Smarter use of the dynamic grid

Accessing transmission headroom through GETs deployment

Smarter use of the dynamic grid

Accessing transmission headroom through GETs deployment.

The electrical grid is ready for accelerated modernization. From large electricity customers (like data centers) to small customers (like residential), the number of load consuming assets is increasing, and total electricity demand is growing alongside.[1] The location of load and supply is also changing as customers and communities invest in generating assets and batteries move between charge and discharge throughout the grid. Customers increasingly request (and society needs) efficient green electricity sources, leading to more inverter based and IoT[2] digital resources. These changes clamor for a modern grid that is capable of managing rapid growth, flexible assets, and big data to deliver what our customers desire safely, reliably, and affordably.

Introduction

The substantial increase in renewable energy projects installed and waiting for connection to the grid has created significant transmission capacity challenges, including in planning and operations. According to the Department of Energy (DOE), the US needs to more than double its regional transmission capacity to meet the country's goal of 100% clean energy by 2035.[3] In 2022 there were nearly 2,000 GW of renewable energy projects waiting in long queues to connect to the grid despite soaring network upgrade costs. Both delays and costs are a function of insufficient transmission capacity[4] and conventional processes for planning and modeling. In operations those same challenges cost US consumers an estimated $20B+ in congestion charges in 2022, up more than 50% from the year before.[5]

Conventional processes for planning and modeling the grid (including forecasts of changing load, new generation, and increased transmission capacity) are highly manual, deterministic,[6] conservative, and based on hundred-year-old grid concepts. But change is difficult, particularly in conservative environments that rightfully protect grid reliability. In the case of transmission capacity this means that transmission owners (TOs) generally prefer, RTOs support, and regulations encourage traditional investments like conventional line reconductoring,[7] line rebuilds, or entirely new transmission lines. Even when the need for change is recognized, the process is incremental, at risk of perfectionism, subject to extended implementation periods, and expensive.

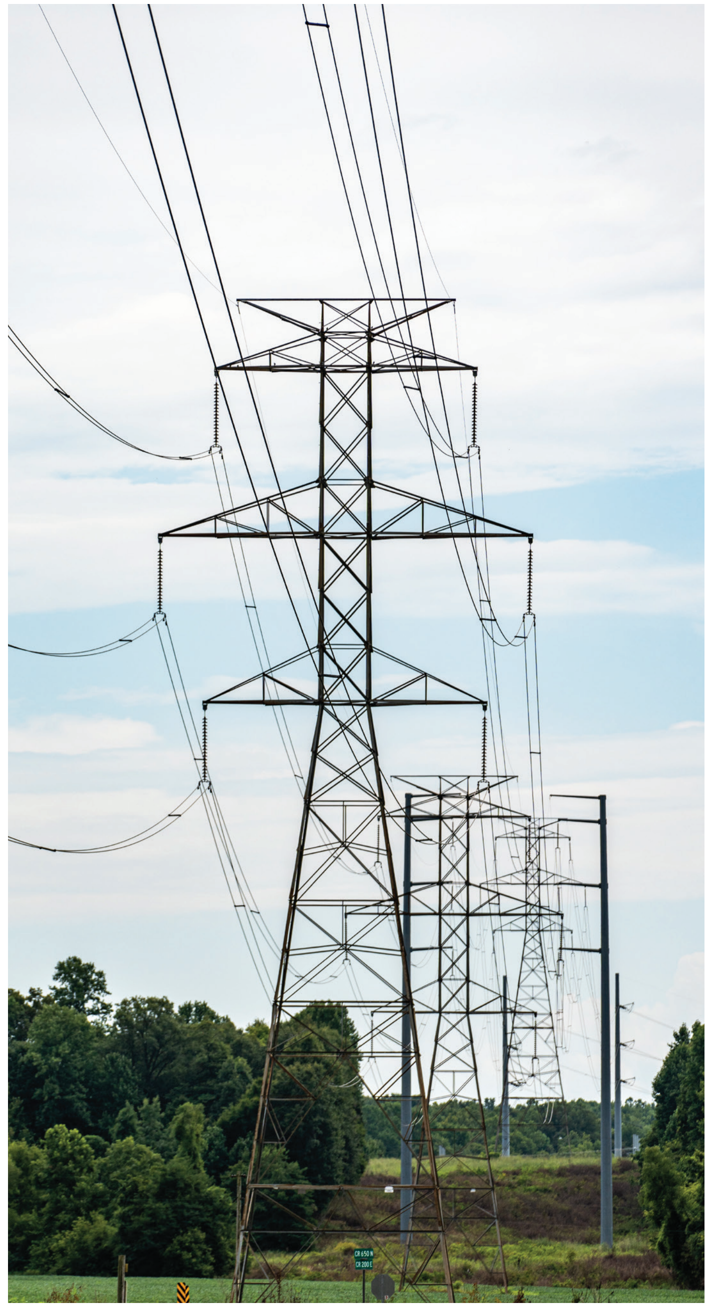
1. Grid Strategies, "The Era of Flat Power Demand is Over" (December 2023), accessed Feb. 21, 2024 at https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.
2. IoT means "internet of things", or a network of connected physical devices that include sensors and software and can communicate to the data cloud and between each other.
3. US Department of Energy (DOE), "National Transmission Needs Study" (October 2023), accessed on Feb. 21, 2024 at https://www.energy.gov/sites/default/files/2023-10/National_Transmission_Needs_Study_2023.pdf.
4. Lawrence Berkeley National Laboratory (LBNL), "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022" (April 2023), accessed on Feb. 21, 2024 at https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf.
5. GridStrategies, "Transmission Congestion Costs Rise Again In U.S. RTOs" (July 2023), accessed Feb. 21, 2024 at https://gridstrategiesllc.com/wp-content/uploads/2023/07/GS_Transmission-Congestion-Costs-in-the-U.S.-RTOs1.pdf.
6. Deterministic modeling suffers from the elimination of externalities, randomness, and probability. In other words, the belief that all needed data is accurately included in the model and that the outcomes modeled will occur.
7. As opposed to reconductoring with advanced conductor technologies.

GETs In operations and planning

TOs typically plan to reconductor, rebuild, or build new lines when they identify a need for additional transmission capacity.[8] These conventional tools often require significant capital investment and extended implementation periods, including expense and delay related to permitting and right of way acquisition. In contrast, Grid Enhancing Technologies (GETs) are hardware and software that enable TOs to dynamically expand transmission capacity quickly and cost-effectively on existing lines, facilitate construction of new lines, and maximize throughput or right-size investment on newly built lines.[9]

GETs not only improve transmission capacity, reliability, safety, and grid efficiency but also create beneficial externalities. GETs introduce flexibility and create data insights, which – in turn – enhance grid reliability through real-time visibility into grid conditions and opportunities for grid optimization. They can adapt grid infrastructure to meet contemporary and future energy demands while improving the rate at which new generation can be connected to the grid.[10]

This section describes four commercially available GETs and how they can be deployed more fully in the near term into grid planning and operations so our system and customers can benefit from their early use today and fuller, high-fidelity use as the grid becomes more data rich and digitally enabled. We focus on topology optimization, advanced power flow control, dynamic line rating, and storage as transmission because of their software-enabled and dynamic nature. Paths to technology deployment and policy improvements are left to the next section.



8. Need identification may take place through the TO's planning process, identified repeat reliability or congestion issues, or new generation interconnection reliability modeling.

9. The Brattle Group, "Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts" (April 20, 2023), accessed on Feb. 21, 2024 at https://www.brattle.com/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf.

10. The Brattle Group, "Unlocking the Queue with Grid-Enhancing Technologies" (February 1, 2021), accessed on Feb. 21, 2024 at https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf. This study found that GETs could double the potential for renewable energy interconnections and that the costs would be recovered in six months.

A. Topology Optimization

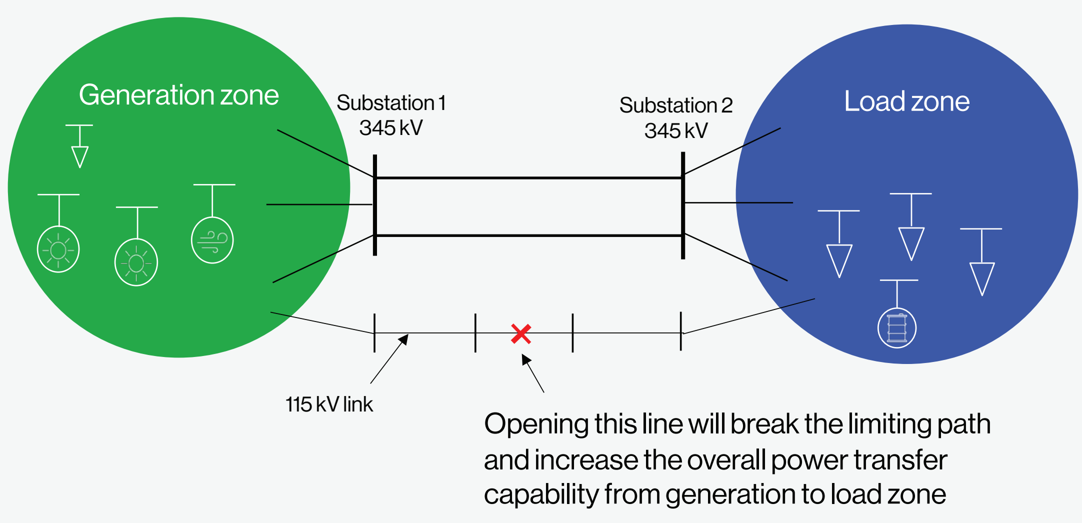
Topology optimization refers to the strategic reconfiguration of the power grid's structure by switching the status of circuit breakers, switches, or other controllable devices. This process involves switching transmission lines in or out and/or splitting bus sections. For example, if load is growing rapidly and stressing one feeder, grid operators can transfer all or part of the load to adjacent feeders through switching actions at substations and minimize the risk of equipment failure and outages.[11] Studied topology optimization solutions[12] can be applied quickly to mitigate unexpected events like equipment failures or demand changes.

The objectives of topology optimization in operations include increasing power transfer capability, relieving grid congestion, improving voltage profiles for grid stability, and minimizing the impact of a contingency event on grid reliability. Meeting these objectives allows (a) more efficient use of transmission lines and system assets, (b) avoidance or mitigation of overloads, thereby reducing the need for energy curtailment or expensive redispatch, and (c) increased integration of renewable energy resources, both at utility and distributed scale.

The insights derived from use of topology optimization in operations can support effective long-term planning decisions. For example, if a particular topology optimization solution is regularly used in operations, planners could recognize it as a permanent configuration change. Certain topology optimization solutions can effectively address reliability issues and thereby lead to reduced network upgrade costs when connecting new generation projects. Topology optimization solutions also allow planners to proactively identify potential bottlenecks, areas of underutilized capacity, or even strategic locations for new infrastructure.

Taking a proactive and dynamic approach to grid topology could help affordably integrate new renewable energy at the speed needed to meet decarbonization objectives and help build a more flexible grid that better reflects the increasingly digital and distributed assets that make use of wires and substations. Indeed, topology optimization should be a foundational characteristic of how we operate and plan our increasingly digital grid.

Topology optimization reconfigures transmission topology to increase power transfer capability



11. Sources of feeder stress also include when voltage of a feeder is low or decreasing or in cases of sustained high load such as a summer peak (and potentially winter peak with increased heat pump adoption).
12. Example PJM switching solutions can be found at this site accessed on Feb. 21, 2024 https://www.pjm.com/markets-and-operations/etools/oasis/system-information/switching-solutions.aspx.

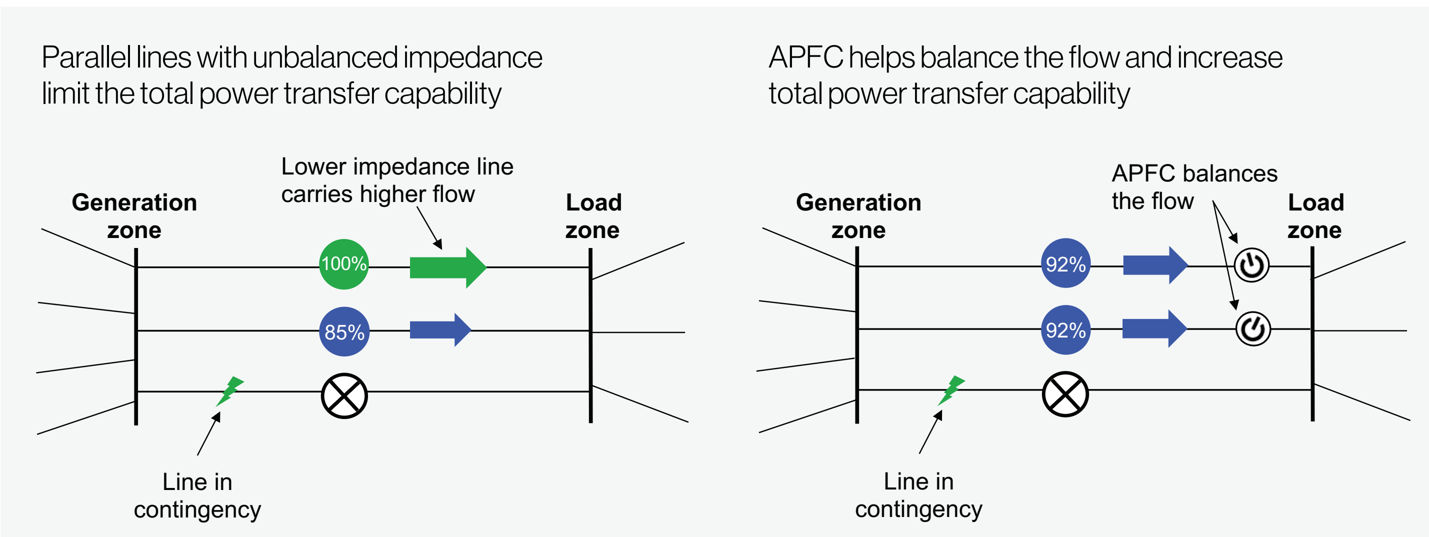
B. Advanced Power Flow Control

Advanced power flow control (APFC) has emerged as a valuable tool in managing real-time power flows across the transmission network, helping operators mitigate congestion and optimize the use of available transmission capacity while maintaining grid reliability. APFC controls the magnitude of power flows along specific transmission paths and can mitigate thermal and stability issues that arise by changing the flow to alternative paths.

APFC is a recent addition to the suite of Flexible Alternating Current Transmission Systems (FACTS) technologies that use power electronics to modify the line impedance, phase angle, and voltage magnitude of the transmission system. FACTS such as static synchronous compensators (STATCOMs) and static var compensators (SVCs) have been employed for decades in the transmission system. APFC improves upon traditional FACTS devices by using modular digital power flow control technology for speedy and accurate control of power flow.

The ability to change power flow has clear operational uses. First, it is especially important in operations to address contingency events such as sudden and unplanned loss of critical generation or transmission facilities. After a contingency, APFC can help redistribute power flows to alternate paths and relieve stress on the grid. Second, the technology can optimize power flow distribution and improve power transfer capability by reducing loop flow.[13] Finally, and similar to Topology Optimization, APFC can improve the post-contingency damping performance[14] of the system, which is crucial for system stability in grid operations.

In the planning horizon, APFC can help create a more flexible and resilient power grid, allowing for greater integration of renewables without necessitating extensive and costly transmission upgrades.[15] By enabling more granular control over power flows, APFC allows planners to explore and evaluate a wider variety of grid expansion and reinforcement options, ensuring that investments are targeted, optimized, and aligned with future grid evolution and policy trajectories. It is crucial to ensure that planning processes accurately reflect the dynamic control capabilities of APFC technology, resulting in a robust, adaptable, and sustainable grid.



13. Loop flow is the difference between actual system power flows and the scheduled flow due to the physical characteristics of the electric network. Loop flows can cause severe reliability issues in real-time operations if not properly managed.
14. Damping performance refers to the ability of the system to counteract oscillations that arise due to disturbances, such as faults, load changes, or switching actions.
15. Indeed, APFC has been recognized in PJM as a valid network upgrade mitigation. See Rocky Mountain Institute, "GETting Interconnected in PJM" (February 2024), accessed on Feb. 19, 2024 at https://rmi.org/insight/analyzing-gets-as-a-tool-for-increasing-interconnection-throughput-from-pjms-queue/ for a case study on the topic. APFC is also part of the list of Alternative Transmission Technologies listed in FERC's Order 2023 (supra footnote 40).

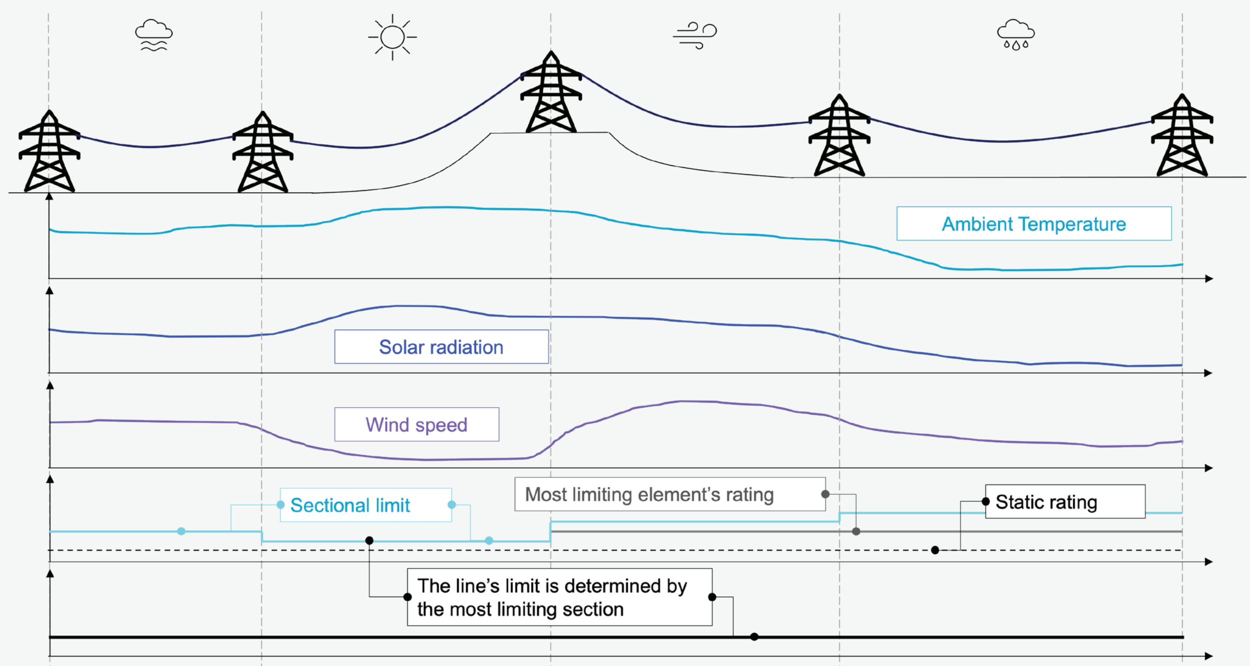
C. Dynamic Line Rating

Dynamic line rating (DLR) is a system that uses real-time and forecasted environmental conditions (and sometimes physical inputs like vegetation and line sag), to continually calculate the thermal carrying capacity of transmission lines. Traditionally, TOs use static or seasonal line ratings based on worst-case assumptions – for example, the hottest time and day of the season under low wind speeds. This often results in conservative ratings that do not accurately reflect the true thermal capacity of a line at a given point in time.[16] In contrast, DLR provides real-time visibility into line capacity and customized rating profiles on lines that are otherwise identical.

The benefits of DLR are particularly great in high wind areas because wind can cool conductors quickly and enable them to carry more current. Similarly, lines can carry more current in lower temperatures, so utilities with transmission constraints during winter peaks are likely to benefit significantly from DLR. The value of DLR is not limited to these use cases, however, as they generally provide improvement from static ratings and reveal additional transmission headroom above ambient adjusted ratings.[17] When DLR does not unlock additional headroom, it reveals opportunities to operate assets more safely and reliably.

After sufficient validation of sensor data and calculations, DLR can be integrated into TO and RTO control systems to operationalize the dynamic ratings for fuller use of grid carrying capacity. Leveraging DLR data in system operations can result in less asset curtailment, reduced congestion costs, increased system reliability and safety, and potentially a reduced reliance on fossil-based resources. DLR data can also provide practical benefits in the field by enhancing operational intelligence and situational awareness, which can be particularly useful for effective line maintenance and vegetation management.

Line ratings are dynamic, changing with ambient and physical conditions



16. In certain cases, the dynamic rating of a line will be less than the static rating. This information is particularly valuable for maintaining reliability and safety.
17. Ambient adjusted ratings may adjust ratings hourly or daily based on temperature weather modeling, but they make assumptions about local wind speed and other factors that contribute to conductor conditions. For a paper on the additional headroom above ambient adjusted ratings, see the MIT paper titled "Impacts of Dynamic Line Ratings on the ERCOT Transmission System", 2022 North American Power Symposium, T. Lee, V.J. Nair, and A. Sun (2022).

DLR is also powerful in its ability to forecast near-term expected line ratings. Forecasted day-ahead line ratings can be used in the RTO market engine to run and clear the day-ahead market. RTOs are already beginning to integrate ambient adjusted ratings (AAR) into their transmission operations process with FERC Order 881 compliance dates as soon as early 2025. DLR is a higher fidelity, more accurate version of AAR that measures additional variables with material impact on the conductor heat balance. This improved accuracy allows for better situational awareness of a line's operating capacity and gains of additional throughput above AAR. Line ratings can be updated in every forecasting cycle using the best available information and with an appropriate reserve margin to avoid "rating shock" from unexpected fluctuations in ambient conditions. The latest ratings can be used in real-time market optimization for the binding and advisory runs and in the Energy Management System (EMS) for real-time contingency analysis.

The benefits of DLR extend beyond grid and market operations into long-term grid planning. The data from DLR enables TOs to make smarter investment decisions by providing a more granular understanding of line capacities and their variability. For example, if DLR data indicates that a non-conductor device, such as a breaker, is frequently limiting a line's capacity, upgrading the breaker could be a simpler and more cost-effective option than reconductoring or building a new line. In this context, DLR data insights would substantiate an upgrade and then allow for full utilization of the line. Also, DLR technologies that consider line sag and vegetation encroachment can surface opportunities for improvements in line carrying capacity through lower-cost strategies like installing guy lines to tension poles or tree trimming. This data-driven approach ensures investment decisions are based on actual line performance rather than conservative static ratings.

In addition, DLR can provide the flexible transmission capacity needed to facilitate longer lead-time transmission planning solutions that require investments in poles and wires. For example, transmission investments typically require months-long outages to construct and commission new assets. These outages reduce the overall system's transmission capacity and could lead to more frequent overloads and require challenging mitigation solutions. Strategic use of DLR can increase the capacity of neighboring lines and improve reliable operations of the system while traditional investments are implemented.

Finally, DLR data is capable of practical application in long-term planning by enabling risk-based rating decisions. With a statistically relevant data history of DLR calculations, TOs can perform analyses and use those findings to create increasingly more granular ratings (but still with a margin of conservatism) to inform transmission planning and interconnection. For example, the Canadian electric utility BC Hydro evaluated multiple line rating techniques and concluded that seasonal static ratings could be improved significantly by adopting a monthly, probabilistic rating methodology enabled by DLR data. In addition, the utility found that using day- and night-time ratings could further improve line rating accuracy.[18]

18. Idaho National Laboratory, "A Guide to Case Studies of Grid Enhancing Technologies" (October 2022) (INL-MIS-22-69711) accessed on Feb. 21, 2024 at https://inl.gov/content/uploads/2023/03/A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf.

D. Storage As Transmission

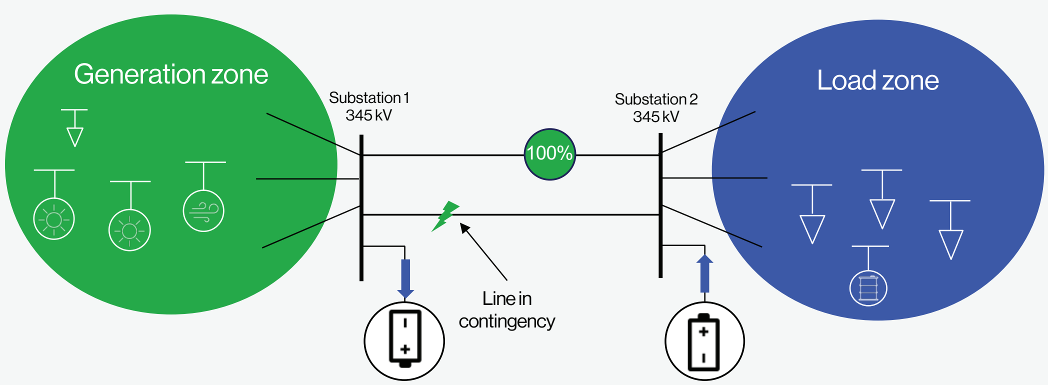
Energy storage is highly flexible and, therefore, ubiquitously referenced as an essential tool in a decarbonized energy system. Among storage's many roles (e.g., as energy or providing ancillary services like voltage and frequency regulation), is its ability to integrate into and enable a transmission network to continue serving energy to load even when the transmission lines themselves are congested or experiencing a contingency event. When storage is deployed as a transmission asset, it can increase energy deliverability and improve overall grid reliability.

In operations, Storage as Transmission (SAT) can absorb excess generation during periods of low load and store it near load to dispatch during peak periods when transmission lines risk congestion. Using storage in this way reduces system costs from congestion pricing and can reduce harmful pollutants and overall carbon emissions by avoiding use of peaking thermal power plants. This use case for SAT can be enhanced by (and can enhance) DLR because the dynamic headroom on a transmission line can be optimally used through combination of GETs.

Another role for SAT is as an electrical system "shock-absorber" capable of providing a short-term buffer of energy during contingency events to enable system operators to redispatch or reroute energy (with traditional methods or using Topology Optimization or APFC), around the contingency. This role is unlocked by storage's ability to ramp up quickly, which also allows it to provide the previously referenced fast-responding frequency regulation and voltage support as a reliable source of operating reserves for maintaining grid stability. DLR can enhance this use case for SAT by allowing storage to provide other grid services during predictable intervals when there is sufficient real time and forecasted headroom in the transmission lines.

In planning scenarios, SAT can be deployed to defer or even mitigate identified transmission investments. The proactive integration of SAT into the grid provides additional capacity and flexibility while supporting the grid to accommodate growing and shifting loads, integrate renewable resources, and meet policy objectives such as decarbonization and reliability enhancement.

SAT can reduce renewable curtailment and load interruption



Battery on the generation side charges to absorb energy while transmission is constrained

Battery on the load side discharges to provide energy to the load while transmission is constrained

A systems approach to accelerating adoption of GETs

GETs are under-deployed on the US power grid relative to their established technical capability.[19] This enigma may be significantly explained by a few barriers that should be directly addressed and resolved so we unlock the benefits of GETs for the grid and its customers at an accelerated pace and in support of a timely transition to a decarbonized electrical system. The first barrier relates to knowledge – because GETs have not been widely deployed in the US, many decision-makers and modeling engineers lack the foundation and confidence to proactively support GETs in planning, operations, and grid upgrades. To address this barrier, the first part of this paper provided a primer on the technologies in those contexts.[20]

But even with better education and understanding, GETs are likely to remain under-used unless we address the following additional barriers: (i) getting example deployments onto the grid in the US to demonstrate feasibility and value within US regulatory and technical requirements; (ii) ensuring funding and cost-recovery mechanisms that encourage application of GETs; and (iii) creating guidance for line owners and transmission authorities to encourage them to take proactive steps to incorporate GETs into their system processes. This section considers these three barriers and provides some recommendations about how barriers can be mitigated to accelerate the future of the grid. This section will address these barriers at a high-level and with the understanding that any solution will require thoughtful discussion among stakeholders.

A. Demonstrations of GETs Viability and Value

Certain demonstrations of the useful deployment of GETs could help accelerate adoption of GETs into the US electrical grid. This section enumerates several use cases for each type of GET covered in this paper but notes that it is likely the combined application of GETs within an electrically related area that will produce step-change value for the system. For example, and as described above, the combination of DLR and SAT technologies can result in a right-sized and firm deployment of each technology to the benefit of the grid and grid customer.

First, Topology Optimization may experience broader deployment if approached proactively and with the objective of creating system flexibility and resilience. Effective topology optimization requires operations engineers to study potential configurations to understand a topology's potential implication on system reliability (both thermal and stability) and protection before they are deployed. With proactive studies, operations engineers can identify and proceduralize beneficial topology solutions and their use cases. The procedure will need to be reviewed periodically to ensure continued accuracy and benefit.

A few applications that operations engineers may proactively look for include:

(a) increasing pre-contingency transfer capability on a higher voltage path by breaking a constrained lower voltage parallel path that limits power transfer capability on the higher voltage path.

(b) providing voltage control by de-energizing transmission lines to bring voltages down into acceptable ranges for lightly loaded lines that generate excessive reactive power and local overvoltage during off-peak hours.

(c) reducing and/or localizing reliability risks in response to a stressed feeder by either (i) transferring all or part of the feeder's load to adjacent feeders through substation switching or (ii) using a bus split to radialize specific parts of the system so that only the load at the end of the radial path is at risk if the line were to trip.

19. See example case studies for: GETs generally (https://watt-transmission.org/wp-content/uploads/2024/01/Case-Studies-and-Modeling-on-the-Value-of-Grid-Enhancing-Technologies-–-January-2024-.pdf); DLR (https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Jul/IRENA_Dynamic_line_rating_2020.pdf?la=en&hash=A8129CE4C516895E7749FD495C32C8B818112D7C and https://www.entsoe.eu/Technopedia/techsheets/dynamic-line-rating-dlr); Power Flow Control (https://www.entsoe.eu/Technopedia/techsheets/static-synchronous-series-compensator); SAT (https://arena.gov.au/projects/ballarat-energy-storage-system/ and https://ir.fluenceenergy.com/news-releases/news-release-details/worlds-largest-storage-transmission-project-announced-fluence), all accessed on Feb. 21, 2024.

20. There is not an intent to imply that what is done in this paper is sufficient in way of education – it is merely one contribution of insights and more is needed. Another source of insights is RMI's recent report on GETs as they may be applied in PJM, which provides a meaningful start to considering how GETs might be modeled and their benefits quantified. Rocky Mountain Institute, "GETting Interconnected in PJM" (February 2024), footnote 15, supra.

Topology optimization deployments will be more successful if the following are considered:

(1) Ensuring that topological changes are well-coordinated with other control actions, such as generator dispatch or shunt compensator adjustments, to avoid conflicting operations or violating operational constraints.

(2) Basing optimizations from sufficiently accurate planning forecasts related to load growth, generation patterns, and technology advancements. Inaccuracies or uncertainties can lead to sub-optimal or impractical planning outcomes.

(3) Careful monitoring of wear and tear on switching devices involved in the solution. Existing breaker and switch technologies were not designed for frequent switching, and they should be monitored to prevent unexpected failures.

Second, early deployment use cases for Advanced Power Flow Controls can be identified by planning engineers by reviewing historical data about grid performance and power flows. Engineers should review operational information to identify areas of the grid that regularly experience congestion, are at risk for reliability failures, or are sufficiently critical corridors in which the ability to manage power flow more closely creates a valuable cost/benefit result.

A few opportunities that planning engineers may look for include:

(a) adjusting the impedance or phase angles along a transmission path to optimize the power flow distribution and prevent premature power transfer limitations in historically congested areas of the grid.

(b) bypassing the series capacitor to increase the impedance of a line and redistribute power flows through other paths to reduce the occurrence of loop flow on traditionally higher-risk transmission paths.

(c) creating responsive and specific power flow control capability on critical grid corridors to avoid cascading failures in the case of major contingency events.

Successful deployments of APFC in planning and operations should consider the following:

(1) APFC devices can inject harmonics and cause electromagnetic interference in the grid. Managing these aspects without adversely impacting the performance of the equipment demands careful harmonic analysis and filtering solutions.

(2) The dynamic control actions of APFC can interact with grid protection schemes, potentially impacting fault detection and isolation. Detailed studies and adaptive protection schemes can ensure that APFC does not inadvertently compromise grid safety.

Third, planning or operations engineers can identify valuable deployments for Dynamic Line Ratings by reviewing historical and forecasted data about power flows, load growth, generator additions, and asset health to anticipate potential grid congestion. For example, engineers may review forecast models to anticipate congestion created by growing loads or connection of new generation facilities. Based on asset health, maintenance schedules, planned upgrades, and new builds, engineers may also identify at-risk lines due to the planned outages required for construction that may cause increased throughput on connected lines.

Opportunities may also be proactively identified by looking for high wind areas that are good candidates for ambient cooling of the conductor, or by considering line conditions more broadly while re-rating lines for AAR as part of the compliance process to FERC Order 881. It is notable that insights from planning and interconnection studies can help identify the mentioned opportunities and it is recommended that those studies be reviewed with an eye to identifying applications for DLR.[21]

21. H. Zhang, N. Diltz, et al., "Time Series Power Flow and Contingency Analysis with Weather Adjusted Line Ratings: A Synthetic WECC Case Study," to appear in 2024 IEEE PES General Meeting.

A few opportunities that planning or operations engineers may look for include:

(a) no-regrets applications based on current or anticipated congestion relief needs as benefit-cost analysis is likely to be clear when compared to longer lead-time reconductoring or new build investments. Quick improvements in line carrying capacity can be immediately beneficial to grid customers and generators.

(b) areas at risk for reliability failures where potential thermal violations are within the 30% average increase often found through application of DLR technology and the conductor is the limiting element (or can be made the limiting element affordably).

(c) high-traffic or system critical lines that can benefit from the dynamic flexibility offered by DLR, effectively acting as an insurance policy or release valve against thermal overloads or non-essential redispatch of generation.

Successful deployments of DLR will consider the following characteristics of the technology:

(1) DLR provides visibility into the actual carrying capacity of lines. This can result in marginal, meaningful, or even significant increases to line ratings on a percentage basis, but it can also result in decreases if it reveals inaccurate assumptions to line carrying capacity across certain stretches or under certain ambient conditions.

(2) DLR can reveal significant opportunities for lines in high wind areas as the impact of wind traveling over a conductor is generally highly relevant for carrying capacity.

(3) DLR may be useful on sub-transmission lines where the risk of redistribution from high voltage transmission lines can put lower voltage lines at risk of incremental overloads easily resolved through visibility into dynamic carrying capacity.

(4) DLR can be deployed and can begin delivering ratings improvements within 3 months vs. the 2+ years it may take to reconductor a line or 10+ years for a new line. DLR can thus be considered as a bridge investment to deliver grid benefits in the short term while waiting on longer term investments. After new infrastructure is built, some DLR technologies enable sensors to easily be moved to another line.

(5) DLR can have minimum grid and safety impact to deploy as there are technologies that are non-contact to the line and can be deployed without an outage and – once deployed – do not change electrical attributes like the impedance of the network.

(6) Some DLR technologies can provide additional grid benefits by providing in-the-field awareness from LiDAR imagery such as detecting conductor sag from ice load.

(7) Integrating DLR data into existing EMS and market processes may require upgrades to existing systems and cyber security processes including NERC Critical Infrastructure Protection plans. Early engagement and scoping of any needed improvements is advisable to ensure interoperability and data consistency across systems.

Finally, storage has the potential to be a flexible building block of the emerging modern electrical grid if planning engineers take the time to evaluate the optimal placement of Storage as Transmission in the grid. For greatest effect, SAT should generally be located close to a load center or along a radial transmission path with a high shift factor.[22] Also, planners should consider that storage assets behave both as load and supply as this flexibility can provide additional grid benefit or can risk overloads if insufficiently planned or incorrectly controlled.

22. Shift factor is a measure of line flow sensitivity to a generator's output. For example, if a generator has a 0.3 shift factor on a line, it means every 10 MW output increase from the generator will increase the line flow by 3 MW. Shift factors are bounded between -1 and 1.

Planning engineers should look for early deployment opportunities for SAT such as providing:

(a) a capacity release service on a radial transmission path connecting two areas. Well-placed SAT can provide reliability protection in case of a contingency event, allowing the path to operate at a higher capacity if it was limited by a contingency.

(b) further on, and when coupled with DLR and intelligent controls, the SAT could be used for market applications during periods when grid conditions do not require the SAT as a reliability backstop. This dual participation of storage as a transmission and market asset[23] enables more efficient use of the resource and has been done in Australia.[24]

(c) upgrade deferral to frequently congested transmission equipment serving a load center. As an alternative to building additional transmission or local generation in a growing load center, a battery can provide peaking capacity as a transmission asset. This SAT application is appealing because it provides option value compared to reconductoring, building new transmission, or building a peaker plant. Batteries can be built in various sizes and can be added to as needs evolve.

(d) congestion alleviation for an area with high renewable energy production. Strategically placed storage near loads and near renewable generation increases the deliverability of renewable energy by shifting generation and load to more desirable times, increasing the overall utilization of transmission and renewable assets while also mitigating congestion.

SAT deployments could show greater system benefit resulting in improved market adoption if the following are considered:

(1) As with other GETs, SAT benefits when planners use a comprehensive grid modeling toolkit that includes 8760 data and considers option value of delaying investment. Without this SAT and other GETs could be undervalued compared to traditional solutions.

(2) Greater value can be realized with advanced control algorithms capable of managing storage system needs consistent with grid needs. This includes balancing the storage system's revenue requirements against the long-term degradation effects of dispatching. Grid models that accurately predict load and generation variances in conjunction with control strategies are also valuable if able to balance daily operational usage of storage while retaining sufficient capacity to respond to grid contingencies.[25]

(3) Accounting systems (through digital systems or meters) can help unlock the full flexibility of storage and its ability to provide diverse grid services from a single device. For example, a SAT system providing peaking capacity for substation upgrade deferral can be used to provide other services in the wholesale market during non-peak times. Combining a transmission service and a wholesale market application is a more efficient use of the SAT resource, but it requires coordination across statutorily separated parts of the grid. Accounting systems that can unlock this business model will create more value for consumers, as wholesale market revenues can defray the cost of the SAT asset.

(4) Storage is not a self-sustaining energy resource and must be charged or discharged to have room to provide grid services. The surrounding grid network must be capable of carrying energy to or from the battery at needed times. Planners should anticipate these flows to ensure performance of the battery, particularly during peak load hours.

23. Twitchell J.B., D. Bhatnagar, S.E. Barrows, and K. Mongrid. 2022. Enabling Principles for Dual Participation by Energy Storage as a Transmission and Market Asset. Richland, WA. Pacific Northwest National Laboratory.

24. AusNet. Ballarat Battery. Accessed on Feb. 21, 2024 at https://www.ausnetservices.com.au/projects-and-innovation/battery-storage/ballarat-battery. Accessed February 9, 2024.

25. California ISO, "Energy Storage Enhancements, State of Charge Implementation – Update" (October 2023), accessed on Feb. 21, 2024 at http://www.caiso.com/InitiativeDocuments/Workshop-Paper-Energy-Storage-Enhancements-State-of-Charge-Implementation-Update-Oct-2-2023.pdf.

(5) SAT can uniquely support other grid technologies and enhance their value. For example, SAT in combination with DLR can help "firm" line carrying capacity across time and provide additional support for contingency events as an "shock-absorber" while energy is redirected onto alternative lines through AFPC technology or re-dispatch.

(6) Follow best practices that early adopters have established for safely siting and integrating battery-based energy storage in highly populated areas. New York provides a good example through their "Energy Storage Guidebook" for local governments and creation of an Inter-agency Fire Safety Working Group.[26]

GETs are established technologies from the standpoint of their proven technological capabilities. However, they have not yet become well-established with robust deployment in the US electrical grid. This section attempted to break down some of the barriers to scale deployment by sharing insights into example strategies for early deployments and by highlighting success factors to consider when scoping projects for greatest success. The next – and final – section considers how policy makers and regulators can help support scale deployment of these technologies.

B. Policy Improvements Supporting GETs

President John F. Kennedy's challenge to the National Aeronautics and Space Administration (NASA) to put a person on the moon in 10 years or less is the stuff of legends. It spawned movies and inspired the concept of a "Moon Shot", or "big, hard problems that demand significant investments of time and money, along with innovative technology and thinking" to solve.[27] Kennedy's challenge called more than 400,000 people together across government and private industry to solve a specific national challenge with focus and at a rapid pace.[28] The billions of dollars spent on the shared objective resulted not only in landing three people on the moon, but also a host of innovations that pushed industry forward.[29]

Decarbonization of our electricity grid presents an equally worthy challenge that needs solving within 10 years and with the participation of hundreds of thousands of people in government and private industry, together. Like the moon shot, we have a clear objective set by the federal government to decarbonize electricity by 2035.[30] Uniquely, we also have demand for decarbonization from many commercial and industrial consumers of energy.[31] And while renewable electricity generation and new generation capacity are growing,[32] the US needs to more than triple current transmission system capacity to meet objectives.[33]

26. NYSERDA, "New York State Battery Energy Storage System Guidebook", accessed on Feb. 21, 2024 at https://www.nyserda.ny.gov/All-Programs/Clean-Energy-Siting-Resources/Battery-Energy-Storage-Guidebook.

27. James Yang, Wired, "Why 'Moon Shot' Has No Place in the 21st Century" (July 16, 2019), accessed on Feb. 19, 2024 at https://www.wired.com/story/apollo-11-moonshot-21st-century/. Yang also notes that challenges like climate change are not as specific or with as "clear-cut finish lines" as Kennedy's moon shot and instead "require ecosystems of innovation." He, therefore, suggests that the climate change moon shot should be a "moon boom".

28. Ibid; see also National Geographic, "The Moon Landing", accessed on Feb. 19, 2024 at https://kids.nationalgeographic.com/history/article/moon-landing.

29. J. Margolis and C. Intagliata, NPR, "Space Spinoffs: The Technology To Reach The Moon Was Put To Use Back On Earth" (July 20, 2019), accessed on Feb. 19, 2024 at https://www.npr.org/2019/07/20/742379987/space-spinoffs-the-technology-to-reach-the-moon-was-put-to-use-back-on-earth.

30. See footnote 3, supra.

31. Listing of RE100 Members, or the more than 400 companies that "have made a commitment to go '100% renewable.'", accessed on Feb. 19, 2024 at https://www.there100.org/re100-members.

32. US Energy Information Administration, "Increased U.S. renewable and natural gas generation likely to reduce summer coal demand" (June 8, 2023), accessed on Feb. 19, 2024 at https://www.eia.gov/todayinenergy/detail.php?id=56760.

33. US DOE, "National Transmission Needs Study" (October 2023), footnote 3, supra; National Renewable Energy Labs, "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035" (2022), accessed Feb. 20, 2024 at https://www.nrel.gov/docs/fy22osti/81644.pdf; US DOE, "Queued Up...But in Need of Transmission (April 2022), accessed Feb. 20, 2024 at https://www.energy.gov/policy/queued-need-transmission.

On October 30, 2023, the DOE published its National Transmission Needs Study (Study), highlighting both the imminent challenges and the opportunities for transmission capacity in the US. The Study reinforces previous DOE findings that the US needs to not only materially grow regional transmission capacity, but also improve interregional transmission by over fivefold.[34] The challenge of building this much transmission capacity quickly is significant, but also presents a transformative opportunity to rebuild the US electrical grid into one that is smart (i.e., digitally enabled), increasingly safe (i.e., reliable, resilient, and decarbonized), and still affordable despite the scale and pace of change.

The GETs discussed in this paper are part of a toolbox of solutions that can be proactively used to build transmission capacity while creating a smart grid that is safe and affordable. DOE has recognized the near-term usefulness of GETs,[35] including efficiency, reliability, and affordability: "GETs deployment can improve the reliability of the existing transmission system and can do so more economically than traditional transmission expansion in certain scenarios because GETs deployment often involves lower capital costs compared with new transmission line construction."[36] DOE has also taken financial action to support GETs: in 2023, it awarded nearly $108.4 million for GETs deployment.[37]

Relatively recent orders issued by FERC also reflect the importance that the agency ascribes to GETs in achieving US renewable energy goals – and that their use is required to ensure just and reasonable energy prices for ratepayers:

> FERC Order 881 requires that transmission owners (TOs) implement ambient-adjusted ratings (AAR) for "both normal and emergency ratings [to] enhance the accuracy of transmission line ratings and ensure just and reasonable wholesale rates."[38] Order 881 also requires market operators to provide systems that allow transmission providers to use dynamic line ratings ("DLR").[39]
>
> FERC Order 2023 requires that TOs incorporate specific alternative transmission technologies into the interconnection study process.[40] According to FERC, these technologies "can provide substantial benefits to optimize the transmission system in specific scenarios because they often can be deployed both more quickly and at lower costs than other network upgrades."[41] FERC further states that "despite these potential benefits, alternative transmission technologies often do not receive the same consideration during generator interconnection processes as other network upgrades."[42]

34. US DOE, "National Transmission Needs Study" (October 30, 2023), footnote 3, supra.
35. US DOE, Interim Webinar Update, "Innovative Grid Deployment: Pathways to Commercial Liftoff" (December 12, 2023), accessed on Feb. 19, 2024 at https://www.youtube.com/watch?v=Ct3L_uMy9ek&ab_channel=U.S.DepartmentofEnergy.
36. US DOE, "National Transmission Needs Study" (October 30, 2023), footnote 3, supra.
37. US DOE Office of Electricity, accessed Feb. 21, 2024 at https://www.energy.gov/oe/articles/us-department-energy-invests-nearly-84-million-advance-grid-enhancing-technologies-gets; US DOE Grid Deployment Office, accessed Feb. 23, 2024 at https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program.
38. Federal Energy Regulatory Commission (FERC). Docket No. RM20-16-000; Order No. 881 (December 2021).
39. Ibid.
40. While FERC's Explainer on the Final Rule suggests that an interconnection customer can request review of technologies, it is AES' understanding that option is not in the Final Rule. See, "Explainer on the Interconnection Final Rule: Improvements to Generator Interconnection Procedures and Agreements", accessed on March 7, 2024 at https://www.ferc.gov/explainer-interconnection-final-rule and FERC. Docket No. RM22-14-000; Order No. 2023 (July 2023).
41. FERC. Docket No. RM22-14-000; Order No. 2023 (July 2023).
42. Ibid; see also "Explainer on the Interconnection Final Rule", accessed on March 7, 2024 at https://www.ferc.gov/explainer-interconnection-final-rule.

Order 2023 excluded DLR from the list of alternative transmission technologies, however a February 2022 Notice of Inquiry (NOI) specific to DLR[43] could still create momentum for deployment of DLR in operations and opportunity for application of generated data sets in planning.[44] FERC recognized in the NOI that DLR has potential advantages over AAR due to more robust data such as wind, cloud cover, and solar heating intensity.[45]

FERC also issued an April 2022 NOPR related to regional transmission planning that includes provisions related to GETs. In the NOPR, FERC proposes to "require that public utility transmission providers in each transmission planning region more fully consider in regional transmission planning and cost allocation processes two specific technologies: the incorporation into transmission facilities of dynamic line ratings and advanced power flow control devices."[46] FERC continues, "We believe that selecting transmission facilities that incorporate dynamic line ratings or advanced power flow control devices in the regional transmission plan for purposes of cost allocation may offer a more efficient or cost-effective alternative to other regional transmission facilities in certain instances."[47]

Congress also introduced two bills in 2023 and one in 2024 that underscore the power of GETs to accelerate decarbonization of the electricity grid.

The Clean Electricity and Transmission Act (CETA) introduced by Rep. Sean Casten (D-IL) and Rep. Mike Levin (D-CA) recognizes the importance of solutions like GETs to upgrading the grid to support interconnection of new energy projects.[48] If enacted, CETA would require that transmission providers consider "deploying grid enhancing assets at the transmission facility or transmission system in addition to, or as a substitute to, carrying out a transmission expansion or addition at the transmission facility or transmission system."[49] The bill also states that "an interconnection customer… may request that the grid enhancing asset that was the subject of such consultation be deployed [by the transmission provider]."[50]

The Building Integrated Grids with Inter-Regional Energy Supply Act (BIG WIRES Act) introduced by Sen. John Hickenlooper (D-CO) also recognizes the importance of GETs in interregional transmission planning. If enacted, the BIG WIRES Act would require each interregional transmission planning region to incorporate GETs, energy efficiency, and demand response into its determination of interregional transfer capability.[51]

The Advancing Grid-Enhancing Technologies Act of 2024 introduced by Sen. Peter Welch (D-VT) (for himself and Sen. Angus S. King Jr. (I-ME)) would require FERC to establish a shared savings incentive to help deployers of GETs receive an improved return on investment while protecting electricity customers' affordability interests.[52]

Why are GETs still facing slow adoption despite specific support from DOE and FERC and supportive signals from Congress? In addition to the education and example deployment barriers addressed previously in this paper, regulators need to (1) ensure that funding and cost-recovery mechanisms encourage use of GETs and (2) create guidance for line owners and operating authorities to take proactive steps to incorporate GETs into system planning processes. The remainder of this section focuses on these two points.

43. FERC. Docket No. Docket No. AD22-5-000 (February 2022).

44. Consistent with the principles stated on page 9 and in footnote 21, supra.

45. FERC. Docket No. Docket No. AD22-5-000 (February 2022).

46. FERC. Docket No. Docket No. RM21-17-000 (April 2022).

47. Ibid.

48. Clean Electricity and Transmission Acceleration Act of 2023. H.R. (2023) at 5 for definition of Grid-Enhancing Assets (GEA) and at 15-21 for GEA use in interconnection of energy projects.

49. Ibid. at 18.

50. Ibid. at 19-20.

51. Building Integrated Grids With Inter-Regional Energy Supply Act. S. 2827 (2023) at 11-12.

52. The Advancing Grid-Enhancing Technologies Act of 2024 (introduced in Senate Mar. 12, 2024), accessed Mar. 28, 2024 at https://www.congress.gov/bill/118th-congress/senate-bill/3918/text/is?overview=closed&format=txt.

1. Ensuring that funding and cost-recovery encourage use of GETs

Ideally policy makers and regulators can provide more "carrots" than "sticks" to encourage adoption of technologies like GETs. Some policy makers may argue that positive incentives (or "carrots") are unnecessary to encourage use of GETs by TOs and grid operators because doing so would be paying grid owners and operators to do what they "should already be doing" – namely, applying available technology to make efficient use of the grid and provide safe, reliable, and affordable energy to customers. Instead, they argue, requirements, compliance, and fines (or "sticks") are what should be used to force recalcitrant grid owners and operators to begin learning about, deploying, and scaling GETs.

While there may be some TOs and grid operators that doggedly refuse to be influenced forward into a modern electrical system, it is more likely that the importance of reliability and a protective bias to controlled, orderly change are the primary root causes of the pace we are seeing in the US regarding GETs deployment. TOs and operators already know certain technologies, how to model them, how they work with the rest of their assets, and where to get them. Asset familiarity allows for more predictable planning, confident operations, and a clear path to cost recovery with regulators. Also, failure to keep the grid up and operating reliably risks its own fines for TOs through outage metrics[53] and can create its own disincentive to accelerated change. Thus, if we allow that TOs and grid operators are not inherently resistant entities but are rationally reacting to existing incentives and disincentives, we can build policies and technology on-ramps that help close the gaps to grid modernization using GETs.

Policy makers may go a step further and recognize that deploying new technologies requires TOs and operators to incur meaningful operational expenses to prepare for reliable deployment of new technologies and that those expenses may not qualify for cost recovery as capital expenses. Consider, for example, the time spent on learning about GETs, their characteristics and

capabilities, how they interact with grid topology and existing assets, how to model them and design benefit measurement methodologies acceptable to regulators. These "overhead" costs to the TOs and operators can seem especially burdensome if resources are otherwise already taxed with grid maintenance and operations, interconnection studies, and anticipating grid impacts from increasing numbers of distributed energy resources.

Some TOs and grid operators will lean into grid modernization regardless of the effort, but if policy makers want scale transformation in the next ten years, they would be wise to explore positive incentives that tip the scales in favor of TOs becoming experts in modern technology like GETs.

One way to bridge the transformation gap may be to implement certain types of performance-based regulation (PBR). PBR is an outcomes-based approach that aims to align utility financial incentives with policy goals, such as decarbonization or grid modernization.[54] This approach is gaining traction as state regulators recognize that the traditional utility framework alone may not specifically encourage utilities to pursue investments and decisions aligned to state policies.[55] Indeed, as of April 2023, at least 17 states have enacted policies that lay the foundation for implementing PBR with their utilities.[56] A regulatory framework governing performance-based rates must be carefully calibrated to avoid disruption to current investments. However, a dynamic regulatory approach focused on outcomes can safeguard existing investments and facilitate a more efficient and rapid expansion of transmission.

53. System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI) are US Distribution System reliability metrics that are closely tracked, and improvements are commonly used as indicators of effective grid investment. See e.g., https://www.eia.gov/electricity/annual/html/epa_11_01.html (accessed Feb. 20, 2024).

54. Wilson, Genelle, et al., "States Move Swiftly on Performance-Based Regulation to Achieve Policy Priorities", RMI (March 2022).

55. Rebane, Kaja, et al., "Making the Clean Energy Transition Affordable: How Totex Ratemaking Could Address Utility Capex Bias in the United States", RMI (July 2022).

56. Shea, Daniel, "Performance-Based Regulation: Harmonizing Electric Utility Priorities and State Policy", National Conference of State Legislatures (April 2023).

There are numerous incentives that can be provided under PBR. These include, operational expense (OPEX) capitalization, performance incentive mechanisms (PIMs), and shared-savings mechanisms (SSM).[57] OPEX capitalization allows utilities to amortize and earn a rate of return on certain operating expenses, creating equal incentives for capital-intensive and capital-light solutions (e.g., software, which can be an essential component of certain GETs).[58] PIMs provide financial rewards or penalties to utilities based on performance in specific areas. These have been used by several states including Illinois, Hawaii, North Carolina, and Minnesota to advance policies related to distributed energy resources, affordability, and equity.[59] SSMs allow utilities and ratepayers to share the savings associated with utilities' implementation of cheaper alternatives to traditional capital investments.[60] States have for decades used SSMs to encourage and reward utility investment in energy efficiency programs.[61]

PBR frameworks could be designed to address the root causes of the slow pace of change characteristic of many TOs and specifically incentivize the outcomes that GETs provide. Enabling utilities to earn a rate of return on targeted OPEX, for example, could provide business incentives to learn about new technologies or help support adoption of software tools like topology optimization. Offering performance incentives focused on timely increase of transmission carrying capacity could encourage use of DLR. Providing utilities with shared savings incentives based on reduced congestion costs could spur the adoption of SAT or APFC. PBR frameworks can have the policy benefit of driving outcomes but should be deployed with a period of transition so that TOs are able to realize the benefits of current investment structures.

Policy makers can also encourage early adoption of technologies like GETs by funding demonstration projects. This is not a new idea as Congress provided for such funding through the DOE and as noted above, DOE has awarded funds to support GETs deployments. For this type of funding to have scale impact, however, it needs to be available on a predictable and on-going basis so TOs have time to educate themselves about GETs, understand their potential deployment in their own grid topology and regulatory environment, and then apply for financial support in early deployments. This learning cycle may partially explain why there have been limited submissions by TOs requesting support from DOE for GETs and of the $108.4 million awarded to date for GETs, not all went to support TO initiatives.[62] It may be challenging to bridge the learning gap in time for significant allocation of remaining DOE funds under the Bipartisan Infrastructure Law (BIL) to go to GETs deployments, but it may yet be possible if TOs and the DOE broadly share learnings from early deployments that do take place.

State regulators also have a pivotal role in breaking down deployment barriers. Although GETs have deployment proof points in certain states, regions, and countries, TOs and regulators may require localized validation before widely deploying those same technologies on their systems. The Connecticut (CT) Public Utilities Regulatory Authority's (PURA) Innovative Energy Solutions (IES) Program (approved in March 2022) advances the state's goal of an equitable, modern, decarbonized grid through the deployment of "high-value project solutions that might not otherwise be possible or expedient within the current regulatory environment."[63] The five-year program provides CT utilities with a framework and cost recovery mechanism

57. Rebane, Kaja, et al., "Making the Clean Energy Transition Affordable: How Totex Ratemaking Could Address Utility Capex Bias in the United States", RMI (July 2022).

58. Ibid.

59. Shenot, John, et al., "Performance-Based Regulation (PBR): An Overview", presentation to Public Service Commission of Wisconsin, The Regulatory Assistance Program (January 2022).

60. Rebane, Kaja, et al., "Making the Clean Energy Transition Affordable", footnote 57, supra.

61. National Action Plan for Energy Efficiency, "Aligning Utility Incentives with Investment in Energy Efficiency", prepared by Val R. Jensen, ICF International (December 2007).

62. DOE Grid Deployment Office, "Grid Resilience and Innovation Partnerships (GRIP) Program Projects", accessed on Feb. 21, 2024 at https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program-projects. It is notable that in 2023 the DOE's Grid Deployment Office awarded nearly $3.5 billion in grants as part of its Grid Resilience and Innovation Partnership (GRIP) and three percent ($100 million) funded projects specifically targeting GETs.

63. State of Connecticut Public Utilities Regulatory Authority. Docket No. 17-12-03RE05 (March 2022).

to deploy innovative pilot programs, technologies, products, and services in collaboration with third-party product innovators.[64] An independent consultant evaluates initiatives at the end of the program, and those that demonstrate ratepayer benefits are considered for wider deployment.[65]

Regardless of the specific incentive methodologies that policy makers and regulators apply, it is important to offer lasting, objective driven incentives for both early deployments of technology and early scaling. Lessons learned from early projects should be collected and communicated with an appropriate level of detail so that TOs and grid operators can learn from the experience of others. Entities like the DOE and state regulatory authorities can help in this regard. However, lessons learned do not replace localized learning as the unique characteristics of a network – e.g., size, topology, asset health, weather risks, customer profiles – can have meaningful impact on the solutions selected and benefits gained.

2. Encouraging proactive incorporation of GETs in system planning and operations

If policy makers and regulators help address the essential barriers to early technology adoption, TOs and grid operators will be in a better position to comply with any on-going requirements to evaluate and apply technologies like GETs in system planning and operations. Reticent line owners and transmission authorities could be required through law or regulation to take proactive steps to evaluate and incorporate GETs – where beneficial – in operations, system planning processes, as operational solutions to right-size network upgrade requirements, and even through routine system maintenance and upgrade.

One approach to this requirement could be inspired by the "Best Available Technology" (BAT) concept introduced by the Clean Water Act (CWA) "to progress the nation's goal of eliminating the discharge of pollutants into US waters"[66] and effected by the US Environmental Protection Agency (EPA), prominent for its role in emission reduction and efficient power generation.[67] BAT emphasizes the adoption of the most effective technological solutions to address specific challenges, while being economically viable and feasible to implement.[68] Technology is "economically achievable" if its costs can be reasonably borne by the industry and "available" even if it has only been used in pilot demonstrations.[69] This framework could support use of GETs where timely access to affordable grid carrying capacity improvements are needed.

64. Ibid.

65. Ibid. There is a $25 million budget to provide TOs support for early deployments while projects that move to later stages of development are eligible for cost recovery.

66. 33 U.S.C. § 1311(b)(2)(A).

67. US Environmental Protection Agency, Best Available Technology Economically Achievable (BAT) Effluent Guidelines, accessed Feb. 20, 2024 at https://www.epa.gov/eg/learn-about-effluent-guidelines.

68. Ibid.

69. Comments of Environmental Integrity Project, et al. Docket No. EPA–HQ–OW– 2009–0819; EPA–HQ–RCRA–2013–0209 (June 2013).

A key element of BAT is that it inherently evolves over time. Whereas regulations like FERC Order 2023 prescribe the use of technologies deemed appropriate at a specific point in time, BAT continually evolves to incorporate new technologies, new learnings, and new industry perspectives. The fluid and potentially subjective nature of BAT, however, necessitates that policy makers and regulators grant ultimate decision-making authority of what constitutes BAT to an authoritative entity—perhaps the DOE. Without this delegation of authority, it is possible that BAT regulation would be delayed by competing stakeholder views. Nonetheless, any decision-making authority should incorporate diverse stakeholder input, thoroughly evaluate the results of demonstration projects, and reasonably account for differences among networks.

A second but similar policy parallel is pursuing least cost diverse generation through All-Source Request for Proposals (RFPs).[70] These polices share the foundational principle to source and deploy the most effective solutions available without being constrained by certain types of technology. In essence, identifying the needs of the grid and its customers and then procuring the best solution to meet those needs. A benefit of this standard is that it evolves with technological advancements and ensures the transmission sector continually strives for better performance and efficiency. This paragraph does not imply that All-Source needs-based procurement processes are appropriate to all TO purchasing decisions, but where there is a grid need that objectively could be met by multiple technology solutions, TOs may lean on technology companies to demonstrate in an RFP process how their GET (or other technology) meets the specific grid needs.

The policies discussed in this section could meaningfully accelerate the deployment of GETs and help the US achieve its ambitious grid decarbonization goals. Policy makers and regulators have made some progress in laying the foundation for the use of technology like GETs in operations and interconnection. However, further advances require incentives for learning about, deploying, and scaling new and underused technologies. Once barriers to scale use are addressed, on-going use can be supported through methodologies analogous to BAT or All-Source Procurement.

Grid transformation is not likely without policy reform. Like the physical grid itself, many laws and regulations governing the grid are relics of an era in which large, centralized thermal generation served predictable load. It is unrealistic to expect most TOs and grid operators to bear the cost of learning, inefficiency, and process change, and bear the risk of grid reliability without support and incentives that bridge the gap to accelerated adoption. Failure to do so will risk the opportunity of having TOs and grid operators at the table as key coalition members, ready to build the smart, reliable, and affordable grid that customers need.

70. See e.g., John D. Wilson, et al., “Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement” (April 2020), accessed Feb. 20, 2024 at https://energyinnovation.org/wp-content/uploads/2020/04/All-Source-Utility-Electricity-Generation-Procurement-Best-Practices.pdf.

Conclusion

The US electrical grid is in a period of dramatic change. Modern expectation for transformation is that it should happen quickly – responsively. Society values the capabilities that an increasingly digital and dynamic ecosystem of technologies brings and wants more of that convenience, customization, and connection. But change needs to be managed, efficient, affordable, and equitable.

Customer expectations for change – as this is why we have an electrical grid (to provide energy to customers) – come along with (a) increasing demand for energy, (b) changes in the number, type, and location of generating and consuming assets, and (c) growing proliferation of digital assets and capabilities on the grid. These catalysts for change require us to build a modern grid that is smart, dynamic, and flexible while delivering the energy customers need in a manner that is safe, reliable, and affordable.

To achieve this level of transformation at the pace of change needed to address increasing weather, cyber, and climate risks, we need to tackle several key challenges without further delay. We need to alleviate burdened interconnection processes, improve transmission capacity, modernize planning and operations processes, and make the most of grid assets (existing and new). GETs are essential tools in the toolbox of modern technological solutions to achieve the complex but essential objectives of the evolving energy ecosystem.