly and systematically. Continued collaboration across utilities, regulators, vendors, and other stakeholders will be essential to fully integrate these solutions into standard practice and realize their potential for improving reliability, efficiency, and grid performance.

TABLE 1
Proposed Steps for GETs Implementation

Assessment and planning ▼	Utilities begin by assessing their existing infrastructure to identify where GETs can provide the most benefit. This involves analyzing transmission line conditions, load patterns, congestion hotspots, and integration points for new resources and demand.
Cost-benefit analysis ▼	A detailed economic analysis is conducted to evaluate whether GETs can deliver value in terms of capacity, reliability, and cost savings. This includes comparison with traditional solutions.
Technology selection ▼	Based on needs and system characteristics, utilities select appropriate GETs. Selection is informed by site specifics, expected benefits, and integration complexity.
Pilot projects ▼	Before scaling up, utilities often run pilot projects to test GETs under real-world operating conditions. These pilots help validate performance, uncover potential issues, and build internal expertise. Where prior demonstrations—including those conducted by other utilities—already provide relevant evidence, utilities may reference those results and focus their efforts on integration and scaling.
Data collection and analysis ▼	During the implementation of pilot projects, utilities collect detailed operational data to assess GET effectiveness. Continuous monitoring supports evidence-based decisions and informs refinements in system operation and planning assumptions.
Stakeholder engagement ▼	For successful implementation, utilities engage with stakeholders including regulators, customers, and other utilities to ensure that all parties are aligned and supportive of the changes.
Overcoming regulatory hurdles and increasing community acceptance ▼	To ensure that their GETs implementation plans comply with local, state, and federal regulations, utilities obtain the necessary permits/approvals and propose reasonable cost recovery frameworks, including a return on investment.
Full-scale deployment ▼	With stakeholder alignment, validated technology, and regulatory approval, utilities proceed to full-scale deployment. This may be staged across circuits or substations based on urgency and resource availability.
Training and workforce development	GETs may require new technical, operational, and planning skills. Utilities invest in workforce training to ensure effective deployment, integration, and long-term asset management.

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PHOTOS

Appendix: Participating Organizations

This report was produced by the ESIG Grid-Enhancing Technologies User Group, which includes a variety of members with differing viewpoints and levels of participation. Specific statements may not necessarily reflect a consensus among all participants or the views of the participants' employers.

Members

The user group has representatives from:

- American Electric Power
- AES Corp
- Alliant Energy
- Bonneville Power Administration
- California Independent System Operator
- Central Hudson Gas
- ComEd
- Duke Energy
- Electric Reliability Council of Texas
- Exelon
- Garland Power & Light
- Georgia Power Corp
- Idaho Power Company
- Louisville Gas and Electric and Kentucky Utilities
- LS Power
- Midcontinent Independent System Operator
- Oncor
- PacifiCorp
- PJM
- Portland General Electric
- Powder River Energy Corp
- Salt River Project
- Sacramento Municipal Utility District
- Southern California Edison
- Southern Company
- Tennessee Valley Authority
- Vermont Electric Power Co
- Western Area Power Administration
- Western Electricity Coordinating Council
- Wisconsin Public Power Incorporated Energy
- Xcel Energy

Utility Perspectives on Making Grid-Enhancing Technologies Work: Use Cases, Barriers, and Recommendations for Scalable Deployment

A Report by the Energy Systems Integration Group's Grid-Enhancing Technologies User Group

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This report is available at https://www.esig.energy/gets-user-group/utility-perspectives-report/.

To learn more about ESIG's work on this topic, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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