# Building a Better Grid:

## HOW GRID-ENHANCING TECHNOLOGIES COMPLEMENT TRANSMISSION BUILDOUTS

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## NOTICE

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# Executive Summary

> *Without transmission, our clean energy mission is stuck in neutral.*
> (Jennifer Granholm, Secretary of Energy).

The U.S. energy industry is going through a massive transition, partially driven by decarbonization initiatives that significantly increase renewable generation resources. The preferred locations for many of these new resources are often in remote areas far from consumption. The emergence of clusters of these remote resources inevitably leads to the need for more transmission.

Various studies, including the draft study titled "National Transmission Needs Study" released from the U.S. Department of Energy ("DOE") in February 2023, indicate an unprecedented need for transmission buildouts that effectively double or triple the existing transmission grid over the next 10 to 20 years. This equates to, at a minimum, tripling the level of transmission investment of today (estimated to be ~$25 billion a year) for the foreseeable future. There will likely be challenges, including the physical ability (e.g., logistical challenges, including supply chain and human resources) and economic feasibility (e.g., impact on rates), especially if the focus is limited to the traditional transmission projects (or "wires options").[1]

When developing transmission expansion strategies to achieve these ambitious goals, Grid-Enhancing Technologies ("GETs") should be part of the solution.[2] These technologies represent a new model for increasing grid infrastructure by unlocking additional capacity on the existing transmission system, and can be developed much faster and in a modular least-regrets manner at a small fraction of the cost of traditional transmission projects. Furthermore, they complement transmission buildouts by enhancing the utility of transmission infrastructure instead of eliminating or replacing it. GETs also magnify the capabilities provided by and the cost effectiveness of new transmission investments. The complementary benefits of GETs emerge ***before*** traditional transmission projects are developed, activate ***during*** construction of the transmission projects, and continue ***after*** the newly developed transmission projects are put in

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1 Most of these studies focused on the traditional "wires options" for building transmission, and while some recognize non-wires options, including Grid-Enhancing Technologies ("GETs"), they are not considered as part of the solution.

2 GETs considered in this white paper are limited to Dynamic Line Ratings ("DLR"), Flexible Alternating Current Transmission Systems ("FACTS") for flow control, and Topology Control.

service. This white paper illustrates these effects through actual GETs examples, and quantifies, where possible, the complementary benefits in monetary terms.

**The benefits of GETs start _before_ traditional transmission projects are developed.** Planning for and building new transmission typically takes five to ten years or longer. Many GETs can be installed in under a year to alleviate congestion and help integrate more resources before the new transmission projects are put in place. Furthermore, examples discussed in this white paper demonstrate that the payback period on GETs investment are minuscule, measured in months, rather than years. GETs are scalable and their deployments are reversible—unlike other capital-heavy investments, they can be removed (and relocated) if the need is no longer there. The portability, scalability, reversibility, and comparatively smaller investment size of GETs provide flexibility to address transmission issues _before_ new transmission is built. This option is particularly effective when there is uncertainty about the future, for example with the pace of load growth, or changes in flow patterns. Examples of GETs deployment include Topology Control and Dynamic Line Ratings ("DLR") to reduce congestion, and multiple GETs [DLR, Topology Control, and Flexible Alternating Current Transmission Systems ("FACTS") devices for flow control] at a regional level to integrate more renewables. In addition, GETs that provide immediate solutions to existing grid issues could allow more time to develop traditional transmission solutions, and simultaneously delay capital investments.

**The complementary benefits of GETs continue _during_ the construction of traditional transmission solutions by reducing the impact of outages or avoiding outages entirely.** Installing GETs as the solution (in particular, DLR and Topology Control) often does not require transmission outages, or only require a shorter outage. When the preferred solution is to build new (or reconductor existing) transmission, GETs could help alleviate the impact of transmission outages needed for upgrading existing lines and interconnecting the new line(s) into the existing grid. Examples of GETs mitigating congestion or reducing outage needs discussed in this white paper include Topology Control and FACTS devices for flow control. During the outage planning process, Topology Control software can be used to identify options that minimize the impact of outages.

**GETs can further help increase the value of new traditional transmission projects _after_ they are put in service.** For example, GETs can increase the utilization of the existing system [which will include the newly added line(s)], hence increasing the Benefit to Cost ratio of any given transmission project.[3] This could allow for more transmission projects to pass the selection threshold (the Benefit to Cost ratio is one of the key metrics used), potentially increasing the number of validated transmission projects. Previous analysis of the Southwest Power Pool ("SPP") system has shown that GETs will increase the utilization level of existing 345 kV lines by 16%. GETs can also be deployed after the fact to mitigate unanticipated consequences triggered by the new line(s). For example, if energizing the new line(s) results in unintended congestion, such as those on the underlying lower voltage lines, GETs could be quickly deployed to address it. Finally, GETs can contribute to system resiliency under extreme conditions as they provide means for situational awareness and operational remedies. Examples included in this white paper are for severe weather conditions.

The complementary nature of GETs will help the unprecedented transmission buildout in multiple ways. *First*, combining GETs and transmission **enhances the value of the transmission projects**. Previous analysis of the SPP system shows GETs increasing the utilization level of 345 kV lines by 16%. This allows for a larger pool of transmission projects to pass the Benefit to Cost ratio threshold and be considered as part of the solution. *Second*, combining GETs and transmission will **reduce the overall amount of transmission needed and contribute to a lower overall cost of the transmission buildout**, as this combination could significantly increase the amount of renewable integration—the aforementioned SPP analysis shows adding GETs doubled the amount of renewables integrated, thereby suggesting transmission needs could be reduced by half. The same SPP analysis indicated investment cost reduction of more than 45%. *Third*, deployment of GETs nationwide **will reduce congestion costs**, which exceeded $13 billion in 2021. This may become even more important as the prospect of a historic buildout of new transmission (and upgrades) over the next 10 to 20 years implies a significant increase in congestion during construction-related outages. Examples reviewed in this white paper suggests 40% or more of congestion can be mitigated by GETs. Congestion mitigation alone, even if partial, will likely pay for the GETs. Mitigation of outage related congestion, in particular those that occur *during* construction of new transmission projects, will further facilitate new transmission projects because their Benefit to Cost ratio improves. And *fourth*, the combination of lower costs and deployment flexibility (scalability and reversibility) of GETs **reduces the risks faced by**

[3] Transmission needs documented in various studies, including DOE's National Transmission Needs draft report, are typically based on economic models. The needs identified represent the transmission buildout that gets to the most cost-effective electricity system. Therefore, a higher transmission cost (i.e., higher than assumed) will lead to lower buildouts as the optimal solution. If transmission costs are lower, the optimal solution will recommend more transmission. Since GETs will reduce the cost of adding transmission, they will more often make transmission the more cost effective solution, and the economic models would suggest a solution with higher levels of transmission.

**transmission developers and owners**, especially during the dynamic transition period we are facing.

Overall, it is prudent to consider GETs as part of the solution to two key challenges of the energy transition: the physical ability of the system (e.g., logistical challenges, including supply chain and human resources) and economics of the transition (e.g., impact on rates). Incorporating GETs into transmission expansion will also align well with the recent Notice of Proposed Rulemaking ("NOPR") titled "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" (RM21-17-000) issued on April 2022 by the Federal Energy Regulatory Commission ("FERC"), which proposes to require that public utility transmission providers more fully consider GETs in their planning.

> *"We have to figure out as regulators at both the state and federal level how we can help utilities take advantage of this opportunity. It's real and it's exciting - we can take these big old clunky not-smart wires and turn them into more dynamic assets on the system. It will save customers money, and now is the time to do it as we are thinking about larger investments in bigger, more expensive backbone transmission."*
> [Allison Clements, FERC Commissioner, at the 2022 National Association of Regulatory Utility Commissioners ("NARUC") Annual Meeting and Education Conference]

# I. Introduction

The U.S. energy industry is going through a massive transition, partially driven by decarbonization initiatives that often trigger and determine targets for increasing renewable generation resources, along with the economic competitiveness of these resources (over other resources.)[4,5] Large-scale (i.e., utility-scale) renewable resources typically have lower costs than those of smaller scale (i.e., distributed energy resources, such as rooftop solar panels) and are usually built in remote areas. The emergence of clusters of remote resources, combined with load growth (which could also accelerate with decarbonization initiatives electrifying load), inevitably leads to the need for more transmission.

4 As of the end of 2022, 29 states and Washington DC had Renewable Portfolio Standards and six states had Clean Energy Standards.

5 Today, renewable generation resources are best represented by wind and solar, though the makeup is expected to evolve as new resources emerge.

The exponential growth of planned new renewable resources has exacerbated the need for more transmission infrastructure. The recent study from the Lawrence Berkeley National Laboratory ("LBNL") titled "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2022" ("LBNL Queued Up Study") suggests there are more than 10,000 projects adding up to greater than 2,000 GW of new resources (1,350 GW of generation and 680 GW of storage) awaiting interconnection to the transmission grid.[6] This includes nearly 950 GW of solar and 300 GW of wind, which when combined, roughly equals the installed nameplate capacity of the entire U.S. power plant fleet today.

Various studies estimate the U.S. will need to double or even triple its electric transmission capacity within the next few decades as the nation shifts toward a grid dominated by variable renewable energy resources.[7]

> *"The current power grid took 150 years to build. Now, to get to net-zero emissions by 2050, we have to build that amount of transmission again in the next 15 years and then build that much more again in the 15 years after that. It's a huge amount of change."*
> (Jesse Jenkins , Princeton University study coauthor)

A Princeton University study titled "Net-Zero America: Potential Pathways, Infrastructure, and Impacts" looks at five different pathways for the U.S. to achieve net-zero emissions and envisions expanding the U.S. electric transmission grid 60% by 2030.[8] The study further suggests the U.S. grid may need to triple in size by midcentury.

The National Renewable Energy Laboratory ("NREL") study titled "North American Renewable Integration Study" estimates that the U.S. is projected to need roughly two to three times more transmission delivery capacity to accommodate a surge in renewable energy development amid efforts to fully electrify the power, transportation and industrial sectors.[9]

Similarly, NREL finds in its "Interconnections Seam Study" the need for 40,000 to 60,000 GW-miles of alternating current ("AC") and up to 63,000 GW-miles of direct current ("DC")

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6 Lawrence Livermore National Laboratory, [Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2022](), April 2023.

7 Most of these studies focused on the traditional "wires options" for building transmission, and while some recognize non-wires options, including Grid-Enhancing Technologies ("GETs"), they are not considered as part of the solution.

8 Study is available at: https://netzeroamerica.princeton.edu/?explorer=year&state=national&table=2020&limit=200

9 Study is available at: https://www.nrel.gov/analysis/naris.html

transmission to be added—by comparison, the U.S. has approximately 150,000 GW-miles in operation today.[10]

The Massachusetts Institute of Technology ("MIT") study titled "The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System" suggests a roughly 90% increase in transmission capacity. The authors conclude this is in line with other studies showing that roughly a doubling in installed transmission capacity is required to be cost-optimal for electricity decarbonization in the U.S. and the European Union ("EU").[11]

The February 2023 draft study released from the U.S. Department of Energy ("DOE") titled "National Transmission Needs Study" estimates that the transmission system will need to grow by 57% by 2035 (compared to today) to comply with enacted policies (including the bipartisan Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022).[12] This suggests transmission needs to grow by almost 5% every year through 2035. DOE estimates that a higher load growth (driven by load electrification) scenario will require to effectively double today's transmission by 2040. This scenario would require an average growth of slightly above 5% every year through 2040. In addition to these new needs, a large share of the existing transmission facilities are approaching the end of their economic life and will require upgrades, if not replacement. This compounds the need for even more transmission.

> *"Accelerating our transition to a renewable energy economy necessitates significant investment in our nation's antiquated transmission infrastructure."*
> (Greg Wetstone, CEO, American Council on Renewable Energy)

And yet, recent investment in transmission has been far below this level. The North America Electric Reliability Corporation ("NERC") estimates in its Transmission Availability Data System ("TADS") data and State of Reliability Reports that the total transmission system (for 100 kV and larger) of today is about 500,000 miles.[13] Comparing the 2021 and 2022 publications of the State of Reliability Report suggests the annual transmission addition (for 100 kV and larger) to be around 7,500 miles, or 1.5% of today's existing 500,000 miles. Comparing the 2015 and 2021

10 Study is available at: https://cleanenergygrid.org/wp-content/uploads/2018/08/NREL-seams-transgridx-2018.pdf, https://www.nrel.gov/analysis/seams.html

11 Study is available at: https://www.cell.com/joule/fulltext/S2542-4351(20)30557-2?_returnURL=https://linkinghub.elsevier.com/retrieve/pii/S2542435120305572?showall%3Dtrue

12 Department of Energy, Draft National Transmission Needs Study, February 2023.

13 2022 State of Reliability Report shows 511,099 miles of lines rated at >100 kV. The report is available at: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf. The 2021 State of Reliability Report shows 503,551 miles of lines rated >100 kV. The report is available at: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2021.pdf.
The TADS data is available at: https://www.nerc.com/pa/RAPA/tads/Pages/default.aspx ?

vintages of the TADS data suggests the annual transmission addition (for 100 kV and larger) to be less than 9,000 miles, or 1.8% of the total transmission that exists today. NREL estimates in its "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035" report that in 2013, about 4,100 miles of transmission above 230 kV were completed, and that this was the most in a single year between 2010 and 2020. The TADS data reveals that about half of all transmission additions are at voltage levels lower than 200 kV. Combining the NREL observation and TADS data suggests roughly 8,000 miles of new additions annually, or 1.6% of the total transmission that exists today. Finally, NERC's Long-Term Reliability Assessment ("LTRA") projects approximately 15,500 miles of new transmission to be built over the next ten years. This indicates an average annual increase in the size of the bulk transmission system of 0.3%.[14] In all cases, in order for the pace of transmission buildout to approach the aforementioned 5% level, the buildout needs to be three times of what we observe today.[15] The magnitude and pace, further combined with other logistical limitations (e.g., manufacturing of equipment, and skilled labor) and regulatory policy implications (e.g., environmental justice issues, capping increase in electricity rates and protecting consumers) that may exist, make the task of expanding transmission capacity even more challenging, especially if the solution is limited to the "wires options" ("traditional transmission").

In addition, uncertainty surrounding transmission buildouts has increased. Renewable and storage assets can be built quite quickly, sometimes in less than a year. The aforementioned LBNL Queued Up Study shows that over 60% of the projects [73% of solar (695 GW), 69% of storage (472 GW) and 48% of wind (145 GW), adding up to 1,262 GW of total capacity in the generation interconnection queue] have proposed online dates by end of 2025. Many projects are not expected to realize—LBNL discusses historical observations showing that only 21% of all projects (14% of capacity) proposed between 2007 and 2020 reached commercial operation by the end of 2022 while 72% of all projects were withdrawn.[16] Furthermore, flow patterns observed are generally expected to become more complex and variable as more renewable resources are built and load profiles change with energy efficiency, demand response, distributed energy resources,

[14] NERC's 2022 LTRA shows a cumulative level of 15,495 miles of transmission (>100 kV) in construction or stages of development for the next 10-years, and suggests that level to be near averages of the past five years. The report is available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf,

[15] Increasing transmission at the rate of 5% a year will grow the transmission system by 50% over the next ten years, and double the transmission system over the next 20 years. This is not enough to double today's transmission by 2040, as the DOE National Transmission Needs Study suggest would be needed under high load growth.

[16] This rate was even lower for wind (at 20%) and solar (at 14%).

electrification, and further diversified consumer behaviors. This change contributes to additional uncertainty and the potential risk of stranded assets for transmission owners.

When developing strategies to address the urgently needed transmission capacity expansion, Grid Enhancing Technologies ("GETs") should be considered as part of the solution.[17,18] First, these technologies can increase transfer capabilities of the existing grid. When compared to the traditional transmission buildout options, GETs—taking advantage of recent technology improvements in electronics, communications, computational power, and optimization algorithms—can be implemented much faster for a small fraction of the cost. And they are portable, making the changes scalable and reversible. If deploying GETs at a given location did not work as anticipated, it could be removed—akin to a portable Global Positioning System ("GPS") that you can replace without impacting the function of the car. Second, these technologies are complementary to the traditional transmission investments—they can be used to enhance the capability of the existing grid as well as magnify the capabilities provided by and the cost effectiveness of new transmission investments. GETs, as their name suggests, enhance transmission, not replace (or eliminate) it. In fact, GETs offer complementary benefits at all stages of transmission planning, construction, and operations. Third, utilizing GETs as part of the solution could help alleviate some of the other project risks and uncertainties (e.g., scheduling, logistics, and budget) indicated above.

# II. Complementary Benefits of GETs at Different Stages of Transmission Expansion

Expanding transmission capacity is akin to expanding roads. When there is congestion (traffic), adding new transmission (roads) could help alleviate that congestion. However, similar to the network of roads, transmission capacity does not rely solely on the physical transfer capability of the individual lines added. Rather, it varies by where and how the new lines are added, and often

[17] The Federal Energy Regulatory Commission ("FERC"), in its Notice of Proposed Rulemaking ("NOPR") "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" (RM21-17-000, issued April 22, 2022), discusses GETs. Specifically, the NOPR proposes to require that public utility transmission providers more fully consider dynamic line ratings and advanced power flow control devices in regional transmission planning.

[18] Federal Power Act Section 219 (b) 3 added by the Energy Policy Act of 2005 ("EPAct") specifically points to "encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities."

depends on the underlying system (i.e., other system elements) to accommodate the new transfers. Just as a poorly designed highway off-ramp may cause unintended congestion on the highway, transmission transfer capability will also depend on where and how new lines are connected to the rest of the system—this is the topology of the transmission network (including the points of injection and withdrawal of energy). Both the transfer capability of lines (and other components of the grid) and network topology determine how, where, and the quantity of the power flows.[19] Many GETs are built on either of two applications to increase transfer capability: one that explores enhanced and flexible application of the pre-determined transfer capability; and the other that focuses on flexible and dynamic control of transmission systems.[20]

Examples of GETs discussed in this white paper are limited to three representative technologies, namely Dynamic line rating ("DLR"), Flexible Alternating Current Transmission Systems ("FACTS"), and Transmission Topology Control. DLR is a representative application that tries to better address the individual line's transfer capability. FACTS—a common category of power-electronics-based devices that allow for flexible and dynamic control of transmission systems—are examples of hardware solutions focusing on controlling the flow, and is functionally similar to Phase Shifting Transformers ("PST"), also known as Phase Angle Regulators ("PAR"). Transmission Topology Control is an elegant software alternative to these flow control hardware—it controls the flow by adjusting the system topology (for example, by opening or closing circuit breakers) and hence changing the flow distribution that is defined by Kirchhoff's Law to achieve operational objectives. There are various other technologies—many which have been shown to be robust and effective—that this white paper does not discuss and could be considered as well.

The comparative advantages of GETs include their portability and scalability (i.e., they can be added in phases without committing to a larger project), speed to deploy (i.e., they can be put into service much faster), and lower costs (i.e., they can be deployed often for a small fraction of the cost). GETs rarely replace transmission, rather, they enhance transmission—and their complementary benefits start *before* the traditional transmission projects are being developed, continue *during* construction of the transmission projects, and *after* the newly developed transmission projects are put in service.[21] The remainder of this section discusses the

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19 The mainstream practice of transmission planning today is to maintain the flows within pre-determined line limits, which are often developed under a very conservative set of assumptions, and assume the topology is fixed.

20 Other technologies that the authors are aware and some consider as GETs include (but not limited to) batteries and storage devices, and advanced cables and conductors.

21 Exceptions may include GETs deployment in occasions when reconductoring, or replacing lines are difficult, as sometimes observed on radial lines, transmission paths with limited rights of ways, or geographical consideration, such as terrains that make construction difficult and expensive.

complementary benefits GETs can provide for these three periods. GETs benefits under extreme conditions (provided through situational awareness and operational remedies) are discussed later in *Section III. B. GETs Under Severe Conditions*.

## A. Before Construction

Building new transmission typically takes five to ten years or longer. Many GETs can be installed in under a year to quickly help address existing or emerging issues, including congestion, *before* the new transmission projects are put in place. Furthermore, GETs are reversible—unlike other capital-heavy investments, they can be removed or relocated easily as needed. The portability, scalability, reversibility, and comparatively smaller investment size of GETs provide versatility to address transmission issues before new transmission is built. Some of the remedies could be planned as (or later become) permanent solutions. This option is particularly effective when there is uncertainty about the future, for example with the pace of load growth, or changes in flow pattern. In addition, GETs that are used to immediately ease existing grid issues could allow for delaying the traditional transmission solution development, which leads to more time to develop such projects and defers capital investments.

We discuss six examples of GETs proactively addressing transmission issues (e.g., alleviate congestion and integrate larger amounts of renewable resources) before the new transmission projects aimed to address the issues are put in place here.

### CASE 1: TOPOLOGY CONTROL FOR SPP CONSTRAINTS

In 2022, NewGrid (a Topology Control software vendor) studied several SPP constraints and evaluated potential reconfiguration options. These constraints include the Osage to Webb Tap 138 kV line (for the loss of Sooner to Cleveland 345 kV line) and the Cimarron 345/138 kV transformer. The Osage to Webb Tap 138 kV line has been very heavily loaded and the constraint was breaching or binding in over 28% of all market intervals in April 2022. SPP had identified the constraint as "overlapping Reliability and Economic need" in its 2020 Integrated Transmission Planning ("ITP") Assessment Report.[22] A reconfiguration enabled 10% to 20% of increased flow on the Osage to Webb Tap 138 kV constraint. The Cimarron 345/138 kV transformer was breaching or binding over 5% of all market intervals in April 2022, leading to increased costs for load in Oklahoma City. SPP identified this constraint as the top "Operational Need" in the 2020 ITP Assessment Report. Reconfiguration reliably enabled 13%

[22] SPP, 2020 Integrated Transmission Planning Assessment Report, October 27, 2020, p. 66. Available at: https://www.spp.org/documents/63434/2020%20integrated%20transmission%20plan%20report%20v1.0.pdf

to 23% increased constraint throughput under congested conditions. SPP has implemented the reconfiguration solution identified for the Cimarron 345/138 kV transformer at times to prevent severe overloads of this constraint during summer peak (the constraint had an average real-time congestion shadow price of $80/MWh in 2022, binding more than 20% of all hours, adding to more than $30 million in annual real-time congestion costs).[23]

### CASE 2: TOPOLOGY CONTROL FOR MISO CONSTRAINTS

NewGrid also addressed the constraint on the Lime Creek to Barton 161 kV line (for the loss of Quinn to Blackhawk 345 kV line), which has been a standing constraint recognized by the Midcontinent Independent System Operator ("MISO") for past years. NewGrid identified, and MISO implemented a reconfiguration of the Quinn 345 kV bus in May 2022. After this mitigation solution, between June 2022 and February 2023, this constraint bound only about 108 hours. Analysis indicates that over the same period, the constraint would have been binding more than 220 hours without the reconfiguration, suggesting a mitigation rate of over 50%.

### CASE 3: TOPOLOGY CONTROL FOR ALLIANT ENERGY

On a larger, regional scale, NewGrid has been conducting a topology optimization pilot with Alliant Energy. The pilot identifies and analyzes beneficial reconfigurations, and requests and tracks their implementation to mitigate congestion costs affecting Alliant's customers. Interim study findings for congestion between October 2021 and May 2022 suggest that over 40% of the realized congestion costs (summing to more than $100 million for this period) could be avoided through reconfiguration.[24] Reconfigurations implemented so far using the ad-hoc request process have yielded about one fifth of the potential savings. With the implementation of the MISO reconfiguration request process, it is estimated that the relative impacts will increase.[25]

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[23] P. A. Ruiz, P. C. Ochoa, M. Myhre, R. Donaldson, X. Li, Congestion and Overload Mitigation using Optimal Transmission Reconfigurations – Experience in MISO and SPP, FERC Tech. Conf. on Increasing Market and Planning Efficiency through Improved Software (Docket No. AD10-12-013) Washington, DC, June 23, 2022. Available at: https://www.ferc.gov/media/congestion-and-overload-mitigation-using-optimal-transmission-reconfigurations-experience

[24] The impacts were calculated ex-post based on analyses of state estimator cases published by MISO and of historical market data. *Id.*, p. 16.

[25] Currently there are no established processes for requesting reconfigurations. Some of the solutions have not been requested due to the lack of such process.

Reconfiguration solutions discussed in the three examples above are identified through a Topology Optimization software, which has very small incremental costs for additional usage. NewGrid, based on discussions with transmission owners, switching device manufacturers, and service providers, estimate the actual cost of reconfiguration is around $100 per switching action. Thereby, the cost of applying Topology Control is minuscule, when compared to the congestion cost savings measured in millions of dollars.

### CASE 4: DLR FOR PPL 230 KV LINES

Ampacimon (a DLR vendor) installed DLR systems on three 230 kV lines (Harwood to Susquehanna lines #1 & #2 and Juniata to Cumberland line) in the PPL territory as a proactive remedy to avoid $23.5 million of annual congestion costs projected in 2025.[26] DLR, which provides 20% capacity gain above static ratings for 90% of the time (and cleared PJM's market efficiency window for the application), was selected because of the lower costs (less than $1 million for DLR compared to $20 million for reconductoring, and $40 to $60 million for rebuilding transmission), and speed of installation (less than 1 year with no outages for DLR compared to 2 to 3 years with extended outages for reconductoring, and 3 to 5 years with extended outages for rebuilding transmission). The investment cost ($1 million) is significantly smaller, representing only about 4% to 5% of the estimated congestion cost (of $23.5 million) for a single year.

### CASE 5: DLR FOR UPSTATE NEW YORK

LineVision (a DLR vendor) installed DLR systems on two double-circuit 115kV lines in upstate New York, where the utility is experiencing strong growth in wind and solar generation. This DLR project, along with five miles of circuit rebuilds, is projected to reduce renewables curtailments by over 350 MW while further increasing the transfer capacity of the circuits by an additional 190 MW. The DLR project will avoid the need to rebuild 26 miles of transmission lines. With an estimated cost of $3.2 million, the project budget is less than the average cost of rebuilding just a single mile of a 115 kV line in the area, and will provide substantial cost savings for rate payers.

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26 PPL Electric Utilities (H. Lehmann, E. Rosenberger, and B. Elko), *Dynamic Line Ratings Operations Integration*, presented at PJM DLR Task Force Meeting, December 12, 2022 at https://www2.pjm.com/-/media/committees-groups/task-forces/dlrtf/2022/20221212/20221216-item-04---ppl-dlr-presentation.ashx

These examples demonstrate the speed and cost-effectiveness of DLR systems. Investment can be recouped within months, if not weeks. DLR further increases system awareness for the operators, which is a benefit that is not quantified.

### CASE 6: GETS FOR INTEGRATING MORE RENEWABLES IN SPP

In 2021, The Brattle Group released a study titled “Unlocking the Queue” that discussed how GETs (DLR, Topology Control, and FACTS together) can integrate twice the amount of renewables in the Kansas and Oklahoma region of SPP.[27] Observing over 9,000 MW of renewable projects that had already signed Interconnection Agreements (as of 2020) but had yet to proceed forward, the study analyzed how much of those projects could be integrated by 2025 (accounting for system changes, including planned transmission upgrades of approximately $1 billion) with and without GETs. The year 2025 was selected as it is not far enough to build significant transmission to accommodate more renewables. The case with GETs showed that over 5,200 MW can be integrated, while the case without GETS enabled less than 2,600 MW. The study also showed that the production cost benefits by these renewables alone would pay for the GETs investment costs of $90 million in six months.[28]

The six examples above illustrates how GETs can proactively address the pressing concerns (e.g., alleviate congestion and integrate larger amounts of renewable resources) before the new transmission projects aimed to address the issues are put in place. In addition, GETs that provide immediate solutions to existing grid issues could push back the traditional transmission solution development and provide benefits of allowing for more time to develop such projects and delayed capital investments. These benefits are not quantified in this white paper.

## B. During Construction

GETs can minimize impact *during* construction by avoiding an outage altogether, or preventing congestion caused by transmission outages that occur while interconnecting the new projects. Topology Control software could also be used to identify the least impactful outage options.

The aforementioned DLR case for PPL (CASE 4: DLR FOR PPL 230 KV LINES) is an example where using GETs avoids any transmission outages associated with the upgrades. Where GETs

[27] The study is available at: https://watt-transmission.org/unlocking-the-queue/

[28] Other benefits identified in the study included carbon emission reduction and local tax and jobs. Expanded nation-wide, the study showed that GETs (with a $2.7 billion one-time investment) could lead to over $5 billion dollars in annual savings while reducing more carbon than those of all new cars sold in the US.

installations do require outages, they are much shorter than those required by traditional transmission projects. The following example shows how deploying GETs reduced the required outage.

> *"We are committed to providing reliable access to clean electricity to consumers at an efficient cost, and to playing our part in the energy transition. Technologies like this help us solve grid congestion and maximize the use of our existing grid, reducing, in some cases, the need for new infrastructure."*
> (Andrés Moreno Múnera, VP of Transmission and Distribution of Energy, EPM)

### CASE 7: FACTS AND RECONDUCTORING COMPARISON

Empresas Públicas de Medellin ("EPM") of Colombia has identified high congestion across three transmission lines that would limit the output of distributed hydro in future years in a metropolitan area where electricity demand is forecast to strongly grow.[29] EPM needed a grid upgrade option that could quickly resolve the congestion at lowest cost to consumers and with minimal impact on local communities. EPM evaluated several network options, including reconductoring the transmission corridor, which though they would increase the capacity of the transmission corridor, could be costly and would further take several years to complete, including the lengthy permitting processes. This option would also have negative impacts, including reduced grid capacity during its construction as the line would be out of service. EPM estimated two to two and a half years for reconductoring depending on outage coordination. EPM decided to use Smart Wires' (a vendor of modular FACTS devices) Static Synchronous Series Compensators ("SSSC"s) at two substations, providing the capability to push power off the overloaded line and pull power onto underutilized lines. Construction of the SSSC is estimated at nine months with outage time for commissioning of less than a week. EPM recognizes the benefit of scaling up the deployments or relocate the SSSCs to an alternate location as system needs change over time.

The following three examples illustrate how GETs can help mitigate outages caused by traditional transmission projects.

### CASE 8: FACTS FOR OUTAGE REMEDY

In 2015, Smart Wires analyzed the potential benefits of modular FACTS devices to support construction of new transmission lines. The utility needed to upgrade two 60 kV lines to two

[29] See: https://www.electricnet.com/doc/empresas-publicas-de-medellin-epm-announces-successful-effort-leveraging-modular-facts-0001

115 kV lines. Given the length and location of the lines (70 miles over a difficult terrain) and the need to replace the towers (from wood poles to steel towers), the estimated construction period was 3.5 years. Removing the two 60 kV lines required redispatch of generation, particularly in the summer season, to avoid overloading other nearby lines. The study identified that the redispatch could be avoided by installing modular FACTS devices that could reroute the flow from these otherwise overloaded lines. The annual costs of the modular FACTS devices were estimated to be between $1.5 million and $4 million, and the savings induced by avoiding redispatch were estimated to be over $20.5 million a year, therefore suggesting a savings of over $70 million (net-savings of $61.5 million to $69.7 million) over the construction duration period of 3.5 years (depending on when the construction starts). The $1.5 to $4.0 million investment is significantly smaller than (between 2% to 6% of) the avoided $70 million of congestion costs.

### CASE 9: TOPOLOGY CONTROL FOR OUTAGE REMEDY

In 2021, NewGrid studied several topology optimization options to alleviate the impact of transmission outages, and the system operator (MISO) implemented them. One was for the outage of Helena to Scott Co 345kV line (located near Minneapolis) to rebuild the line. This rebuild required extended outages from February 2021 through October 2021. As a result, the Chub Lake 345/115 kV transformer (for the loss of the Chub Lake to Hampton 345 kV line) constraint faced severe congestion. For the first three months (between February and April 2021) of the Helena to Scott Co 345kV line outage, the Chub Lake 345/115 kV transformer constraint was binding for more than 260 time intervals (12% of all hours), adding up to over $13 million in congestion costs. After MISO implemented a reconfiguration solution identified by NewGrid at the beginning of May, the constraint did not bind at all. The reconfiguration successfully and reliably increased throughput by up to 56% in the area. Conservatively assuming a similar amount of congestion (typically congestion would increase during the summer with higher loads), the reconfiguration is estimated to have saved about $40 million in regional market costs during the nine months-period.

While not directly associated with transmission outages for line upgrades, NewGrid also identified a reconfiguration solution to remedy severe congestion observed on the Raun to Tekanah 161 kV line (for the loss of Beaver Creek to Grimes 345 kV line) when the Ft. Calhoun to Raun 345 kV line faced a month-long forced outage from February 12, 2022 through March 12, 2022. NewGrid’s proposed reconfigurations (one reconfiguration of a substation and one opening of a transformer) were implemented and reduced the constraint binding down to 19 hours, from an estimated 114 hours, a mitigation rate of over 80%.[30]

The examples above illustrate how GETs can mitigate the impact of outages specifically during construction. Similar benefits are expected for other outages as well, even after the new transmission project is put into service, as discussed in *Section II. C. After Construction*. It is generally assumed that more than half of congestion observed today are from transmission outages. As a reference, SPP's 2016 Regional Cost Allocation Review ("RCAR") report assumes there are about 7,000 transmission outages per year in SPP.[31]

## C. After Construction

GETs can increase the value of the transmission projects ***after*** they are put in service in several ways. First, they can increase the utilization of both the new line(s) and the existing system, which increases the Benefit to Cost ratio of any given transmission project. This could allow for more transmission projects to pass the selection threshold (such as the Benefit to Cost ratio), and potentially enlarge the pool of potential transmission projects to be built. The complementary character of GETs is not limited to traditional transmission, but also with other GETs, which could further increase the benefits for transmission. This could allow for more transmission projects to pass the selection threshold (such as the Benefit to Cost ratio), and potentially increase the count of transmission projects to be built. Second, if energizing the new line results in unintended congestion, such as those on the underlying lower voltage lines, GETs could be quickly deployed to address it. This section discusses examples of each of these types here.

### CASE 6 (REVISITED): GETS FOR INTEGRATING MORE RENEWABLES IN SPP

While very few new high-voltage lines have been built in recent years, SPP has built a network of 345kV lines. The aforementioned "Unlocking the Queue" study, which modeled SPP, shows that GETs could enable 2,600 MW more of renewables. The study accounts for the projected 2025 system conditions, including transmission projects scheduled to be in service by then. The results showed that the value of these transmission projects increased as GETs enabled more renewables and lowered production costs. A post-study analysis of the study material

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30 The substation reconfiguration was implemented for a single day on February 15th, and the transformer opening was implemented on February 16th for the duration of the outage. Post-analysis indicates that if both reconfiguration suggestions were implemented, the constraint would not have bound.

31 RCAR report is available at: https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf

found the average utilization of the 345 kV lines in Kansas and Oklahoma (including the newly added lines) with GETs (DLR, Topology Control, and FACTS together) to be 16% higher than the case without GETs. This observation illustrates how GETs can increase the value of newly added transmission projects.[32] Combining GETs may allow for more new transmission projects to pass the Benefit to Cost ratio threshold, leading to more validation and realization of transmission projects.[33]

### CASE 10: FACTS AND DLR

In 2023, Smart Wires studied the combined capabilities of its FACTs device (digital power flow control technology) and DLR to increase grid capacity for 110 kV and 220 kV lines in Latin America for a set of scenarios. The study area projected high levels of renewable curtailment occurring in the study year (2024) and had high probability of new wind and solar generation seeking to interconnect into the area. Without any GETs, the available capacity on surrounding circuits would be 350 MW—which is significantly lower than the nominal system capacity. Congestion on three 220 kV circuits limited the output of existing and new generation resources in the area. Applying DLR alone increased transfer capability on this path by 100 MW. Adding flow controlling FACTs devices in two locations further increased the transfer capability by another 150 MW, resulting in a combined increase of 250 MW. When the control of the two GETs was harmonized (through software), over 300 MW of capacity was unlocked, increasing the total flow limit from 350 MW to 650 MW. This example shows how the combination of multiple types of GETs can complement each other and further increase the benefits.

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32 While the increased utilization was observed everywhere, the level did vary by project portfolio. The increase for the Balanced Portfolio (five 345 kV projects) was at 22% while it was 15% for the newly added 345 kV lines. This is likely because the renewable resources assumed in the study were those with Interconnection Agreements already signed today, indicating developers planned around the existing grid, rather than the future grid with additional upgrades. Yet, it does show positive benefits, even for the newer lines.

33 This example illustrates how GETs could increase the Benefit to Cost ratio of existing transmission assets. While a direct comparison to the original Benefit to Cost ratio is not possible, a 16% utilization increase, which is driven by more renewables, would likely increase the Benefit portion of the Benefit to Cost ratio by a similar amount, if not more. This indicates that a project that originally showed a Benefit to Cost ratio of 1.0 will now show 1.16, while a project that originally showed 1.25 will now show 1.45. A project that originally showed a Benefit to Cost ratio of 0.87 may now exceed 1.0, which is the decision threshold in some jurisdictions. The higher benefits brought by GETs would increase the number of traditional transmission projects to be permitted for construction within each jurisdiction.

### CASE 11: DLR AND OFFSHORE WIND CURTAILMENT

In 2022, LineVision installed its DLR platform for National Grid U.K. on a 275 kV circuit connecting Penwortham and Kirkby in Cumbria (north of England). This line has been experiencing congestion and curtailment as a result of surplus offshore wind generation. The project is estimated to provide an increase in capacity averaging more than 45%, which will allow 500 MW more renewable power to be carried. National Grid U.K. estimates the project will save £1.4 million (roughly $1.75 million) in network operating costs.

Other examples from *Section II. A. Before Construction* (see CASE 1: TOPOLOGY CONTROL FOR SPP CONSTRAINTS, CASE 2: TOPOLOGY CONTROL FOR MISO CONSTRAINTS, CASE 3: TOPOLOGY CONTROL FOR ALLIANT ENERGY, CASE 4: DLR FOR PPL 230 KV LINES, CASE 5: DLR FOR UPSTATE NEW YORK), and *Section II. B. During Construction* (see CASE 7: FACTS AND RECONDUCTORING COMPARISON, CASE 8: FACTS FOR OUTAGE REMEDY and CASE 9: TOPOLOGY CONTROL FOR OUTAGE REMEDY) illustrate similar applications of GETs mitigating congestion without waiting for more transmission builds to remedy the situation.

GETs can be utilized in ways beyond simply mitigating congestion. One example is using the Topology Control software to estimate the impact of outages.

### CASE 12: TOPOLOGY CONTROL FOR OUTAGE SCHEDULING

NewGrid’s Topology Control software could be used in ways other than identifying reconfiguration options for mitigating congestion. The software technology, designed to analyze changes in topology, can be used to analyze the impact of adding or removing a line or a group of lines. This ability provides unique applications of the software, such as evaluating the impact of transmission outages (for outage planning), identifying critical elements of the system (for general protection, to minimize load shedding caused by the loss of any elements, or to develop storm response and/or restoration orders), and evaluating the benefits of new lines (effectively “reconfiguring” the topology by adding a new line).

# III. GETs as Part of the Solution

As the previous section discussed through examples, GETs are complementary to traditional transmission projects and help enhance their value. The complementary nature of GETs is ideal to support the unprecedented transmission buildout (as discussed in *Section I. Introduction*), where the industry is seeking to *more than triple* the amount of transmission that is being added to the system annually over the next decade or two.

> *"Optimizing our existing transmission grid infrastructure to utilize its full capacity will prevent unnecessary costs and investment, leading to lower prices for consumers and faster deployment of new clean energy resources."*
> (Lisa Jacobson, President, Business Council for Sustainable Energy)

## A. GETs for Future Planning

Figure 1 shows historical and projected estimates of the annual transmission investments for the U.S. The figure shows annual transmission investments to be around $25 billion in recent years.[34] If we assume investments need to triple, that would imply $75 billion of investments per year for the foreseeable future. This pace and magnitude of transmission buildout can lead to two types of challenges. The first is a question of logistics and supply chain—will there be enough resources (e.g., equipment and labor) to pursue it? Second is the cost—who would bear the cost of these upgrades that will continue every year for two decades (or more)? Investments of $75 billion per year would raise the average electricity rates by almost $3/MWh every year.[35,36] The increase could be even worse, if costs go up, or if the credit ratings of the utilities drop because of the

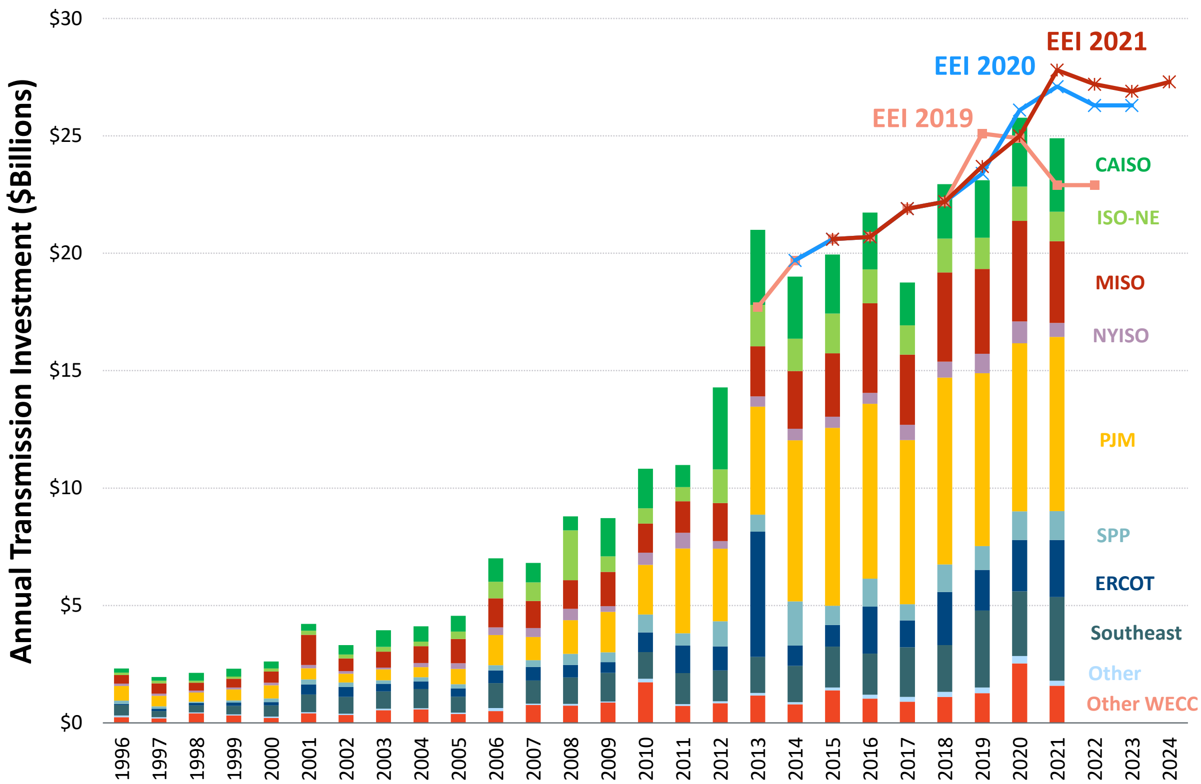
[34] Historical transmission investment data is based on FERC Form 1 Plant in Service Addition data for each RTO. EEI projections are based on investment figures obtained from the EEI Transmission Capital Budget & Forecast Survey, supplemented with data from company 10-K reports and other investor presentations. See: Hitachi Powergrids, Velocity Suite: https://www.eei.org/resourcesandmedia/Documents/Historical%20and%20Projected%20Transmission%20Investment.pdf

[35] The Energy Information Administration ("EIA") data shows U.S.-wide generation from utility-scale resources in 2019 to be approximately 4,100 TWh. $75 billion in investment, assuming a 15% carrying charge, would lead to $75 billion * 15% / 4,100 TWh = $2.74/MWh increase in rates every year.

[36] DOE's draft National Transmission Needs report observed that regional entities spent, on average, around $1.88 per MWh of annual load on new transmission in the past decade (with regional variations between $0.19 and $5.29 per MWh). Using the same metrics would calculate $6.25 per MWh for the $75 million investment.

large amount of debt.[37] Regulators will have to make decisions regarding rate increases, and steps towards optimizing the transmission system should be welcome.

FIGURE 1: HISTORICAL AND PROJECTED ANNUAL TRANSMISSION INVESTMENT IN THE UNITED STATES




Source: FERC Form 1 Data, EEI "Historical and Projected Transmission Investment" most recent accessed here: https://www.eei.org/resourcesandmedia/Documents/Historical%20and%20Projected%20Transmission%20Investment.pdf

Including GETs can help expand transmission capacity in shorter timeframes and at lower costs.

First, GETs will lower the overall amount of transmission needed, as combining transmission projects with GETs could significantly increase the amount of renewable integration. CASE 6: GETS FOR INTEGRATING MORE RENEWABLES IN SPP illustrates how adding GETs doubled the amount of renewables integrated, thereby, suggesting transmission needs could be reduced

[37] The Los Angeles Department of Water and Power estimated that a change in credit ratings by two notches could impact retail rates by roughly 20%. This impact is in addition to the rate increase associated with the new investments. See: Los Angeles Department of Water & Power Customers First, *Financial Considerations for LA100 Investments*, June 13, 2019 at https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=OPLADWPCCB681897&RevisionSelectionMethod=LatestReleased

by half if GETs are co-planned with traditional transmission projects. CASE 5: DLR FOR UPSTATE NEW YORK shows co-planning GETs with traditional transmission projects is already happening.

Utilizing GETs will contribute to a lower overall cost of the transmission buildout thanks to their significantly lower cost compared to traditional transmission.[38] CASE 6: GETS FOR INTEGRATING MORE RENEWABLES IN SPP suggests GETs could reduce investment cost by more than 45% to achieve similar renewable integration.[39]

It is perhaps note-worthy that GETs, once deployed widely, will likely pay for themselves through active congestion management. The savings from actively reducing congestion can vary greatly by the system and location. Congestion can be from multiple causes, including those triggered by outages during construction/interconnecting of a new lines. The prospect of a historic buildout of new lines (including upgrades) over the next decade or two implies a significant increase in outages and associated congestion.[40]

As the various examples from *Section II. Complementary Benefits of GETs at Different Stages of Transmission Expansion* illustrate, GETs can help mitigate, if not eliminate, congestion in many hours. CASE 8: FACTS FOR OUTAGE REMEDY shows FACTS completely eliminating congestion caused by transmission outages. CASE 9: TOPOLOGY CONTROL FOR OUTAGE REMEDY discusses two examples of Topology Control mitigating congestion caused by transmission outages—one example eliminated congestion completely while the other example mitigated it by over 80%. A recent study from MIT that analyzed the Electric Reliability Council of Texas ("ERCOT") suggests DLR can reduce congestion by 77%.[41] CASE 3: TOPOLOGY CONTROL FOR ALLIANT ENERGY shows Topology Control mitigated 40% of the congestion. These examples are

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38 For example, Topology Control solutions are software solutions and the incremental cost of software is considerably smaller than installing hardware. For DLR and FACTs associated solutions that involve hardware, examples (CASE 4: DLR FOR PPL 230 KV LINES, CASE 6: GETS FOR INTEGRATING MORE RENEWABLES IN SPP, and CASE 7: FACTS FOR OUTAGE REMEDY) illustrate the comparatively lower costs, oftentimes around 5% or less of the congestion cost that is being tackled. In many cases the cost of GETs can be smaller than the range of estimates for traditional transmission solutions.

39 Future transmission projects added up to $1 billion (slightly above) and GETs costs were at $90 million. The case without GETs integrated less than 2,600 MW of renewables while the case with GETs integrated more than 5,200 MW. Assuming a linear correlation another $1 billion is needed to integrate 5,200 MW of renewables without GETs. This indicates integrating 5,200 MW of renewables can be done by adding $2 billion of traditional transmission projects, or $1.09 billion ($1 billion of traditional transmission projects and $0.09 billion of GETs)—the cost difference is more than 45%.

40 In general, roughly half of the annual congestion is thought to be caused by planned transmission outages.

41 "Impacts of Dynamic Line Ratings on the ERCOT Transmission System" available at: https://arxiv.org/pdf/2207.11309.pdf

for a single technology, and as CASE 10: FACTS AND DLR shows, combining GETs could perhaps mitigate congestion even further. [42]

A recent study released by Grid Strategies titled "Transmission Congestion Costs in the U.S. RTOs" estimates the US-wide congestion costs for 2021 to be $13.4 billion.[43] This value is quite higher than previous years with annual congestion estimated to be in the $6 to $9 billion range.[44] The report, while recognizing the impact of Winter Storm Uri, discusses how congestion rose in the northeast regions by 72% in 2021 from 2020, driven by two factors: load rebounding from COVID-19, and transmission development not keeping up with renewable energy growth.

Assuming 40% of this congestion could be avoided by GETs (from CASE 3: TOPOLOGY CONTROL FOR ALLIANT ENERGY where Topology Control can mitigate 40% of the congestion), the avoided congestion costs benefits would add to more than five billion dollars a year. In the many examples, the ability of GETs to mitigate congestion is much higher, especially if they are to be combined. CASE 6: GETS FOR INTEGRATING MORE RENEWABLES IN SPP calculates the cost to deploy GETs nation-wide to be about $2.7 billion, which indicates a half-year payback period.

Apart from the monetary value indicated here, GETs mitigating congestion triggered by transmission outages will also facilitate new transmission buildouts because reducing the negative impact caused by the outages would improve the Benefit to Cost ratio.

The uncertainty surrounding future market conditions warrants considering GETs. GETs are modular and scalable, allowing owners to adjust the size of the installments over time, rather than having to commit upfront. The example below compares the benefits of this feature.

### CASE 13: FACTS AND PST COMPARISON

Smart Wires used real options analysis to compare two power flow control technologies—PST and modular Static Synchronous Series Compensators ("m-SSSC")—to find the optimal solution to resolve congestion on a 275 kV network. The difference between the two options is that m-SSSC devices are a flexible and scalable technology that can be easily expanded or relocated as system needs evolve over time. PSTs cannot be easily expanded, so the full solution needs to be built on day one. Accounting for unknowns and uncertainty associated

[42] The various examples reviewed in this white paper suggests GETs costs would be a small fraction of the annual congestion costs, often around 5% or less.

[43] The study is available at: https://gridprogress.files.wordpress.com/2023/04/transmission-congestion-costs-in-the-us-2021-update.pdf

[44] The 2021 value certainly does include the impact of Winter Storm Uri. The impact of this storm is estimated to be about a quarter of the annual congestion cost for MISO (~$750 million).

with future projection, the m-SSSC option was shown to deliver greater benefits (higher risk-adjusted Net Present Value) compared to the PST as it enabled the transmission owner to adapt the solution size depending on which scenario became the reality. This modularity and flexibility advantage would be ideal to be used in addressing the unintended congestion discussed above, especially because the magnitude of the unintended congestion may evolve over different seasons, or years.

Finally, the speed of deployment is another reason to consider GETs. GETs being modular and scalable can be installed much faster, as various examples, including CASE 4: DLR FOR PPL 230 KV LINES and CASE 7: FACTS AND RECONDUCTORING COMPARISON, show.

When combined with the lower costs and reversible deployments, this flexibility significantly lowers the risk of deploying GETs.[45] In addition, as CASE 4: DLR FOR PPL 230 KV LINES illustrates, the lead-time for installation is much shorter, and often does not require transmission outages. Finally, unlike many other capital-heavy assets, GETs are portable and can be removed once the need goes away. All these characteristics (portable, scalable, reversible, and low cost) point to GETs having very low risk in deploying. It would be ideal for utilities that are cash-strapped but still need to grow their transmission.

## B. GETs Under Severe Conditions

GETs can serve system operators well during extreme situations, also offering another benefit to the existing and future transmission system. GETs, especially DLR systems, will naturally increase the situational awareness of the weather and asset conditions by location at a much more granular level than is currently available. Second, some GETs provide means to control the flow for purposes exclusively to address extreme conditions, providing resiliency benefits. This section introduces four examples.

> *"The information we are collecting is helping us better balance strong resiliency while holding down costs."*
> (David Quier, VP of Transmission and Substation, PPL, on DLR)

45 The logistical/supply chain uncertainties and bottlenecks (including resource availability and scheduling delay) discussed briefly earlier, should be less severe if GETs are included as part of the solution.

### CASE 14: DLR AND EXTREME WEATHER

The value of DLR was demonstrated during the 2018 "bomb cyclone" when a 13-day cold snap between December 25, 2017 and January 8, 2018 constrained a large portion of the Northeast U.S. grid.[46] During this extreme event, which featured higher loads triggered by colder weather, ISO New England ("ISO-NE") issued an abnormal conditions alert to address both the weather and supply concerns. ISO-NE also increased their transmission line ratings (made possible by the cold conditions, which helped to improve thermal transfer capability), including the scheduling limits on the AC ties into New York (from 1,400 MW to 1,600 MW), which helped avoid large congestion costs.

### CASE 15: FLOW CONTROL DEVICES AND EXTREME WEATHER

Flow control devices also played a major role during the same 2018 cold snap. During this event, the New York Independent System Operator ("NYISO") saw a 50% to 100% increase in downstate prices (in particular, Zone J: New York City, in comparison to the Western region, Zone A: West), and initiated several NERC Transmission Loading Relief ("TLR") alerts. The two Ramapo PARs enabled NYISO to direct flows from PJM into eastern New York using its 500 kV path. NYISO has publicly acknowledged the reliability benefits that their PARs have previously provided: "The control capability provided by the two Ramapo PARs increases operational flexibility for NYISO. Power injections can be directed where needed for reliability."[47]

### CASE 16: TOPOLOGY CONTROL AND EXTREME WEATHER

The Brattle Group supported a utility in the upper Midwest to mitigate congestion and overloads under the extreme weather conditions during the Polar Vortex event of 2014. This weather event led to record-setting high loads in MISO due to extreme cold weather coupled with substantial number of unplanned generation outages triggered by the low temperatures. The very high loads and generation outages combined with extended 230 kV planned transmission outages led to severe post-contingency 115 kV transmission congestion and overloads affecting transmission utilities in the upper Midwest. The heavy congestion and overloads resulted in increasing the cost of electricity in the affected areas by over $15 million in the first 10 weeks of 2014. The Brattle Group performed a topology optimization analysis for one of the utilities impacted and identified reconfiguration solutions that relieved much of the congestion and overloads. These solutions were implemented by MISO after validation

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46 See ISO-NE, Cold Weather Operations: December 24, 2017–January 8, 2018, January 16, 2018

47 W. Yeomans, NYISO, Ramapo Phase Angle Regulator Cost Recovery, May 31, 2017, p. 8.

and discussion with the transmission owners in the area. The opportunity for improved performance with topology optimization under those severe conditions illustrate the resilience benefits of flow control technologies.

CASE 17: TOPOLOGY CONTROL TO AVOID ICING

In 2018, SPP studied the opportunity to apply flow control using topology control to heat lines and avoid icing during severe winter conditions.[48] The study was performed for the January 2017 Winter Storm Jupiter conditions, which led to multiple transmission outages caused by ice accumulation. The challenging conditions for restoration did not allow all outages to be addressed within the day. The study identified two reconfiguration solutions that could have prevented or significantly relieved the ice buildup on selected critical lines, while meeting reliability criteria. The estimated savings of hypothetical avoided outages of these critical lines were $10 to $17 million, in addition to the avoided costs of system restoration.[49]

While the occurrence (frequency, duration, magnitude) of these events and benefits of the remedies are difficult to project, these examples illustrate that one event would likely more than pay for the costs of the GETs.

# IV. Conclusion

The recent advancements in power electronics, communications, computer processing power, and optimization algorithms have led to the development of various new technology options designed to enhance the efficiency of the transmission grid. These new technologies, commonly known as GETs, include those that enable optimal and flexible application of the available transfer capacity, represented in this white paper by DLR, and those that focus on flexible and dynamic control of transmission systems, represented in this white paper by flow controlling FACTS devices and Topology Control software. When compared to major new transmission investments, GETs can be implemented much faster and often for a small fraction of the cost. As

48 This was a well-known practice many decades ago, see H.B. Smith, and W.D. Wilder, "Sleet-melting practices—Niagara Mohawk system," *Transactions of the American Institute of Electrical Engineers. Part III: Power Apparatus and Systems*, Vol. 71, Issue 3, Aug 1952, pp. 631–634.

49 See Ruiz P., *et al.*, "Transmission topology optimization: pilot study to support congestion management and ice buildup mitigation," SPP Technology Expo, Nov 2018.

indicated by the cases above, the benefits of GETs accrue ***before***, ***during,*** and ***after*** the construction of new transmission lines.

- Before construction, GETs can reduce congestion by 40% or more.
- During construction, outages can be avoided or ameliorated, with similar reductions in congestion costs of 40% or more.
- And after construction, utilization on new lines can increase by 16%, improving the Benefit to Cost ratio of the new lines.

These technologies are highly complementary to transmission expansion through new lines. They can magnify the cost effectiveness and capabilities provided by new transmission investments. They provide short-term solutions to temporary operational challenges, such as during transmission outages or the construction of new lines, and bridge gaps until permanent expansion solutions can be put in place. They also are realistic alternatives for long-term solutions, particularly where building transmission makes less economic sense. GETs enhance transmission investments, rather than eliminating them, acting more as a tool to augment, akin to a GPS or tire air pressure sensor making driving easier—not by themselves replacing the car.

The needs for these technologies will only increase as the pace of the energy transition accelerates and necessitates doubling or even tripling of grid capacity over the next ten to 20 years. The pace and magnitude of this challenge requires an unprecedented effort and it is unlikely to succeed if transmission owners and planners only focus on the traditional transmission development approach. It is prudent to consider GETs—a complementary technology to transmission—as part of the solution for expanding future transmission.

> *"….from a Belgium perspective what I can say 10 years ago for dynamic line rating I mean we're talking about this internally, the system engineers are just looking at us like crazy guys, what are you speaking about. This is a gadget you want to install on the transmission line? It's just crazy, we're really against it, totally against these, the usual. And now 10 years later they're just asking for more. They just complain when there is congestion, and there no passing the line, and the customers, there are many other technologies probably as good as this, it's just complying and saying you should install more."*
>
> (Victor LeMaire, Operational Planning, Elia, during the 2021 FERC technical conference "Workshop to Discuss Certain Performance-based Ratemaking Approaches.")

# Glossary

| | |
|---|---|
| AC | Alternating Current |
| DC | Direct Current |
| DLR | Dynamic Line Ratings |
| DOE | Department of Energy |
| EIA | Energy Information Administration |
| EPAct | Energy Policy Act of 2005 |
| EPM | Empresas Públicas de Medellin |
| ERCOT | Electric Reliability Council of Texas |
| EU | European Union |
| FACTS | Flexible Alternating Current Transmission Systems |
| FERC | Federal Energy Regulatory Commission |
| GETs | Grid-Enhancing Technologies |
| GPS | Global Positioning System |
| GW | Giga-Watt (1,000 mega-watts, 1,000,000 kilo watts, or 1,000,000,000 watts) |
| ISO-NE | ISO New England |
| ITP | Integrated Transmission Planning |
| kV | Kilo-Volt (1,000 volts) |
| LBNL | Lawrence Berkeley National Laboratory |
| LTRA | Long-Term Reliability Assessment |
| MISO | Midcontinent Independent System Operator |
| MIT | Massachusetts Institute of Technology |
| MW | Mega-Watt (1,000 kilo-watts, or 1,000,000 watts) |
| m-SSSC | Modular Static Synchronous Series Compensators |
| NARRUC | National Association of Regulatory Utility Commissioners |
| NERC | North American Electric Reliability Corporation |
| NOPR | Notice of Proposed Rulemaking |
| NYISO | New York Independent System Operator |
| PAR | Phase Angle Regulators |
| PST | Phase Shifting Transformers |
| RCAR | Regional Cost Allocation Review |
| SPP | Southwest Power Pool |
| SSSC | Static Synchronous Series Compensators |
| TADS | Transmission Availability Data System |
| TLR | Transmission Loading Relief |
| TW | Terra-Watt (1,000 giga-watts, 1,000,000 mega-watts) |