Incorporating GETs and HPCs into Transmission Planning Under FERC Order 1920

PREPARED BY

The Brattle Group

T. Bruce Tsuchida
Linquan Bai
S. Ziyi Tang

Grid Strategies

Jay Caspary

PREPARED FOR

The American Council on Renewable Energy (ACORE)

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Brattle

ACORE
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NOTICE

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Please direct any questions or comments to T. Bruce Tsuchida: Bruce.Tsuchida@brattle.com.

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Executive Summary

The energy landscape in the United States is currently undergoing an unprecedented transformation. Rapid technology developments and fast-emerging new loads – from data centers and cryptocurrency mining to electrified transportation and industrial processes – are reshaping electricity generation, consumption, and delivery. This transition requires a massive expansion of the electric transmission grid, with estimates suggesting that transmission capacity must double or triple in the coming decades.[1] In addition to these extraordinary transmission needs, the pace of expansion must accelerate to fulfill near-term grid demand.

Such seismic shifts will also require the nation's transmission providers to update their transmission planning processes. Transmission providers must not only plan for future needs but also factor in the uncertainties surrounding the industry – including those associated with costs and schedules of the transmission investments, and the possibility that new loads either do not materialize or may grow at an even more rapid pace than projected.

The Federal Energy Regulatory Commission's (FERC's, or Commission's) recent Order 1920 and its subsequent order on rehearing, Order 1920-A, mark a critical milestone in addressing these challenges by mandating scenario-based, long-term transmission planning. Among other mandates, Order 1920 requires transmission providers to (1) develop at least three plausible and diverse scenarios that identify both long-term transmission needs and potential solutions, (2) quantify the benefits of the potential solutions, and (3) establish an evaluation process for selecting among the potential solutions.

Order 1920 does not prescribe the details of scenario development, evaluation processes, or selection criteria for assessing future transmission solutions; instead, it leaves them to the respective transmission providers to submit to the Commission for approval. However, the Order does provide certain broad standards that these criteria must meet – primarily that the evaluation processes must aim to ensure the selection of more efficient or cost-effective facilities and that the benefits must be weighed against the costs.

Order 1920 does ask transmission providers to consider alternative transmission technologies (ATTs) as part of their potential solutions.[2] ATTs discussed in the Order include certain Grid-Enhancing Technologies (GETs) – namely, Dynamic Line Ratings (DLR), Advanced Power Flow Control (APFC), and Transmission Switching – as well as High-Performance Conductors (HPCs).

1 Several examples of studies are discussed in a Brattle/WATT Coalition report. See WATT Coalition, *Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts* (April 2023), https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf.

2 This report will refer to Orders 1920 and 1920-A (including as modified on rehearing) collectively as "Order 1920" unless the specific revisions made in Order 1920-A are being discussed. FERC issued Order 1920-B on April 11, 2025, in response to requests for rehearing of Order 1920-A and made no changes to the requirements of Orders 1920 and 1920-A relevant to the alternative transmission technology or state engagement provisions described in this paper.

ATTs are cost-effective, scalable, and faster-to-implement technology choices when compared to traditional wires-based solutions, such as building new lines on new paths, reconductoring existing lines using conventional conductors, or building parallel lines to increase transfer capability within an existing path. And, despite the several barriers that must be navigated to prevent underinvestment in ATT solutions, Order 1920 presents significant opportunities – particularly for states – to enhance the consideration of ATTs and promote their broader adoption.

In this report, we aim to highlight both the pitfalls and opportunities of ATTs. Specifically, we cover the benefits of ATTs (focusing on GETs and HPCs), how current planning processes may be inadequate for consideration of ATTs, and how Relevant State Entities (RSEs) – defined as any state entity that is responsible for electric utility regulation or siting electricity transmission, or another entity designated by state law – can encourage transmission providers to integrate ATTs into their transmission planning and selection.

BENEFITS OF ATTS (SEE SECTION II)

ATTs have three distinct key characteristics when compared to traditional wires-based solutions. These are:

- ✓ Lower cost and faster installation
- ✓ Complementarity to existing equipment
- ✓ Portability and reversibility (for GETs only)

Integrating ATTs (which may include other technology options as determined by transmission providers since Order 1920 is not restrictive to the technologies that are specified) into long-term transmission planning provides numerous benefits, including, at a minimum, the "*Seven Benefits*" Order 1920 requires transmission providers to consider when evaluating and selecting transmission facilities:[3,4]

- ✓ ***Benefit 1***: Avoided or deferred reliability transmission facilities and aging infrastructure replacement
- ✓ ***Benefit 2***: Reduced loss of load probability or reduced capital costs to meet planning reserve margin
- ✓ ***Benefit 3***: Production cost savings
- ✓ ***Benefit 4***: Reduced transmission energy losses
- ✓ ***Benefit 5***: Reduced congestion due to transmission outages
- ✓ ***Benefit 6***: Mitigation of extreme weather events and unexpected system conditions
- ✓ ***Benefit 7***: Capacity cost benefits from reduced peak energy losses

A review of 25 case studies of ATTs (limited to those specifically listed in Order 1920) shows that each of the *Seven Benefits* can be provided by ATTs. Figure ES-1 summarizes the 25 case studies, including which ATTs were used and the *Benefit(s)* – numbered 1 through 7, corresponding to the above list – that were observed. Each implementation may have shown other benefits either not captured in the Order 1920 list or not quantified in the report.

The table shows that ATTs are capable of providing all of the *Seven Benefits*. The vintages of some of the case studies show that ATTs are proven and mature technologies, making them viable solutions for improving and expanding the transmission system efficiently and reliably.

CURRENT PLANNING PROCESSES AND ATTS (SEE SECTION III)

The current deterministic framework used for transmission planning – which is built on static future snapshots – may not be adequate to evaluate and compare the *Seven Benefits* of Order 1920. A more holistic approach that considers different timeframes, alternative system conditions, and an evolved evaluation methodology and selection criteria is needed.

For example, some of the *Seven Benefits* (including *Benefits 1* and *7*, and, to some degree, *Benefit 2*) can reduce investment needs and may be captured in current planning processes that compare investment cost options. However, others – like *Benefits 3, 4*, and

3 This report will use italicized font (*Benefits*) to refer to the *Seven Benefits* outlined in Order 1920, while using regular font (benefits) for generic terms.

4 The combination of these three characteristics improves the utilization of the existing assets – including increasing efficiency – and increases situational awareness (for many GETs in particular), which contribute to better operations and higher reliability.

FIGURE ES-1: ATT CASE STUDIES AND *SEVEN BENEFITS*

Case Study #	Technology	Benefits						
		1	2	3	4	5	6	7
1: DNV-GL PJM Study	APFC	x		x				
2: DOE Lift-off Report	GETs	x						
3: SCE HPC and Transmission Towers	HPC	x						
4: NY DLR	DLR	x						
5: DOE GETs Report	DLR, APFC	x						
6: 2018 "Bomb Cyclone" and DLR	DLR (AAR)		x				x	
7: SPP Winter Storm Jupiter	TS		x				x	
8: SPP Winter Storm Elliot	TS		x				x	
9: HPC Design and History	HPC						x	
10: Brattle SPP GETs Study	DLR, TS, APFC			x	x			
11: RMI PJM GETs Study	DLR, TS, APFC			x				
12: Transmission Switching Studies	TS			x			x	x
13: GRE DLR	DLR			x				
14: ELIA DLR	DLR			x				
15: Hydro Quebec Conductors Comparison	HPC				x			
16: APFC 2015	APFC					x		
17: EPM and AFC	APFC					x		
18: Transmission Switching Study	TS					x		
19: PJM Winter Storm Elliot	DLR						x	
20: Nevada Energy HPC	HPC						x	
21: Oklahoma Gas and Electric HPC	HPC						x	
22: California Wildfire and HPC	HPC						x	
23: Canada Icing and HPC	HPC						x	
24: Southeastern US and HPC	HPC						x	
25: New York Phase Angle Regulators	APFC, TS							x

5, which could immediately lower customers' bills – are more operational in nature and require a more granular analysis (e.g., hourly) over the operational timeframe rather than the longer planning horizon. *Benefits 5* and *6* are temporal events that further require the evaluation of alternative system conditions for shorter timeframes.[5]

The evaluation methods and solution selection processes, which often compares potential solutions, also need to be carefully implemented to ensure the broad suite of benefits ATTs provide is fully considered. An evaluation methodology that looks across all *Seven Benefits* (rather than on an individual benefit-by-benefit basis) is required since – even if the scoring for an individual *Benefit* is mediocre for a given solution – the sum of multiple *Benefits* may outweigh other solutions that score high in just one *Benefit*.

Furthermore, certain ATTs, including GETs, may not be directly comparable to other potential solutions. For example, comparing a new line to a GETs-alone solution (such as DLR) over a 20-year period misses the point. In this example, the more appropriate comparison would be a new line without GETs to a new line supported by GETs.

These observations highlight the complexity of evaluating the *Seven Benefits* across various technology options, including ATTs. The challenge of developing a comprehensive evaluation methodology and criteria could become a hurdle for implementing ATTs and other non-traditional solutions into the planning process. In addition, a review of the current (i.e., pre-Order 1920) planning processes identifies four barriers to implementing ATTs:

5 HPCs can provide *Benefit 6* (Mitigation of extreme weather events and unexpected system conditions) through their robust design and structure. This may be an exception (i.e., not an operational benefit), although one will still have to model temporal system conditions.

1. Insufficient recognition of the ATTs themselves;
2. Misaligned incentives;
3. The use of traditional planning approaches that tend to be static and deterministic; and
4. The perceived lack of standardized data, tools, and analysis methodologies, along with human resources capable of carrying out advanced analyses.

CONSIDERATIONS FOR RELEVANT STATE ENTITIES (SEE SECTION IV)

Order 1920-A assures that RSEs can demand greater transparency and flexibility in the long-term regional transmission planning processes. The amendment allows RSEs to engage in the evaluation process by offering inputs on the evaluation methodology and selection criteria, contributing to scenario development, or suggesting additional scenarios and/or benefits for the transmission provider to consider during the solution selection process.

Orders 1920 and 1920-A also provide RSEs and transmission customers the option to voluntarily fund part or all of the cost of a proposed transmission solution. This option could improve the selection process for ATTs if the transmission provider's evaluation process includes relevant and appropriate measures, such as a benefit-to-cost ratio criterion.

For RSEs to fully take advantage of these levers provided by Order 1920-A, they must recognize the aforementioned implementation barriers together with the benefits ATTs can provide. Benefits are not limited to the *Seven Benefits* outlined in Order 1920; they can extend to benefits associated with certainty, time, and optionality. For example, GETS can offer immediate remedies to issues like congestion while providers plan for more permanent solutions (e.g., new wires), without concerns about the new GETs assets becoming stranded. Here, the GETs investments – which often have payback periods of months rather than years – not only solve the existing issue but can also offer transmission providers additional time needed to best plan for the future. Although the value of such time-associated benefits (i.e., avoided risks) is more challenging to quantify in monetary terms and will vary by transmission provider and needs, they should be considered in planning activities moving forward.

Moreover, RSEs should recognize that transmission providers may not prioritize cost-avoidance as covered by Order 1920's *Seven Benefits* because transmission costs are typically passed through to customers – meaning transmission providers (both operators and owners) may have limited incentives to pursue transmission or technology solutions that produce cost-savings for customers.[6] Thus, states may need to directly engage with transmission providers to ensure that cost-saving solutions are not overlooked during the transmission planning and solution selection process. States should explore policies and incentives that would further encourage transmission providers to pursue lower-cost solutions.

By introducing and discussing these topics with providers and other stakeholders, RSEs could significantly impact transmission planning, especially the selection process. States can encourage transmission providers to be technology-neutral and cost-conscious in a collaborative way while remaining objective and focused on state initiatives and consumer protection.

6 FERC Order 888 defines "transmission provider" as a "public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff." Investment costs are typically passed through by the owners to the customers. Operators can also pass through costs. For example, end users pay for congestion if the operator does not utilize Transmission Switching to relieve congestion, even when it is appropriate to do so.

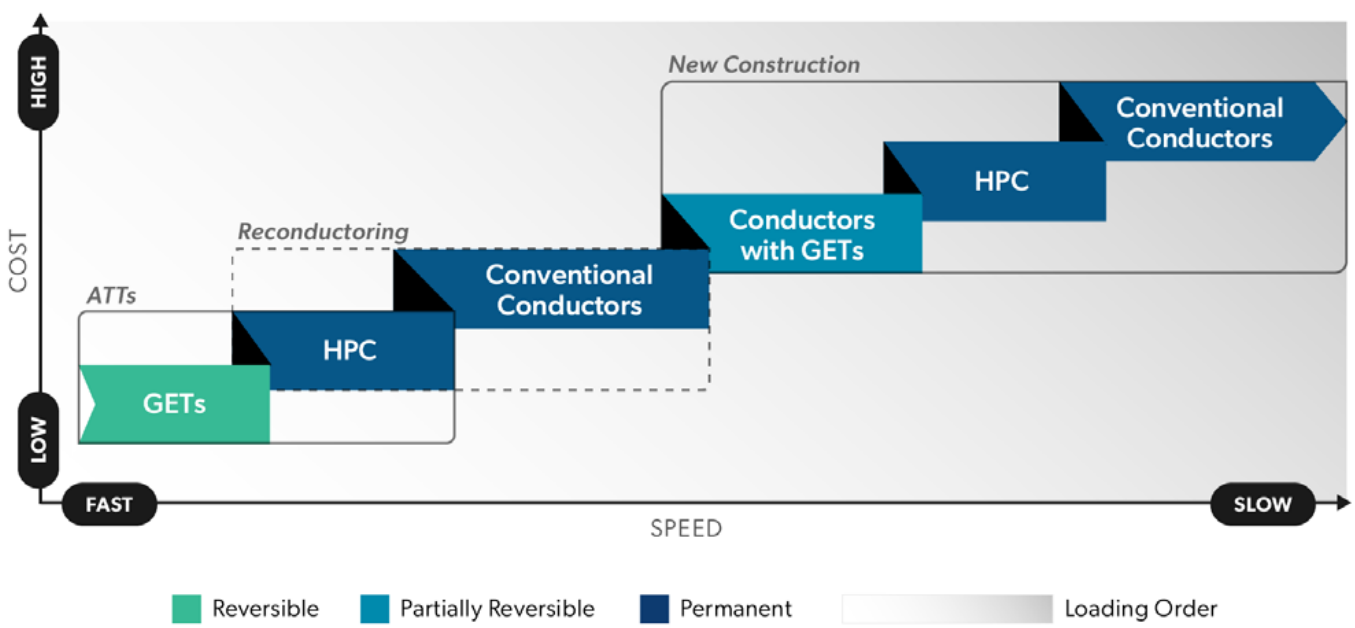
To encourage transmission providers to consider ATTs in their planning, RSEs could request transmission providers consider a reasonable number of additional scenarios – beyond the minimum three mandated in Order 1920 – in their planning that include ATTs.[7] Additionally, since Order 1920 also requires the transmission providers to consult with and seek support from the RSEs when developing the evaluation process and selection criteria,[8] RSEs could advocate for the inclusion or omission of certain selection criteria; for example, RSEs could request removing any criteria that would bias the selection process against ATTs – such as qualitative criteria that are subjective and difficult to evaluate, or rankings solely based on maximum net benefits – without any consideration for benefit-to-cost ratios.

With these options available, RSEs could effectively develop a preferred loading order for transmission selection that aligns with state priorities. Examples of such loading orders may prioritize lower-regrets solutions or higher benefit-to-cost ratios. Lower-regrets options may include solutions that provide future optionality (e.g., replacing an existing substation with one that – compared to the original design – uses more flexible arrangements, such as a ring bus or double bus design, to provide more expansion options). "Right-sizing" is often a lower-regrets option.[9] For finding such solutions, the selection process may focus on mitigating costs and the associated risks of not proactively right-sizing (by looking at the longer-term rather than immediate upfront costs).

A higher benefit-to-cost ratio can be achieved by first optimizing the existing grid, such as by using GETs; then upsizing existing lines, such as through HPCs; and finally adding new lines using conventional technologies or HPCs when ATTs alone do not make sense as standalone solutions, as illustrated in Figure ES-2.

Part of this exercise may require establishing "rules of thumb" to help evaluate potential solutions at a high level (more for screening purposes), such as prioritizing GETs for transfer increase needs of 25% or less and prioritizing HPCs for

FIGURE ES-2: ILLUSTRATIVE LOADING ORDER



7 Scenarios that compare a solution with and without ATTs (with all else being equal) could help highlight the benefits of including ATTs.

8 Order 1920 does require transmission providers to provide a six-month state engagement process prior to submitting compliance filings. However, some of the analyses and stakeholder processes could take longer than six months, indicating RSEs would want to be engaged even earlier to help shape the discussion.

9 Lower-regrets is slightly different from least-regrets as defined by FERC. Least-regrets looks at the common upgrades found in most, if not all scenarios, regardless of the future/inputs and always beneficial. For example, assume five scenarios were studied and each scenario showed building a new transmission line for the same path. Some scenarios suggested a 138 kV line while other scenarios suggested a 169 kV line to be built. The least-regrets may choose to build the 138 kV line (i.e., build the smallest common denominator) while the low-regrets may choose to build the 169 kV, considering that the scenarios indicate a reasonable chance of requiring the 169 kV line, rather than the 138 kV. A similar observation could be made by looking at lower costs over the longer run, rather than the immediate upfront costs

transfer increase needs of 50% or more or when "right-sizing" opportunities are observed. A pre-screening cost threshold (e.g., normalized in $/MW investment costs) could also be developed for this purpose.[10] It should be noted that any rules of thumb or heuristics start broad and are then refined and updated later as transmission planners gain more experience in evaluating various technologies, including ATTs.

As we explore in this report, integrating ATTs into transmission planning and selection is not just an opportunity, but a necessity for achieving cost-effective, timely, and sustainable grid development over the next several decades. FERC's framework provides a strong foundation, but proactive efforts from all stakeholders will be essential to overcome barriers, realize the full potential of these technologies, and accelerate the industry transition.

The success of Orders 1920 and 1920-A will depend on the willingness of transmission providers to embrace these innovative solutions, modernize their frameworks, and deliver a grid development plan that is reliable, efficient, and ready for the future. Active and collaborative engagement from RSEs, combined with their guidance to ensure accountability for transmission providers, will be essential for achieving success.

10 For example, if the rule of thumb savings is $50/kW then one could use that value to screen the various solutions and weed out those that cost more than the benefit (in this example, say more than $70/kW with some cushion).

I. Introduction

A. Background

The US energy industry is going through a massive transition, one that is partially driven by new large loads, including data centers and the onshoring and expansion of manufacturing and industrial processes. Decarbonization initiatives – such as incentives for electric vehicle (EV) use or heating and processing applications for buildings and industry – are also significantly increasing electrified load. Major factors indicating the need for and benefits of expanded transmission include the facts that (a) the preferred siting locations for many of the new large-scale resources associated with these loads could often be in remote areas far from consumption, and (b) extreme weather events have increasingly created periodic spikes in demand and reliability risks.[11]

In addition, as Figure 1 shows, the industry has been recognizing the need to replace aging transmission facilities that are nearing the end of their useful lives.[12,13] Considering these factors, various studies have indicated the urgent and massive need for transmission, generally estimating the US will need to double or even triple its electric transmission capacity within the next few decades.[14]

In July 2021, FERC issued its Advanced Notice of Proposed Rulemaking (ANOPR) titled "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" (Docket No. RM 21-17-000), followed in April 2022 by the issuance of a Notice of Proposed Rulemaking (NOPR) that outlined specific reforms. Comments provided to the ANOPR and NOPR were reflected in the subsequent Order 1920, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation," issued in May 2024.[15]

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11 The intermittent nature of these weather-dependent resources also contributes to the need for more transmission, which helps to capture the diversity of their availability across time and geography, along with the diversity of demand. See Michael Goggin and Zach Zimmerman, Grid Strategies, LLC for the American Council on Renewable Energy (ACORE), *Billions in Benefits: A Path for Expanding Transmission Between MISO and PJM* (November 2023), https://acore.org/resources/billions-in-benefits-a-path-for-expanding-transmission-between-miso-and-pjm/.

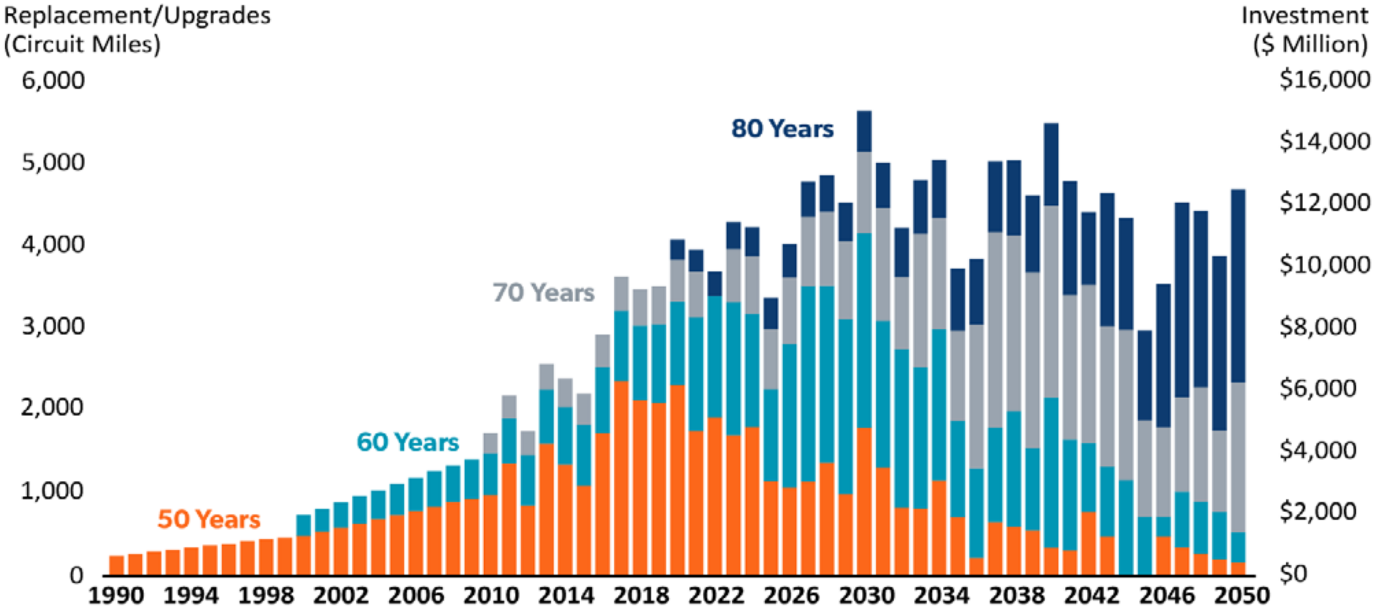
12 For example, a Princeton University study estimates the aging US transmission grid replacement costs of over $2.4 trillion by 2050. See Princeton University, *Net-Zero America: Interim Report* (December 15, 2020), https://netzeroamerica.princeton.edu/img/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf.

13 Figure 1 is based on Brattle analysis. Facilities that need to be replaced after 50 to 80 years now likely account for $10 billion in annual transmission investment and are estimated to have reached up to 80% of total assets in some regions, such as PJM.

14 Studies include the National Renewable Energy Laboratory's *North American Renewable Integration Study* (https://www.nrel.gov/analysis/naris.html) and "Interconnections Seam Study" (https://cleanenergygrid.org/wp-content/uploads/2018/08/NREL-seams-transgridx-2018.pdf), the Massachusetts Institute of Technology's *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System* (https://www.cell.com/joule/fulltext/S2542-4351(20)30557-2?_returnURL=https://linkinghub.elsevier.com/retrieve/pii/S2542435120305572?showall%3Dtrue, and the US Department of Energy's *National Transmission Needs Study* (https://www.energy.gov/gdo/national-transmission-needs-study).

15 Order 2023 "Improvements to Generator Interconnection Procedures and Agreements" (Docket No. RM22-14-000) evolved from the same ANOPR and a separate NOPR that was issued in July 2023.

FIGURE 1: ESTIMATED US AGING-ASSET REFURBISHMENT NEED



Most recently, FERC issued Order 1920-A, affirming Order 1920 with modifications to address requests for rehearing and clarification. Order 1920-A sought to strengthen the role of the Regional State Entities (RSEs) – which are defined as any state entity responsible for electric utility regulation or siting electricity transmission, or another entity designated by state law – in the long-term regional transmission planning process.

FERC has recognized Grid-Enhancing Technologies (GETs) and Advanced Conductors (or High-Performance Conductors, HPCs) through the ANOPR, NOPR, and the latest Orders as potential solutions to be considered for transmission expansion (either through generation interconnection in Order 2023, or for long-term transmission planning in Order 1920). Specifically, Order 1920 outlines *Seven Benefits* that long-term transmission planning should consider when selecting facilities and asks transmission providers to apply them to all potential transmission solutions, including GETs and HPCs.

In the meantime, within the nearly four-year rule-making process, the need for and benefits of transmission expansion has grown. Transmission congestion remains a persistent source of additional costs and has worsened in recent years. As Figure 2 shows, the average annual congestion costs estimated for the last three years (2021–2023) more than doubled from that of the previous three years (2018–2020).[16] Furthermore, the industry is now facing an uptick in new large loads, including artificial intelligence (AI)-driven data center expansion, electrification of industrial and heating processes, electrified transportation, and cryptocurrency mining.

These load drivers, when combined, indicate a significantly larger load growth than what the industry observed over the past two decades and at a pace that is much faster than the industry's planning cycles, oftentimes requesting services within a year or two.[17] In fact, the five-year load growth forecast over the past two years has increased by almost a factor of five, from 23 GW to 128 GW, as Figure 3 shows.[18] These developments further stress the need for timely transmission (and generation) expansion and the importance of Order 1920 (along with Order 2023).

16 Grid Strategies, *2023 Transmission Congestion Report* (September 2024), https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies_2023-Transmission-Congestion-Report.pdf.

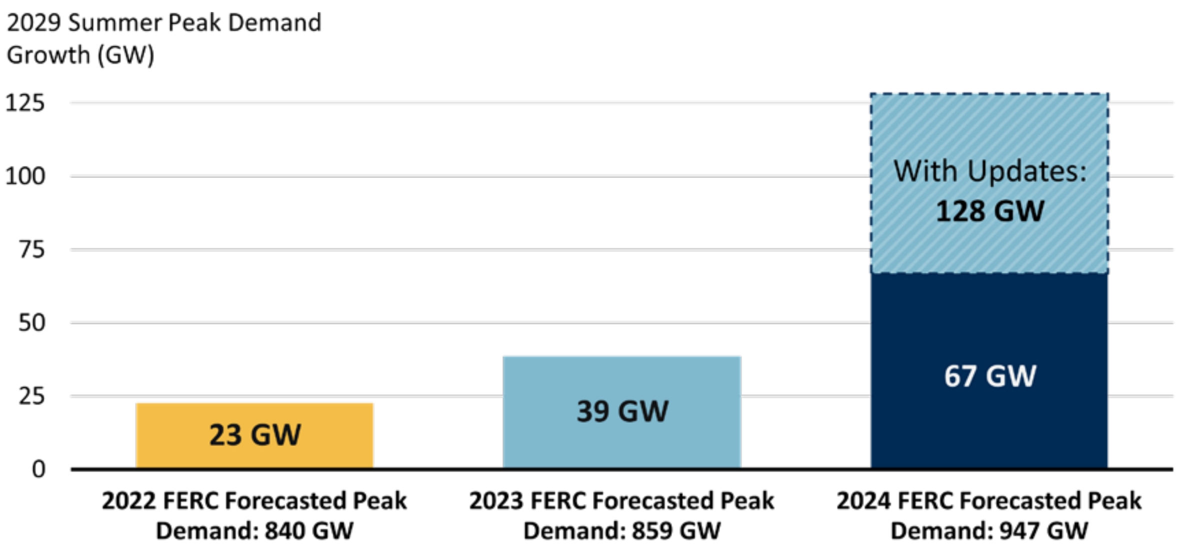
17 Basin Electric Power Cooperative, in its FERC rate filing for new large loads and cryptocurrency mining load (docket ER24-1610-000), indicated that cryptocurrency mining load within its service territory grew from approximately 5 MW in July 2022 to over 200 MW by May 2023.

18 Grid Strategies, *Strategic Industries Surging: Driving US Power Demand* (December 2024), https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf.

FIGURE 2: ESTIMATED TRANSMISSION CONGESTION COSTS ($ MILLION) BY YEAR

	2016	2017	2018	2019	2020	2021	2022	2023
ERCOT	497	976	1,260	1,260	1,400	2,100	2,800	2,400
ISO-NE	39	41	65	33	29	50	51	32
MISO	1,402	1,518	1,409	934	1,181	2,849	3,700	1,800
NYISO	529	481	596	433	297	551	1,000	311
PJM	1,024	698	1,310	583	529	995	2,500	1,068
SPP	280	500	450	457	442	1,200	2,000	1,400
CAISO	197	138	745	451	605	760	1,323	1,049
TOTAL	**3,968**	**4,352**	**5,835**	**4,151**	**4,483**	**8,505**	**13,374**	**8,060**

FIGURE 3: PROJECTED LOAD GROWTH



B. FERC Order 1920

FERC Order 1920 (together with its sister Order 2023) is a major milestone in modernizing transmission planning. The ANOPR and the NOPR preceding these Orders together received over 32,000 pages of comments and appendices – one of the largest records ever considered by FERC.[19] Building on the frameworks established by Orders 890 and 1000 while addressing remaining gaps in regional transmission planning, Order 1920 requires scenario-based, long-term planning to address challenges like integrating renewable energy, improving grid reliability, and ensuring fair cost-sharing for major transmission projects.

FERC Order 890, issued in 2007, was the first step toward making transmission planning more transparent and inclusive.[20] Order 890 required utilities to adopt open planning processes that allowed

19 Federal Energy Regulatory Commission, "Staff Presentation: Building for the Future Through Electric Regional Transmission Planning" (May 13, 2024), https://www.ferc.gov/news-events/news/staff-presentation-building-future-through-electric-regional-transmission-planning.

20 FERC Order 890, available at: https://www.ferc.gov/sites/default/files/2020-05/E-1fr890.pdf.

stakeholders to participate in identifying grid needs. This laid the foundation for a more collaborative approach to grid development. In 2011, FERC Order 1000 expanded these principles by requiring regional and interregional planning, incorporating public policy goals like renewable portfolio standards (RPS), and introducing competitive processes to encourage cost-effective solutions.[21] These efforts highlighted the need for a forward-looking grid planning process but left gaps in the planning needed to address rapid technological and policy changes.[22]

FERC Order 1920 builds on this legacy by mandating that transmission providers consider multiple future scenarios over a longer (20-year) time horizon, including the integration of new resources and growing load, among other policy goals.[23] The Order asks transmission providers to use these scenarios to identify transmission needs and establish a process for selecting transmission that quantifies benefits and identifies the solution that maximizes benefits, accounting for costs, while leaving the specifics of the selection process and criteria used for each region to determine. Such criteria may include least-regrets, minimum benefit-to-cost ratio, and highest net benefits, among others, and can further be a combination of them. Moreover, Order 1920 asks transmission providers to "right-size" transmission facilities, at a minimum, for assets that are rated at 200 kV and above and may be replaced over the next ten years.

To help guide the analysis and criteria required for the selection process, Order 1920 outlines the following *Seven Benefits* that transmission providers must consider, at a minimum, when evaluating transmission facilities:[24,25]

- ✓ ***Benefit 1***: Avoided or deferred reliability transmission facilities and aging infrastructure replacement
- ✓ ***Benefit 2***: Reduced loss of load probability or reduced capital costs to meet planning reserve margin
- ✓ ***Benefit 3***: Production cost savings
- ✓ ***Benefit 4***: Reduced transmission energy losses
- ✓ ***Benefit 5***: Reduced congestion due to transmission outages
- ✓ ***Benefit 6***: Mitigation of extreme weather events and unexpected system conditions
- ✓ ***Benefit 7***: Capacity cost benefits from reduced peak energy losses

Order 1920 specifically asks transmission providers to consider alternative transmission technologies (referred to in this report as ATTs and discussed further in the next section, Section I.C: Overview of GETs and HPCs) along with the traditional wires-based solutions[26] and share with stakeholders the evaluation performed in sufficient detail to communicate how the transmission provider reached its preferred solution(s). By incorporating such technologies into scenario-based planning, Order 1920 aims to ensure that transmission development can keep pace with the evolving needs of the industry while reducing costs and schedule delays.

In November 2024, recognizing the need for further refinements, FERC issued Order 1920-A, which strengthened the role of RSEs in the transmission planning process.[27] Order 1920-A specifically ensures that the perspectives of RSEs are incorporated into the transmission planning and cost allocation processes. Such provisions of the Order include requirements for transmission providers to consult with RSEs on the development of the

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21 FERC Order 1000, available at: https://www.ferc.gov/electric-transmission/order-no-1000-transmission-planning-and-cost-allocation.

22 Section III. Current Planning Processes and ATTs summarizes the current (i.e., pre-Order 1920) transmission planning process. Appendix B: Current Transmission Planning Processes illustrates this summary using the Southwest Power Pool as an example.

23 FERC Order 1920, available at: https://www.ferc.gov/media/e1-rm21-17-000. Order 1920 requires transmission providers to develop at least three "plausible and diverse" long-term (i.e., 20 years or longer) scenarios that reasonable capture probable future outcomes considering seven planning factors (also outlined in Order 1920), along with at least one sensitivity for such scenarios. Sensitivities can include extreme weather, significant forecast errors, fuel price volatility, cyber-attacks, and other uncertainties.

24 Order 1920-A removed the requirement for transmission providers to consider the *Seven Benefits* in the determination of the transmission needs but retained the use of the *Seven Benefits* in the selection of transmission facilities to meet the identified needs in the long-term plans.

25 FERC also recognized, but did not mandate in Order 1920, additional benefits of transmission investment beyond these seven mandated. They include: (8) diversification of weather and load uncertainty; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12) increased market liquidity.

26 Traditional wires-based solutions include enhancing the transfer capability of a path by increasing the number of circuits, raising the voltage level of existing lines through reconductoring, or building new lines for a new path.

27 FERC Order 1920-A, available at: https://www.ferc.gov/news-events/news/presentation-order-no-1920-building-future-through-electric-regional-transmission.

scenarios and the selection of transmission facilities (including the solution selection criteria that are filed at FERC) and allow RSEs to request additional scenarios (which transmission providers must analyze as long as such scenarios are reasonable).[28]

Order 1920-A further allows for an extension of the timeline for RSEs and stakeholders to reach agreements on cost-sharing for regional projects, fostering better collaboration. For ATTs, this expanded involvement is critical, as the buy-in of states is often necessary to deploy GETs and HPCs effectively and to align their use with the RSEs' priorities, which include mitigating rate shocks. Order 1920-A confirms that Order 1920 does not restrict the transmission providers from considering benefits and ATTs that are not specified in Order 1920.

C. Overview of GETs and HPCs

Advancements in material science, power electronics, communication devices, computational processing power, and optimization algorithms has led to the development of various technologies designed to aid the operational efficiency and capabilities of the transmission grid. GETs and HPCs are two such technologies that have been recognized in recent FERC Orders.

GETs can be defined as hardware, software, or a combination of both that dynamically increase the capacity, efficiency, reliability, or safety of the power system (primarily focused on lines) faster and at a lower cost than traditional wires-based solutions. Many GETs are portable, and their installations are reversible. These characteristics of GETs, combined with their lower costs, make them a less risky investment when compared to large and permanent (i.e., irreversible) infrastructure investments.

HPCs are advanced transmission conductors engineered to carry higher power loads with reduced thermal sag, improved efficiency (i.e., lower losses), and greater resilience compared to traditional conductors. These advanced conductors often use carbon and/or composite cores instead of the steel wire cores used for conventional conductors. One of the benefits of deploying HPC technologies is that they often use the same rights-of-way for a given transmission corridor and the existing transmission towers to transfer much more power (50% to 100% more than the conventional conductor, and even more with some newer HPC technologies including superconductors).[29]

This leads to a shorter installation schedule than expanding the transmission path using traditional wires-based solutions while providing a much larger transfer capacity. While in-kind replacement of conventional steel-core conductors also increases transfer capacity by 30% or so – compared to the existing line that was installed 50 or more years ago – they should not be classified as HPCs. Instead, it should be recognized that HPCs are materials or designs that provide substantial and transformative improvements in power transfer capacity and operational performance.[30] Order 1920 refers to GETs and HPCs together as ATTs. The specific ATTs addressed in Order 1920 are a subset of the full array of these technologies and include the following:

- ✓ Dynamic Line Ratings (DLR)
- ✓ Advanced Power Flow Control (APFC)
- ✓ Transmission Switching[31]
- ✓ Advanced Conductors

Order 1920-A confirms transmission providers are not precluded from considering other ATTs.

The four ATTs listed in Order 1920 are discussed next.

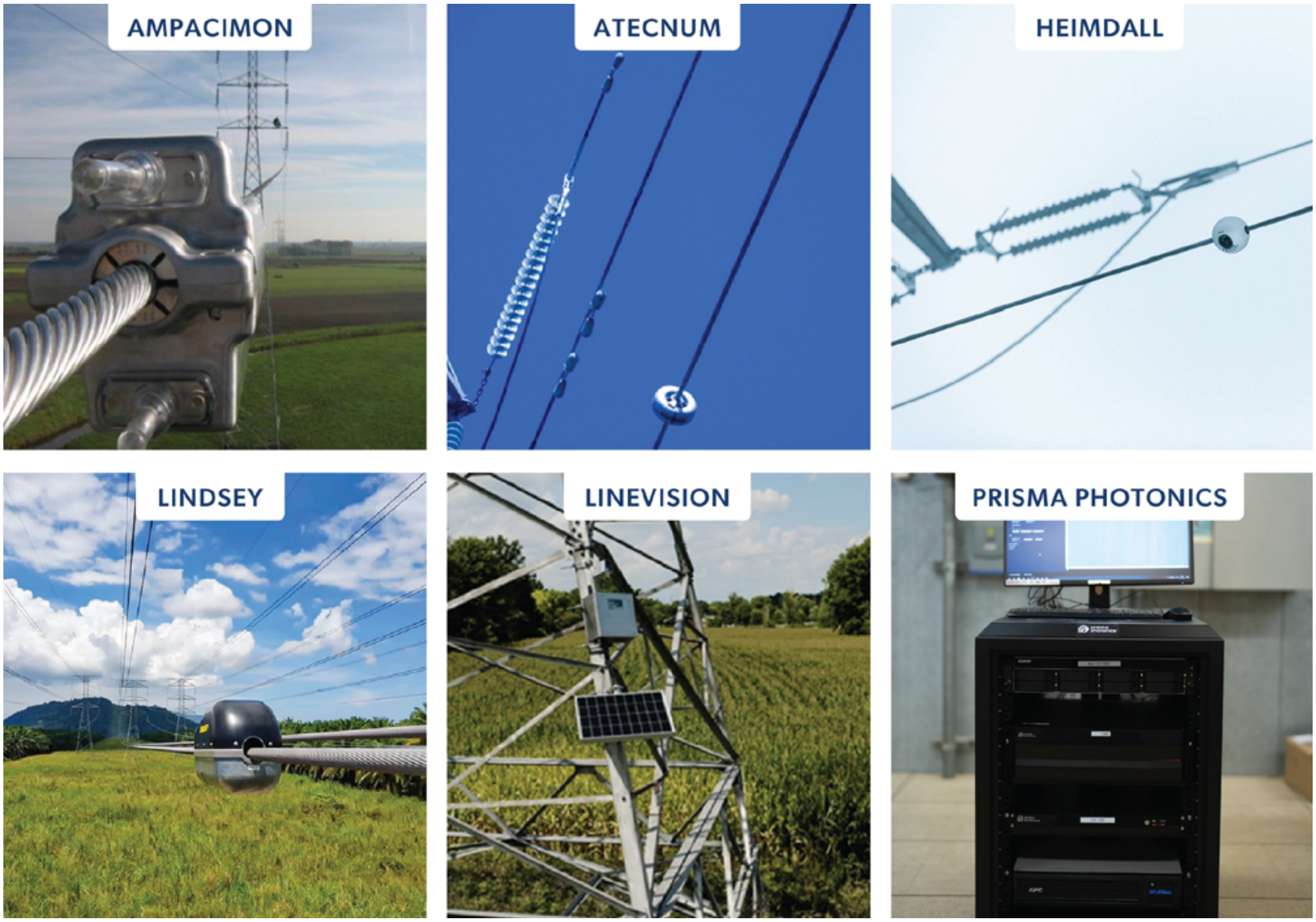
28 Such scenarios may incorporate additional factors that states see fit and do not need to include the full list of factors that FERC requires to be considered in the required three scenarios.

29 VEIR, a superconductor vendor, indicates 5x to 10x of transfer, compared to conventional conductors.

30 FERC, in Order 1920-A, did not specify HPCs. However, Orders 1920 and 1920-A do consider superconductors as HPC as they meet the Orders' requirements of reduced thermal sag, improved efficiency, and greater capacity.

31 In Order 1920, FERC differentiates between Transmission Switching and Topology Optimization, stating that Transmission Switching is specific to certain lines and is the act of "opening or closing transmission elements in pre-determined circumstances based on prior analyses well in advance of the operational time horizon," whereas Topology Optimization is the act of determining the optimal use of the system (i.e., identifying optimal reconfiguration/s, including Transmission Switching solutions). (Order 1920, page 1246.) This is analogous to differentiating between unit commitment decision software and unit commitment decision actions. In reality, the industry assumes that the unit commitment decisions are optimal or are at least informed by an optimization system. So, unless one wanted to expressly focus on out-of-merit commitment decisions by operators, which are typically costly and implemented only due to system needs not reflected in the unit commitment decision software, there is no practical difference. Likewise, Transmission Switching is, or should be, the implementation of actions identified with or informed by Topology Optimization.

FIGURE 4: DLR EQUIPMENT



Dynamic Line Rating systems monitor and adjust transmission line ratings in real-time based on measured sag of the lines, or calculations using measured environmental conditions, such as temperature, humidity, solar irradiance, wind speed and angle, and sometimes, vibration. These systems enable more efficient use of the transmission capacity by reflecting actual line conditions rather than conservative static line ratings (or ambient adjusted ratings, or AARs, as required by FERC starting in the summer of 2025) and typically come packaged with forecasting tools. The continuous monitoring also provides situational awareness benefits to grid operators. The specific technologies and measurement approaches used for DLR vary by vendor. Figure 4 shows various DLR equipment by vendors (Ampacimon, Atecnum, Heimdall, Lindsey, LineVision, and Prisma Photonics).

Advanced Power Flow Control uses modular devices to redirect power to the preferred (oftentimes underutilized) transmission lines, reducing congestion and improving overall grid utilization. It is akin to phase shifters (also known as phase angle regulators, or PARs), which are commonly used in the industry today, but has modularity benefits and provides more accurate active and reactive power flow controls with faster response times. Figure 5 shows APFC modules from Smart Wires.

Transmission Switching is an elegant approach to flow control. By analyzing the grid operations (including generation dispatch and load) and topology of the transmission network, in many cases through the usage of Topology Optimization software and tools, the pre-determined reconfigurations (i.e., opening and/or closing circuit breakers, therefore "Switching") are implemented to optimize power flow (through re-routing around bottlenecks) and reduce transmission congestion. Figure 6 illustrates how NewGrid's Transmission Switching helped reduce congestion and renewable curtailments in the Southwest Power Pool (SPP).

FIGURE 5: APFC MODULES (SMART WIRES)

FIGURE 6: TRANSMISSION SWITCHING (NEWGRID)

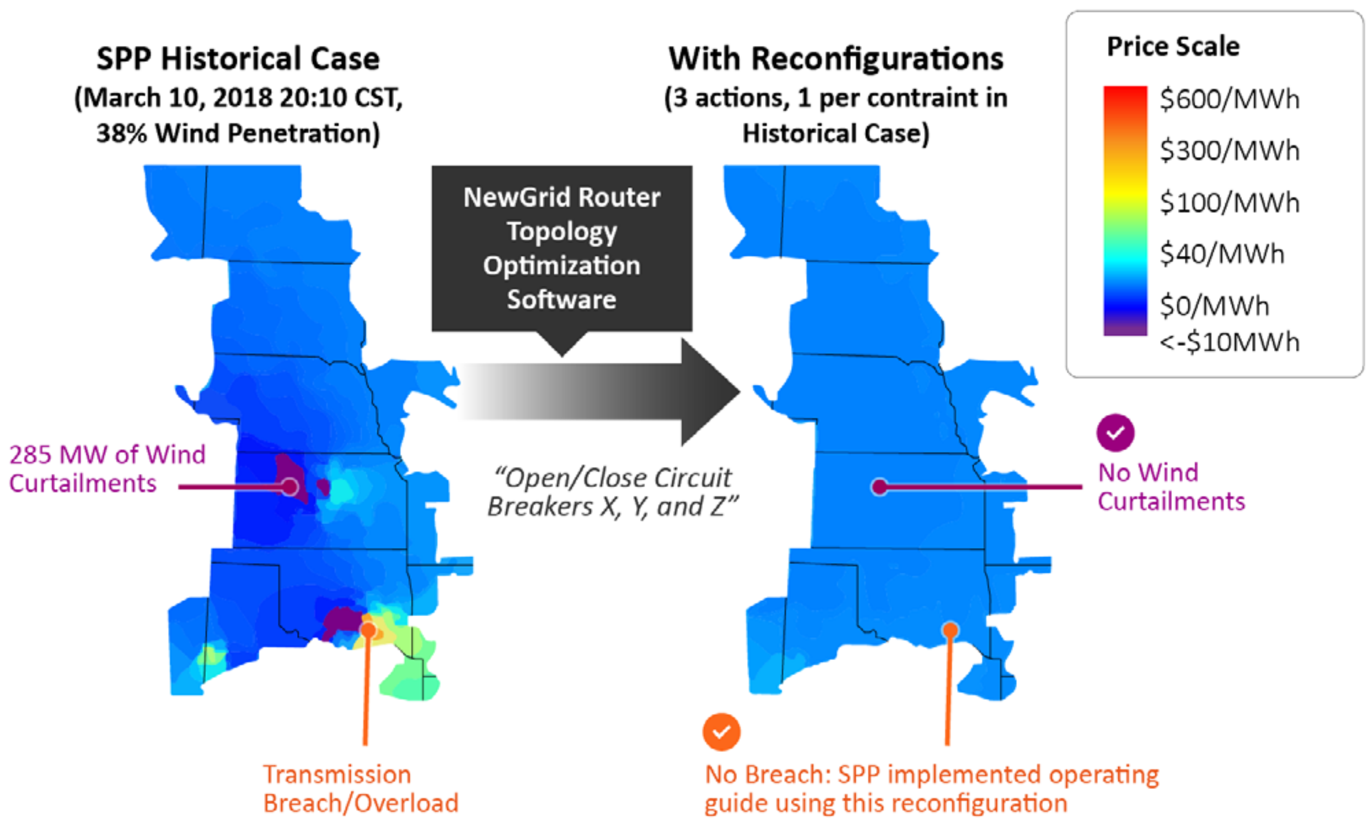
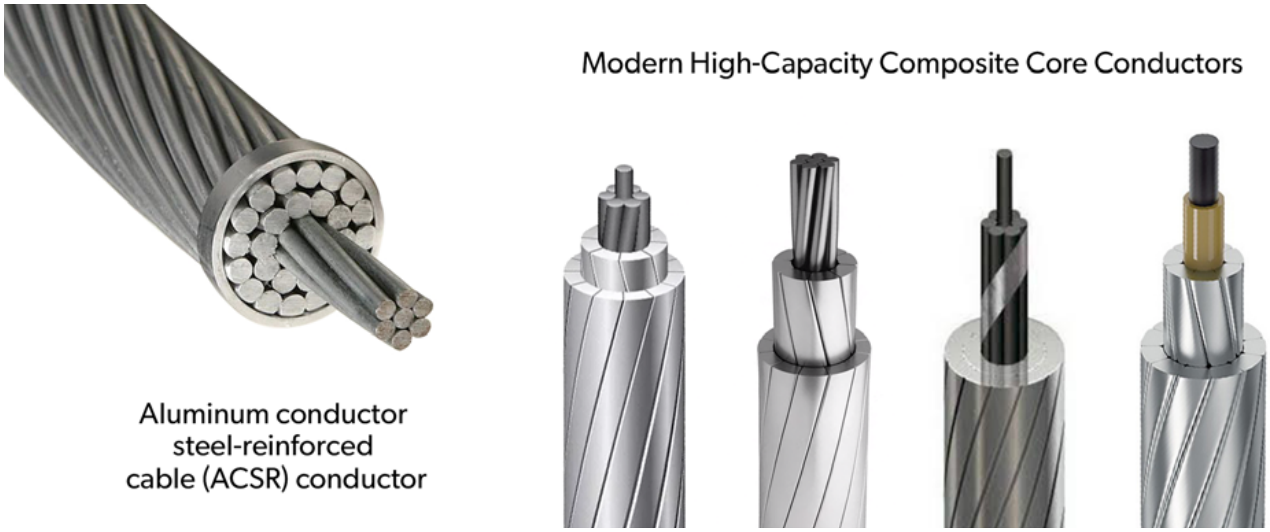


FIGURE 7: ADVANCED COMPOSITE CORE CONDUCTORS



Advanced Conductors, as defined by FERC in Order 1920, include, but are not limited to, advanced composite core conductors, advanced steel cores, high-temperature low-sag conductors, fiber optic temperature sensing conductors, and advanced overhead conductors. Orders 1920 and 1920-A also consider superconductors as HPCs since they meet the Orders' requirements for greater capacity.

Advanced carbon fiber and composite core conductors use carbon fiber or carbon composite cores (as the name suggests) to reduce line sag and increase transfer capacity without compromising mechanical strength. They are highly efficient in reducing line losses and have already been deployed by several US utilities. Figure 7 shows the four advanced composite core conductors commercially available in the US today.[32]

Superconducting cables (also known as high-temperature superconductors) employ superconducting materials to achieve ultra-low resistance transmission, enabling significantly higher capacity with minimal energy loss. To date, this technology has not yet been deployed commercially, but it is required to be studied as a part of long-term regional transmission planning and Order No. 1000 planning.

Appendix A: GETs and HPCs provide further descriptions of these technologies.

The most distinct characteristics of ATTs, when compared to the traditional wires-based solutions, are:

1. **Lower cost and speedier installation**: The costs of ATTs are lower than those of traditional wires-based solutions. The time needed to install them is also much shorter.

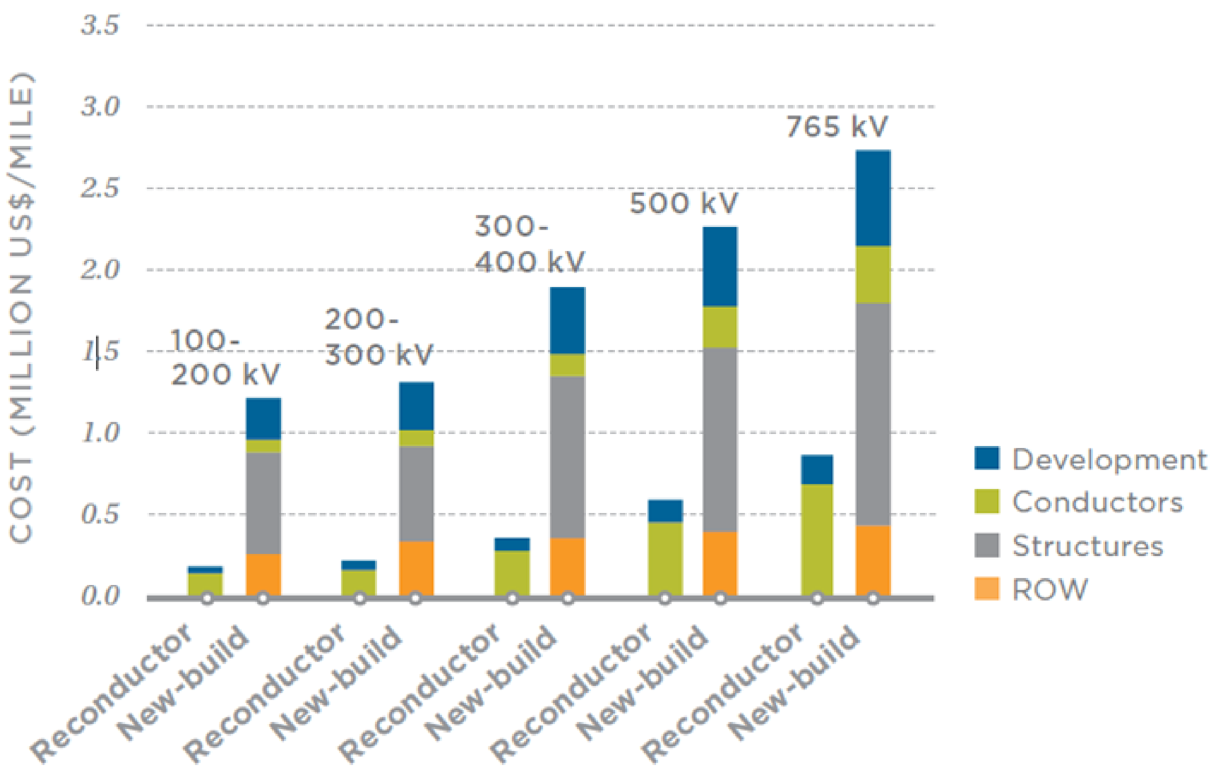
   GETs' costs are orders of magnitudes smaller than either of the wires-based solutions (i.e., conventional conductors and HPCs).[33] In many cases, the payback period of GETs is less than a year, making them a low-risk investment option. Installing GETs is also much faster, usually less than a year or two and sometimes within a few months. Additionally, many GETs, such as Transmission Switching or DLRs, can be implemented without outages, so there is no need to coordinate and schedule outages to tie in the new equipment to the grid.

   For HPCs, the costs of the conductors themselves may be higher than traditional conductors; however, the per-unit costs (e.g., $ per MVA of transfer capacity) may be

32 CTC Global, Wildfire Safety & Resiliency (Using Modified Structures and Carbon-Core Advanced Conductors), presented at the Montana Public Service Commission Information Session on January 28, 2025. The presentation recognizes four vendors: CTC Global, Epsilon, Southwire, and TS Conductor.

33 US Department of Energy, *Grid-Enhancing Technologies: A Case Study on Ratepayer* Impact (February 2022), https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf.

FIGURE 8: COST ESTIMATES OF NEW TRANSMISSION



lower. For expanding the transfer capacity of an existing path, the overall cost of an HPC solution – including all other components – is often lower because HPCs can reuse the existing transmission towers and do not require developing additional rights-of-way.[34]

Figure 8 shows the estimated costs of installing new lines. Reconductoring using existing towers and rights-of-ways can eliminate the two cost components (the structure represented in gray and the rights-of-ways represented in orange in Figure 8). Figure 9, meanwhile, compares the estimated costs between building new lines (represented in orange dots) and reconductoring (represented in blue dots).[35]

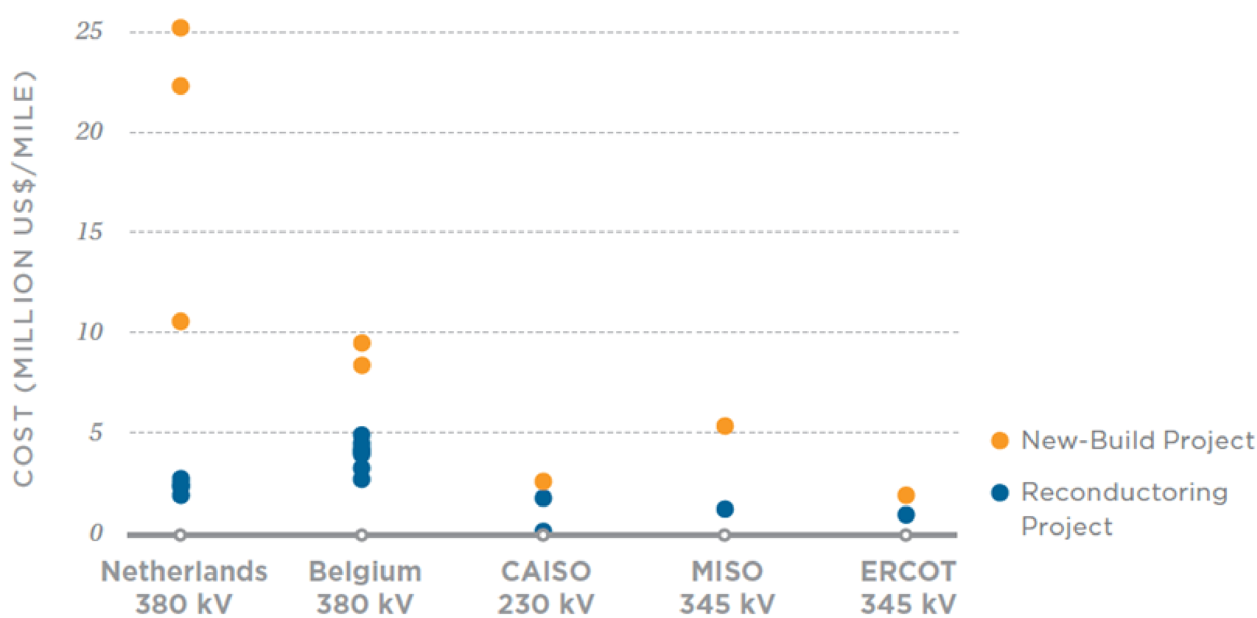
These attributes contribute to shorter (sometimes nearly half the time) schedules for reconductoring using HPCs compared to solutions relying on building new conventional conductors. If a new path is required, the smaller rights-of-way footprint and lower towers needed for HPCs often offset any cost disadvantages against conventional conductors.

2. **Complementarity to existing equipment**: ATTs are complementary to existing facilities. GETs – as the name implies – enhance transmission assets in many cases, whether they are existing or developed in the future, and rarely replace them. As an analogy, GETs are akin to a portable GPS in the car that allows the driver to get to the destination efficiently without expanding any roads. Building transmission lines (either conventional or HPCs), on the other hand, is akin to building new or widening existing roads. If the important factor is to allow the drive to be accomplished within a given amount of time, both solutions – GPS and roads – are complementary and not mutually exclusive. GETs alone will not replace the need for new transmission, just as a GPS will not

34 A study by Goldman School of Public Policy, University of California Berkeley and GridLab finds that replacing conventional lines with advanced conductors usually costs half as much as building new lines for the same capacity, partly because they re-use existing infrastructure. The study also estimates that 98% of US transmission lines are less than 50 miles long, which is ideal for reconductoring. See GridLab, *2035 and Beyond – Reconductoring Report* (2024), https://www.2035report.com/wp-content/uploads/2024/04/GridLab_2035-Reconductoring-Technical-Report.pdf.

35 GridLab, *2035 and Beyond – Reconductoring Report* (2024).

FIGURE 9: COST COMPARISON BETWEEN RECONDUCTORING AND BUILDING NEW TRANSMISSION



replace roads. At the same time, new transmission alone may not be the most efficient and effective solution, especially as it takes time to develop and construct new lines. HPCs – in particular, carbon fiber or carbon composite core conductors – often take advantage of their complementary characteristics and displace existing conventional conductors without altering existing towers and associated rights-of-way.

3. **Portability and reversibility**: This third characteristic is limited to GETs. GETs are portable, and their installations are reversible. When GETs installed at one location are not providing the anticipated level of benefits, or the need is no longer there (such as APFCs installed to avoid congestion during construction; see Section II.A: ATTs and *Seven Benefits* – *Benefit 5*: Reduced congestion during transmission outages), they can be removed altogether or relocated as needed. As discussed above, many GETs that involve hardware do not require outages for installation (or removal). HPCs and most traditional wires-based solutions are not portable nor easily reversible and are oftentimes referred to as "permanent solutions," indicating the investments are largely irreversible.

When combined, these characteristics (which are discussed further in Section IV: Considerations for Relevant State Entities) make ATTs a less risky investment compared to traditional transmission solutions. GETs' lower cost, faster installation, portability, and reversibility naturally make them a low-risk – hence lower-regrets – investment option.

Reconductoring with HPCs could also provide "right-sizing" (or "future-proofing") benefits by enabling extra transfer capacity that could be utilized later as future transmission usage increases (e.g., due to load growth). For reconductoring projects where the need is to replace aging facilities, using HPCs reduces the risk of unintended consequences, such as having to come back in a few years and reconductor again because of higher-than-anticipated load growth. This should be considered as an approach to "right-sizing" future investments rather than to build conservatively and regret it later. In the meantime, the excess capacity could provide additional reliability benefits through larger headroom. This allows flexibility for operators during highly constrained periods on the grid, such as during extreme weather events, and can ease the planning of various outages.

The relevance of ATTs (i.e., select GETs and HPCs) in Order 1920 mainly stems from their ability to address key root causes of inefficiencies in the US transmission system. A primary issue observed today is the misalignment between the rapid growth of transmission needs and the comparatively slow pace of transmission development, often hindered by regulatory delays and the complexity of interregional coordination, cost allocation, and obtaining permits from various jurisdictions needed to build new transmission, among other factors.

For example, building new transmission through the traditional wires-based solution typically takes five to 10 years or more, while new resources (subject to interconnection queue processes) and new loads such as data centers and cryptocurrency mining loads are developed in a much shorter timeframe – in many cases, in one to three years, or sometimes even quicker.[36] Another concern is the investment costs and bill impacts associated with new transmission.

As shown in Figure 1, the cost of replacing aging transmission facilities alone is estimated at $10 billion a year and will continue for at least the next decade.[37] The US Department of Energy's (DOE's) Energy Information Administration (EIA) observed through data collected over the past 20 years that spending on transmission nearly tripled over the past two decades, hitting $27.7 billion in 2023.[38] In the most recent year (from 2022 to 2023), EIA observed that capital investment in transmission alone increased by $2.7 billion (11%). The resulting higher costs not only adversely impact consumers but could lead to undermining or delaying policy goals and further create risks and challenges for both transmission-owning and dependent utility companies and their investors, such as through deteriorating utilities' credit ratings and limiting the amount of investments that can be financed.

Because of the three characteristics discussed above (lower cost and speedier installation, complementarity to existing equipment, and portability and reversibility), ATTs can provide cost-effective solutions in a shorter schedule than relying solely on the traditional wires-based solutions. Additionally, the fragmented nature of transmission planning and cost allocation often stalls large projects; HPCs, through reconductoring, can reduce the scope of new upgrades while GETs can offer incremental upgrades that align with the scenario-based, collaborative approach emphasized in Order 1920.

These factors indicate that the ATTs represented in Order 1920 need to be part of both short-term regional planning under Order 1000 and the long-term framework established by Order 1920.[39] Splitting the various transmission solutions into these two timeframes (or even more granular timeframes) will allow transmission providers to address challenges that span immediate needs and future goals. In the short term, GETs could offer flexible, cost-effective solutions to alleviate congestion and improve grid efficiency without the delays associated with large infrastructure projects. In the long term, both GETs and HPCs can play a critical role in modernizing the grid, integrating new technologies, and preparing for future demand and renewable energy growth in a cost-effective manner.

36 For example, Basin Electric Cooperative observed its cryptocurrency mining load grow from less than 5 MW in July 2022 to 200 MW in May 2023.

37 This provides an opportunity to "right-size" using HPCs rather than replace them with in-kind conductors.

38 US Energy Information Administration, "Today in Energy: Grid infrastructure investments drive an increase in utility spending over last two decades" (November 18, 2024), https://www.eia.gov/todayinenergy/detail.php?id=63724.

39 WATT Coalition, "FERC Order No. 1920-A Requires Grid-Enhancing Technologies in Transmission Planning," November 22, 2024, https://watt-transmission.org/ferc-order-no-1920-a-requires-grid-enhancing-technologies-in-transmission-planning/#:~:text=The%20order%20maintains%20the%20requirement,more%20cost%2Deffective%20than%20traditional.

II. Benefits of ATTs

A. ATTs and *Seven Benefits*

FERC Order 1920/1920-A asks transmission providers to consider *Seven Benefits* in their selection of facilities to meet the transmission needs identified in the long-term regional transmission planning processes. In this section, we discuss the *Seven Benefits* – introduced in Section I.B: FERC Order 1920 – and highlight 25 case studies to demonstrate how ATTs (limited to those listed explicitly in Order 1920) can achieve these *Benefits*. Some of the case studies demonstrate that ATTs can provide more than one *Benefit* within a given implementation.

Benefit 1: Avoided or deferred reliability transmission facilities and aging infrastructure replacement

Many studies have illustrated how ATTs can avoid or defer investments. GETs increase the usage of existing assets, which in turn could avoid or defer investments for new infrastructure. HPCs also reduce investments by extending the life of existing infrastructure. ATTs can also contribute to this *Benefit* in a rather indirect way, such as by reducing renewable curtailments and thereby eliminating (or delaying) the need to invest in new renewable resources and associated transmission infrastructure.

APFC and Transmission Switching – and the underlying Topology Optimization software used to identify Switching solutions – can avoid or defer the need for new reliability transmission projects through optimizing (i.e., redirecting) flows. They can also be used to identify ways to retire certain aging facilities without the need to replace them.

CASE STUDY 1: DNV-GL PJM STUDY

A 2016 study by DNV GL of the deploying APFC devices in the PJM system (assuming a future PJM system in 2026 with 30% of its energy sourced from renewable resources and adding APFC devices on select lines higher than 100 kV) observed that adding these Flexible Alternative Current Transmission Systems (FACTS)-based flow control devices reduced new line miles by 24% and reconductoring line miles by 45%, resulting in $267 million reduction in annual transmission spending.[40]

CASE STUDY 2: DOE LIFTOFF REPORT

The DOE's 2024 Pathways to Commercial Liftoff: Innovative Grid Deployment ("Liftoff Report") finds that GETs could increase the capacity of the existing grid to support 20 GW to 100 GW of incremental peak demand when installed individually, with significant additional capacity potential when different GETs technologies are installed in strategic

40 These values are expressed in 2026 dollars. Adding these FACTS-based flow control devices reduced new line miles by 24% and reconductoring line miles by 45%, leading to the $267 million drop in annual transmission spending

combinations.[41] DOE estimates this use of GETs could help defer an estimated $5 billion to $35 billion in transmission and distribution infrastructure costs over the next five years.

HPCs have also been proven to avoid infrastructure investments.

CASE STUDY 3: SCE HPC AND TRANSMISSION TOWERS

When Southern California Edison (SCE) rebuilt 137 miles of its Big Creek transmission corridor, SCE adopted HPC and used existing structures. Using existing towers contributed to reducing construction time from an estimated 48 months to 18 months while increasing the rights-of-way operating capacity by over 40%.[42] It also eliminated the replacement costs of towers, estimated at $50,000 per tower, while saving costs associated with permitting and environmental impact studies.

APFC, Line Switching, and, in particular, DLR systems, are recognized for reducing renewable curtailments (mostly wind).[43] In a future where renewables dominate the energy resource mix, leveraging ATTs to lower renewable curtailments could help avoid or defer the need for new generation and associated transmission facilities. This is particularly important when renewable energy policies are focused on maximizing energy produced by renewables (i.e., MWh) and, in turn, their capacity factor rather than their installed capacities (i.e., MW).

CASE STUDY 4: NEW YORK DLR

Actual DLR systems installed on two double-circuit 115 kV lines in upstate New York show how DLR avoided the need to rebuild 26 miles of transmission. This DLR project, along with five miles of circuit rebuilds, was projected to reduce renewable curtailments by over 350 MW while further increasing the transfer capacity of the circuits by an additional 190 MW. 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.

CASE STUDY 5: DOE GETS REPORT

Implementing ATTs is not limited to a single technology type. A DOE case study of the use of GETs indicates that the combination of DLR and APFC could double the amount of avoided renewable curtailments when compared to implementing the technologies individually, further contributing to this *Benefit*.[44]

Similarly, HPCs carry more current than traditional conductors, increasing the capacity of existing transmission lines, reducing energy losses, and avoiding the need for new infrastructure. This includes eliminating the need for taller towers required for larger conventional wires operating at higher voltages or adding parallel circuits of conventional wires along the same path.

Benefit 2: Reduced loss of load probability or reduced planning reserve margin

ATTs can reduce loss of load probability (LOLP) or lower the planning reserve margins (which are two sides of the same coin, as Order 1920-A recognizes). The contribution of ATTs to these *Benefits* is more apparent during adverse system conditions.

CASE STUDY 6: 2018 "BOMB CYCLONE" AND DLR

The extended cold snap that occurred during the 2018 "Bomb Cyclone" constrained much of the grid in the northeastern US. During this extreme weather event that occurred between late December 2017 and January 2018, ISO New England (ISO-NE) issued an abnormal conditions alert to address both the weather and supply concerns and increased their transmission line ratings to allow for greater line capacity. One ISO-NE report stated, "At 16:00 on 1/3/18, the scheduling limit on the New York A.C. ties was increased from 1,400 to 1,600 MW. The increased limit was made possible by the cold conditions, which helped to improve thermal transfer

41 US Department of Energy, "Pathways to Commercial Liftoff: Innovative Grid Deployment" (April 2024), https://liftoff.energy.gov/wp-content/uploads/2024/05/LIFTOFF_Innovative-Grid-Deployment_Updated-2.5.25.pdf.

42 CTC Global, "SCE Sag Mitigation Case Study," https://ctcglobal.com/sag-mitigation-case-study/.

43 Deployments in Europe indicate DLR will typically reduce wind curtailments by 15% to 20% or more.

44 US Department of Energy, *Grid-Enhancing Technologies*.

capability."[45] The situational awareness helped ISO-NE avoid large quantities of congestion as power flows increased to meet the demand created by the bomb cyclone and mitigate potential service interruptions (or, in other words, reduce the LOLP).[46] This example also applies to the sixth benefit (mitigation of extreme weather events and unexpected system conditions) discussed later.

There are other usages of GETs to reduce LOLP.

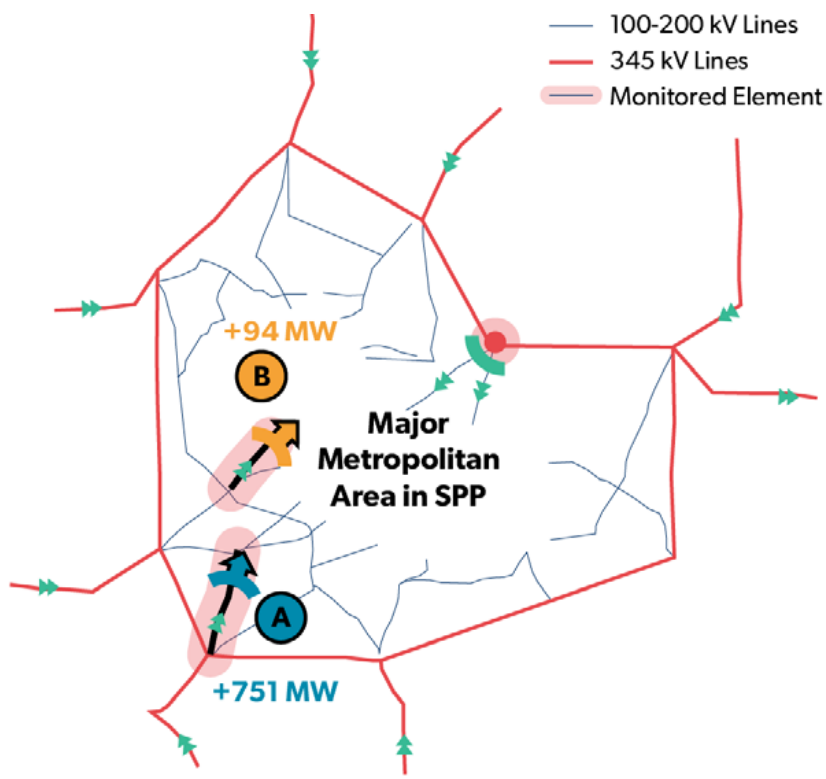
CASE STUDY 7: SPP WINTER STORM JUPITER

In 2018, SPP analyzed the benefits of flow control using Transmission Switching to heat lines during severe winter conditions to avoid icing. The study was performed using the January 2017 Winter Storm Jupiter conditions, when ice accumulation caused multiple transmission outages. The challenging conditions for restoration led to some outages lasting over a full day. The study identified two Transmission Switching solutions that could have prevented or significantly relieved the ice buildup on selected critical lines while meeting reliability criteria. If implemented, this would have reduced the loss of load.

CASE STUDY 8: SPP WINTER STORM ELLIOT

During emergency conditions under Winter Storm Elliott in 2022, SPP implemented two Transmission Switching solutions. The solutions increased transfer capacity into a major metropolitan area and released up to 845 MW of available but otherwise stranded generation, reducing the loss of load probability significantly during the storm. The Transmission Switching enabled 14 GWh of power to flow into the otherwise congested area. Two additional Transmission Switching solutions could have further increased transfer capability and released up to 600 MW of additional generation to the system, potentially releasing an additional 9 GWh of power. Figure 10 shows the two Transmission Switching solutions implemented by SPP.[47]

FIGURE 10: COST ESTIMATES OF NEW TRANSMISSION



45 See slide 41 of ISO-NE presentation "Cold Weather Operations, December 24, 2017–January 8, 2018" available at: http://www.nepool.com/uploads/NPC_20180112_Cold_Weather_Ops.pdf.

46 Technically, ISO-NE used ambient-adjusted line ratings (AAR) rather than DLR.

47 Provided by NewGrid.

As these examples show, a catalog of Transmission Switching options (identified in advance using Topology Optimization software to perform predictive analytics) can optimize grid operations and maintenance schedules, thereby improving reliability and reducing the LOLP.[48]

CASE STUDY 9: HPC DESIGN AND HISTORY

Many HPCs were developed partially in response to the major East Coast blackout of 2003, which was caused by excessive conductor sag. Immediately after this cause of the blackout was identified, several vendors introduced high-capacity low-sag conductors.[49] These conductors were designed to use composite cores to carry higher currents without exhibiting excessive conductor sag or suffering from excessive line losses. This underlying design of many HPCs reduces one potential cause of loss of load.

Benefit 3: Production cost savings

Increased line limits (through HPC or DLR) and system controllability (through APFC and Transmission Switching) can reduce congestion and improve the efficiency of power flow, resulting in lower electricity production costs. Various studies indicate such savings would be in the range of tens to hundreds of millions of dollars a year for the given region, if not more. The study results indicate nationwide savings to be in the billions of dollars per year.

CASE STUDY 10: BRATTLE SPP GETS STUDY

A 2021 study by The Brattle Group (Brattle) indicates deploying three types of GETs (DLR, Transmission Switching, and APFC) in the Kansas and Oklahoma region of SPP can integrate twice the amount of renewables compared to the case without GETs, resulting in an annual production cost savings of $175 million for a $90 million investment (or payback in roughly half a year). This translates to over $5 billion for the lower 48 states.[50]

CASE STUDY 11: RMI PJM GETS STUDY

A 2023 study by the Rocky Mountain Institute (RMI) showed that deploying the same three types of GETs across 95 transmission projects in PJM could yield $1 billion in annual production cost savings, largely by optimizing dispatch and minimizing the curtailment of renewables.[51] Scaling the results (based on energy served) indicates production cost savings for the lower 48 states through the deployment of these three GETs would add up to $5 to $6 billion a year.

Various studies also indicate the benefits of individual GETs.

CASE STUDY 1: DNV-GL PJM STUDY – REVISITED

The aforementioned DNV GL PJM Study that evaluated APFCs in a future PJM system with a 30% renewable penetration level calculated PJM region-wide production cost savings of $623 million per year. The estimated investment cost was $81 million, indicating an 11x payback within one year or a payback period of roughly one month. DNV GL observed there may be further savings, such as the potential to reduce up-front interconnection costs for renewable resources.

CASE STUDY 12: TRANSMISSION SWITCHING STUDIES

Studies of Transmission Switching using Topology Optimization software found annual production cost savings in Real-Time markets to be over $100 million for PJM, $18 to $44 million for SPP, and £14 to £40 million (approximately

48 Order 1920 does not count Topology Optimization software as one of the ATTs.

49 CTC Global, "High-Performance Transmission Conductors: Improving Grid Efficiency" (May 1, 2020), https://ctcglobal.com/high-performance-transmission-conductors-improving-grid-efficiency/.

50 The Brattle Group, *Unlocking the Queue with Grid-Enhancing Technologies* (February 2021), https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

51 RMI, "GETting Interconnected in PJM: Grid-Enhancing Technologies (GETs) Can Increase the Speed and Scale of New Entry from PJM's Queue" (2024), https://rmi.org/insight/analyzing-gets-as-a-tool-for-increasing-interconnection-throughput-from-pjms-queue/.

$18 to $52 million) for Great Britain.[52] If Switching were performed for the Day-Ahead market, the annual production cost savings for PJM is estimated to increase by almost 1.5 times to $145 million.

CASE STUDY 13: GRE DLR

Actual DLR systems deployed by Great River Energy (GRE) on nine lines also show significant production cost savings. On a day in July 2024 when wind generation in real-time exceeded the forecast amount, the production cost benefits provided by the installed DLR systems for a single hour (3 p.m.) was estimated to be over $3 million, which more than paid for the entire DLR investments.[53]

Various European examples, including actual DLR deployment experience, indicate a 15% to 20% reduction in wind curtailment, leading to significant production cost savings. The benefits are not limited to reductions in renewable curtailments.

CASE STUDY 14: ELIA DLR

The Belgium transmission system operator Elia deployed DLR system-wide with over 150 sensors installed on 30 transmission lines, which helped Elia increase exchange capacities with surrounding countries (France, Netherlands, Luxembourg, and Germany). Elia identified over $0.26 million of congestion savings provided by DLR during just a four-hour instance of congestion by allowing for the additional import of 33 MW. If similar congestion patterns were to be observed 10% of the time, this would add up to $50 million in annual savings.

Benefit 4: Reduced transmission energy losses

EIA estimates that, from 2018 to 2022, annual electricity transmission and distribution (T&D) losses averaged about 5% of the electricity transmitted and distributed in the United States.[54] ATTs, particularly HPCs, are designed to reduce transmission losses. Whether composite or carbon core conductors, HPCs can decrease losses by at least 20% and typically up to 40% or more depending on the electrical load being carried (which impacts the conductors' temperature as higher flows will warm the conductor more). Figure 11 illustrates the difference in losses by conductor type.[55] The figure shows line sags and temperature with the flow at all the endpoints being 1500 amps. Higher temperature indicates higher conductor resistance, which leads to line losses.

CASE STUDY 15: HYDRO QUEBEC CONDUCTORS COMPARISON

A 2005 comparison test on a number of conductor types performed by Hydro Quebec shows that the Aluminum Conductor Composite Core (ACCC) conductor exhibited the least thermal sag and ran 60 to 80 degrees Celsius cooler than any of the other equivalent-sized conductors tested. The cooler temperature is a direct reflection of improved efficiency, as less energy is lost to heat.[56] Superconductors have been shown to reduce losses further by between 50% and 80%.[57]

GETs, by optimizing voltage and current flows, can also reduce losses, although to a lesser degree than HPCs.

52 Electric Reliability Council of Texas (ERCOT), "Transmission Topology Optimization Software" (December 2016), https://www.ercot.com/files/docs/2016/12/01/05._Transmission_topology_control_--_ERCOT_ETWG_12616.pdf, and NewGrid, "Topology Optimization Case Studies (May 2024), https://newgridinc.com/wp-content/uploads/2024/05/topology-optimization-case-studies.pdf

53 Great River Energy, "Dynamic Line Ratings" (October 2024), presented at the 15th Annual Colorado Rural Energy Association Energy Innovations Summit.

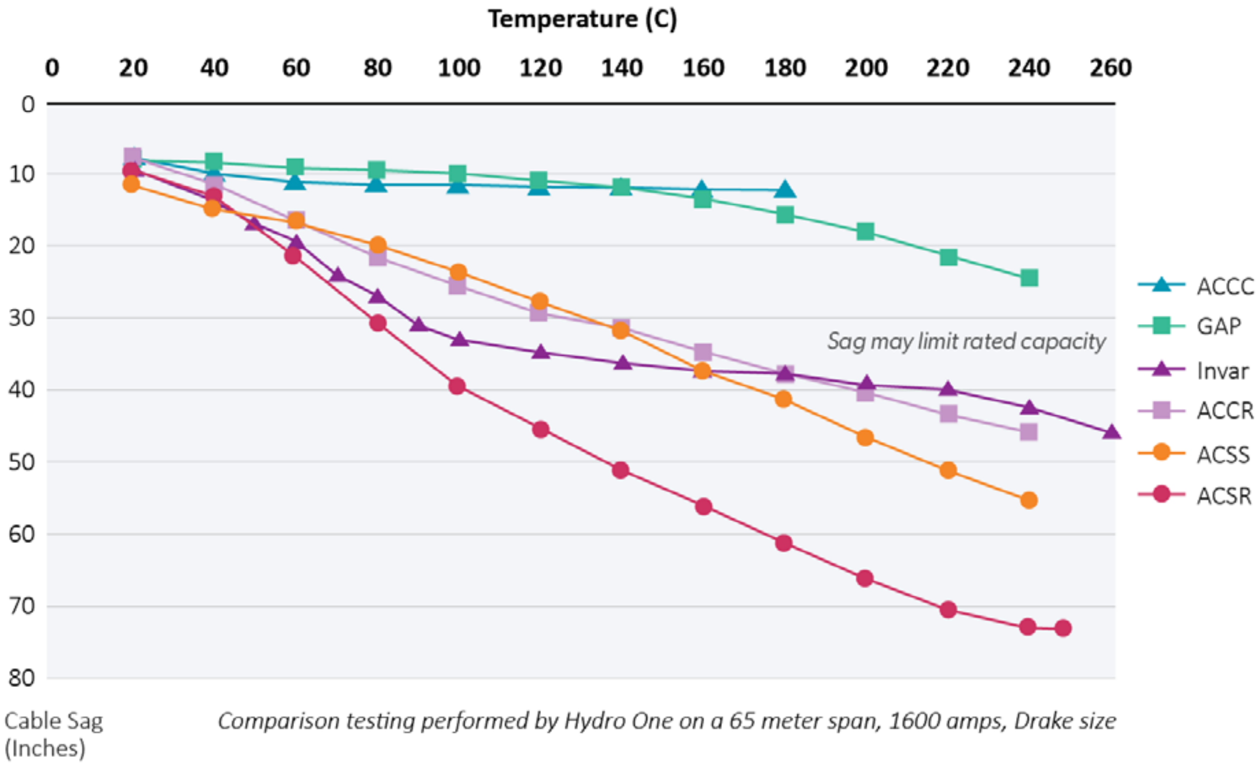
54 US Energy Information Administration, "FAQs: How much electricity is lost in transmission and distribution in the United States?" https://www.eia.gov/tools/faqs/faq.php?id=105&t=3.

55 CTC Global, "CTC Global ACCC Conductor – Reducing Line Losses," https://ctcglobal.com/accc-conductor-reduces-line-losses-everyone-care/.

56 The test ran 1,600 amps through "Drake" size conductors to assess their sag characteristics. See: CTC Global, "CTC Global ACCC Conductor – Reducing Line Losses."

57 VEIR's high-temperature superconducting electric transmission lines have negligible losses. These lines can operate with 5 to 10 times the transfer capacity of conventional lines for a given voltage level.

FIGURE 11: CONDUCTOR PERFORMANCE COMPARISON



Comparison testing performed by Hydro One on a 65 meter span, 1600 amps, Drake size

CASE STUDY 10: BRATTLE SPP GETS STUDY - REVISITED

The aforementioned Brattle study shows that GETs installed on the Kansas and Oklahoma grids could increase the utilization of the existing 345kV lines by 15% to 22%, resulting in a reduction in losses from power flowing through lower voltage lines.[58]

However, the evaluation of this *Benefit* requires further consideration of the totality of all *Seven Benefits*. For example, if the selected transmission solution provides for greater utilization of a line (e.g., through incorporating GETs) with access to lower-cost resources located farther from load, the overall transmission losses may go up as a result of the greater distance between the resource and load. The larger reduction in production cost associated with this solution will likely outweigh the disadvantage of increased losses.

Benefit 5: Reduced congestion due to transmission outages

ATTs can play a significant role in achieving this *Benefit*. Both HPCs and DLR can reveal additional capacity on adjacent or interconnected lines, enabling system operators to reroute power efficiently and reduce congestion that could otherwise occur near the outaged facility. APFC and Transmission Switching could also help system operators route power away from the outage-effected area and thereby contribute to similar *Benefits*.

CASE STUDY 16: APFC 2015

In 2015, an APFC vendor analyzed the potential benefits of APFCs to support the construction of new transmission lines. The utility wanted to upgrade two 60 kV lines, both to 115 kV. Given the length and location of the lines (70 miles long over difficult terrain) and the need to replace the towers (from wood poles to steel towers), the estimated construction period was three and a half years. Taking out the two 60 kV lines required redispatch of generation, particularly in the summer season,

58 WATT Coalition, "Benefits of ATTs Compared to Traditional Upgrades" (2024), https://watt-transmission.org/wp-content/uploads/2024/08/WATT-and-AMP-Benefits-of-ATTs-compared-to-traditional-upgrades.pdf.

to avoid overloading other nearby lines. The study found that the redispatch could be avoided by installing APFC devices and rerouting the flow from these otherwise overloaded lines. The annual costs of the APFC devices were estimated to be between $1.5 million and $4 million. The savings from avoiding redispatch were estimated to be over $20.5 million a year, therefore suggesting a net savings of $61.5 million to $69.7 million over the construction duration period of three and a half years (depending on when the construction starts).

CASE STUDY 17: EPM AND APFC

Empresas Públicas de Medellin (EPM) of Colombia 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 was forecasted to grow strongly.[59] EPM needed a grid upgrade option that could quickly resolve the congestion at the lowest cost to consumers and with minimal impact on local communities.

EPM evaluated several network options, including reconductoring the transmission corridor with conventional conductors, which would increase the capacity of the transmission corridor but could be costly and take several years to complete, including the lengthy permitting processes. This reconductoring option with conventional conductors would also reduce grid capacity during its construction as the line would be out of service. After estimating two to two and a half years for reconductoring, depending on outage coordination, EPM decided to use APFC devices at two substations, providing the capability to revert power away from the overloaded line and onto underutilized lines. Construction of the APFC devices is estimated to take nine months, with an outage time of less than a week for commissioning. EPM recognizes the benefit of scaling up the deployments or relocating the APFC devices to an alternate location as system needs change over time.

CASE STUDY 18: TRANSMISSION SWITCHING FOR OUTAGES

In 2018, Brattle conducted an analysis for a G&T electric cooperative within a regional transmission organization (RTO) market. Due to planned four-month-long transmission outages, the electric cooperative's main power plant was subject to severe congestion that limited its output and reduced its nodal prices compared to the electric cooperative's load center. Using Topology Optimization software, Brattle identified Transmission Switching solutions that would fully mitigate this congestion.

The electric cooperative discussed the solutions with the RTO staff, who validated the Switching solution and its benefits. However, the solution was not implemented as the owner of the transmission assets to be switched declined to do so, arguing that the outages that caused the congestion were not located within their footprint. Since the solution was not implemented, the electric cooperative members incurred about $4 million in congestion costs during the four-month transmission outage period.

The Topology Optimization software used to develop Transmission Switching solutions (in many cases to mitigate transmission congestion) could be applied in alternative ways that provide additional benefits. The software technology, designed to analyze changes in topology (such as through Transmission Switching), can be used to analyze the impact of adding or removing a line or a group of lines; this, in turn, provides unique applications, such as evaluating the impact of transmission outages (for outage planning).

Benefit 6: Mitigation of extreme weather events and unexpected system conditions

ATTs can play a significant role in mitigating unexpected system conditions, including those caused by extreme weather events. Both HPCs and GETs can reveal additional capacity on adjacent or interconnected lines, enabling system operators to reroute power efficiently and deal with unexpected system conditions, including those associated with extreme weather events.

59 ElectricNet, "Empresas Públicas de Medellin (EPM) Announces Successful Effort Leveraging Modular FACTS" (March 10, 2021), https://www.electricnet.com/doc/empresas-publicas-de-medellin-epm-announces-successful-effort-leveraging-modular-facts-0001.

CASE STUDY 6: 2018 "BOMB CYCLONE" - REVISITED

The DLR application during the 2018 "Bomb Cyclone" discussed earlier for the second *Benefit* (reduced loss of load probability or reduced planning reserve margin) highlights how DLR – or HPC – could help during extreme weather conditions by securing additional capacity.

CASE STUDY 19: PJM WINTER STORM ELLIOT

PJM, in its January 2024 supplemental comments to FERC in the DLR Notice of Inquiry, emphasized the value of several DLR deployments during Winter Storm Elliot, stating, "The DLR ratings on this line during the storm proved higher than the ambient adjusted ratings PJM would have operated to otherwise. Had PJM not had the higher dynamic line ratings, PJM would have had to take action to re-dispatch the system to maintain reliability. Such action would have been very difficult under the critical operating conditions."[60]

APFC and Transmission Switching could also help system operators by enabling real-time adjustments to power flows and improved flexibility during extreme weather events or sudden system disruptions. Some of these are in response to unexpected system conditions, while others can be prevention activities.

CASE STUDY 7: SPP WINTER STORM JUPITER - REVISITED

SPP analyzed the benefits of flow control using Transmission Switching to heat lines to avoid icing for the January 2017 Winter Storm Jupiter conditions. The study identified two Switching solutions that could have prevented or significantly relieved the ice buildup on selected critical lines and avoided the outages. The estimated savings of avoiding the outages of these critical lines were $10 to $17 million, in addition to avoided system restoration costs.[61]

CASE STUDY 8: SPP WINTER STORM ELLIOT - REVISTED

During emergency conditions under Winter Storm Elliott in 2022, SPP implemented two Transmission Switching solutions to increase transfer capacity into a major metropolitan area, which released up to 845 MW of available but otherwise stranded generation. Two additional Transmission Switching solutions would have further increased transfer capability and released up to 600 MW of additional generation to the otherwise congested area.

The same Topology Optimization software used to develop Transmission Switching options can be used preventively to identify 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) in advance of any significant event. The combination of DLR and APFC or Transmission Switching options (identified through Topology Optimization software) could also be used to mitigate potential wildfires. If the situational awareness provided by DLR indicates higher threats of wildfires, system operators can route flow away from such areas by using APFC or Transmission Switching options, potentially to lines with higher transfer capability enabled by DLR or HPC.

The potential for such extreme events could justify installing DLR on most lines because the benefits that come from the situational awareness provided by DLR during one or two of such events could be sufficient to exceed the DLR costs. The same can be said for the Topology Optimization software that develops Transmission Switching solutions because of the optionality it provides at the fairly low cost of the software.

HPCs with a stronger core (compared to conventional steel core conductors) have demonstrated their "extreme weather-proofness" in various jurisdictions.[62]

60 PJM Interconnection, "Comments to FERC Docket No. AD22-5-000" (January 17, 2024), https://www.pjm.com/-/media/DotCom/documents/ferc/filings/2024/20240117-ad22-5-000.ashx.

61 See Ruiz P., et al., "Transmission topology optimization: pilot study to support congestion management and ice buildup mitigation," SPP Technology Expo (November 2018).

62 Many superconductors are buried underground. VEIR's overhead superconductor will be encased. These designs remove exposure to ambient conditions and bolster their "extreme weather-proofness."

CASE STUDY 20: NEVADA ENERGY HPC

In 2010, a 100-mile-per-hour windstorm in southern Nevada uprooted many of the wood structures supporting the power lines. Guy-wires placed on the structures prevented them from completely toppling over but still placed extra strain on the ACCC cables. The local utility, Nevada Energy, was able to repair all towers and continued using the existing ACCC cables with no adverse events.

Then, in January 2012, a fire-storm swept through the area, burning down 27 wood structures in their system, four of which belonged to the ACCC span from Reno to Carson City. After inspecting the damage, the cables seemed to be unharmed despite the fires completely burning the wood structures. The utility rebuilt the wood structures and continues to use the original ACCC to this day. Since these early wins, Nevada Energy continues to install additional ACCC throughout its system.[63]

CASE STUDY 21: OKLAHOMA GAS AND ELECTRIC HPC

In May 2013, an Enhanced Fujita scale (EF) 5 tornado with an estimated peak wind speed exceeding 200 miles per hour struck the Oklahoma Gas and Electric (OKGE) service territory.[64] The storm damaged the aluminum strands on the HPCs in several areas. OKGE suspects that a 40-foot shipping container flew into the steel monopole (140 feet high) and bent the lattice structure at the middle to an angle of approximately 45 degrees at ground level, as shown in Figure 12. Yet, the composite core of the HPC that OKGE installed in 2006 was not damaged and continued to support the monopole with its tension. The damaged conductor staying in the air helped simplify and expedite repairs.

FIGURE 12: BENT LATTICE STRUCTURE SUPPORTED BY HPC

CASE STUDY 22: CALIFORNIA WILDFIRE AND HPC

In California, where the risk of wildfires is a constant concern, utilities have utilized HPCs to help reduce the likelihood of sparks caused by power lines during high winds and dry conditions. The increased strength and fire resistance of HPCs has contributed to fewer fire incidents and improved safety in vulnerable areas.[65]

CASE STUDY 23: CANADA ICING AND HPC

In Canada, HPCs are deployed in regions prone to freezing rain and ice storms, where traditional power lines are often damaged by the weight of ice accumulation. HPCs' ability to withstand these harsh conditions has helped maintain power delivery to remote communities during winter storms.

CASE STUDY 24: SOUTHEASTERN US AND HPC

In the Southeastern US, where hurricanes and tropical storms frequently cause widespread power outages, utilities have replaced outdated infrastructure with HPCs. HPC's conductor strength and resistance to wind damage make it ideal for these storm-prone regions, helping utilities keep power flowing during extreme weather events.

63 Idaho National Laboratory, *Advanced Conductors Scan Report* (September 2024), https://inl.gov/content/uploads/2024/10/23-50856_R12a_-AdvConductorsScanProjectReportCompressed.pdf.

64 Electric Energy Online, "OG&E Takes a Hard Hit from a Series of EF4 and EF5 Tornadoes" (July/August 2013), https://electricenergyonline.com/energy/magazine/717/article/OG-E-Takes-a-Hard-Hit-from-a-Series-of-EF4-and-EF5-Tornados.htm.

65 CTC Global, "How CTC Global's ACCC Conductor Is Helping Utilities Prepare for and Endure Extreme Weather Events" (November 15, 2024), https://ctcglobal.com/how-ctc-globals-accc-conductor-is-helping-utilities-prepare-for-and-endure-extreme-weather-events/#:~:text=While%20traditional%20power%20lines%20often,reduced%20maintenance%20costs%20over%20time.

Benefit 7: Capacity cost benefits from reduced peak energy losses

ATTs can play a significant role in reducing peak energy losses. As discussed in the *Benefit 4* (reduced transmission energy losses) examples, HPCs and DLRs can reveal additional transfer capacity on interconnected lines while reducing losses.

APFC and Line Switching could also increase import limits to areas with higher capacity costs, leading to capacity cost *Benefits*.

CASE STUDY 25: NEW YORK PHASE ANGLE REGULATORS

Phase angle regulators (PARs) that lie at the border of New York ISO (NYISO) and PJM, right near New York City, were adjusted to reduce the Locational Minimum Installed Capacity Requirements (LCRs) for the New York City zone (Zone J) within NYISO.

NYISO's AC project, which was constructed to increase the flow limits between upstate New York (UPNY) and southeast New York (SENY), provides another example that is provided by PARs. The AC project was designed to increase the UPNY/SENY flow limits from 5,250 MW to 7,150 MW. However, the construction delay of the Dover PAR reduced that amount.[66] An increase in the UPNY/SENY interface allows for the New York system to import more capacity from the lower-cost UPNY to the higher-cost SENY and reduce the LCR for the Lower Hudson capacity zone. In this example, completion of the PAR would have increased the UPNY/SENY interface and thereby lowered the cost of securing capacity in SENY. While these examples are for PARs, APFC and, to some degree, Transmission Switching could provide similar *Benefits*.

B. Observations and Recommendations

The previous section demonstrated through various case studies how well ATTs perform when evaluated according to the *Seven Benefits* outlined in Order 1920 (listed again below).

- ✓ ***Benefit 1***: Avoided or deferred reliability transmission facilities and aging infrastructure replacement
- ✓ ***Benefit 2***: Reduced loss of load probability or reduced planning reserve margin
- ✓ ***Benefit 3***: Production cost savings
- ✓ ***Benefit 4***: Reduced transmission energy losses
- ✓ ***Benefit 5***: Reduced congestion due to transmission outages
- ✓ ***Benefit 6***: Mitigation of extreme weather events and unexpected system conditions
- ✓ ***Benefit 7***: Capacity cost benefits from reduced peak energy losses

Figure 13 summarizes the 25 ATT case studies and the *Benefits* – numbered 1 through 7, corresponding to the above list – they provide.

Figure 14 contrasts the 25 ATT case studies with the three core characteristics of the ATTs (lower cost and speedier installation, complementarity to existing equipment, and portability and reversibility).

66 New York State Reliability Council, LLC Installed Capacity Subcommittee, Technical Study Report, *New York Control Area Installed Capacity Requirement For the Period May 2024 to April 2025* (December 8, 2023), https://www.nysrc.org/wp-content/uploads/2023/12/4.1.1-2024-25-IRM-Study-Report-and-Appendices-Attachment-4.1.1-compressed.pdf.

FIGURE 13: ATT CASE STUDIES AND THE *SEVEN BENEFITS*

Case Study #	Technology	*Benefits*						
		1	2	3	4	5	6	7
1: DNV-GL PJM Study	APFC	x		x				
2: DOE Lift-off Report	GETs	x						
3: SCE HPC and Transmission Towers	HPC	x						
4: NY DLR	DLR	x						
5: DOE GETs Report	DLR, APFC	x						
6: 2018 "Bomb Cyclone" and DLR	DLR (AAR)		x				x	
7: SPP Winter Storm Jupiter	TS		x				x	
8: SPP Winter Storm Elliot	TS		x				x	
9: HPC Design and History	HPC						x	
10: Brattle SPP GETs Study	DLR, TS, APFC			x	x			
11: RMI PJM GETs Study	DLR, TS, APFC			x				
12: Transmission Switching Studies	TS			x			x	x
13: GRE DLR	DLR			x				
14: ELIA DLR	DLR			x				
15: Hydro Quebec Conductors Comparison	HPC				x			
16: APFC 2015	APFC					x		
17: EPM and AFC	APFC					x		
18: Transmission Switching Study	TS					x		
19: PJM Winter Storm Elliot	DLR						x	
20: Nevada Energy HPC	HPC						x	
21: Oklahoma Gas and Electric HPC	HPC						x	
22: California Wildfire and HPC	HPC						x	
23: Canada Icing and HPC	HPC						x	
24: Southeastern US and HPC	HPC						x	
25: New York Phase Angle Regulators	APFC, TS							x

Several observations can be made from the ATT case summaries summarized in Figures 13 and 14. These include:

1. ATTs can provide multiple *Benefits*.

Notably, as shown in Figure 13, ATTs can provide all *Seven Benefits*. Transmission providers should thus explore the full capabilities and related *Benefits* of these technologies – which, as the vintage of some of the case study examples indicates, are mature and proven, demonstrated through multi-year deployments – as part of their solution-selection process.

ATTs providing multiple *Benefits* indicates the need for a cross-*Benefit* evaluation – e.g., how many of the *Seven Benefits* can a given ATT (or any potential transmission solution) provide -- because a solution that may not be the best under any one of the *Seven Benefits* may provide the highest benefit when multiple *Benefits* are looked at. A holistic evaluation method (rather than comparing solutions on *Benefit* by *Benefit* individually) aligns with the observations from *Benefit 4* that there could be cases where transmission losses increase because the solution is allowing lower cost generation located in remote locations to provide various other benefits, which outweigh the cost of increased transmission losses.

2. Some *Benefits* are easier to measure in monetary terms.

Monetizable *Benefits* are easier to incorporate in benefit-cost analyses and can be grouped into those that are investment-related or operations-related.

Benefits 1, 2, and *7* are the former and reduce investment needs.

Benefit 3, 4, and *5* are rather operational and can have immediate impacts, such as lowering the end consumers' utility bills. It should be noted that many traditional transmission

FIGURE 14: ATT CASE STUDIES AND THREE CORE CHARACTERISTICS

Case Study #	Technology	Characteristics		
		Installed faster at a lower cost	Complementary	Portability and Reversibility
1: DNV-GL PJM Study	APFC	x	x	
2: DOE Lift-off Report	GETs	x	x	x
3: SCE HPC and Transmission Towers	HPC	x	x	
4: NY DLR	DLR	x	x	x
5: DOE GETs Report	DLR, APFC	x	x	x
6: 2018 "Bomb Cyclone" and DLR	DLR (AAR)	x	x	x
7: SPP Winter Storm Jupiter	TS	x	x	x
8: SPP Winter Storm Elliot	TS	x	x	x
9: HPC Design and History	HPC		x	
10: Brattle SPP GETs Study	DLR, TS, APFC	x	x	x
11: RMI PJM GETs Study	DLR, TS, APFC	x	x	x
12: Transmission Switching Studies	TS	x	x	x
13: GRE DLR	DLR	x	x	x
14: ELIA DLR	DLR	x	x	x
15: Hydro Quebec Conductors Comparison	HPC		x	
16: APFC 2015	APFC	x	x	x
17: EPM and AFC	APFC	x	x	x
18: Transmission Switching Study	TS	x	x	x
19: PJM Winter Storm Elliot	DLR	x	x	x
20: Nevada Energy HPC	HPC		x	
21: Oklahoma Gas and Electric HPC	HPC		x	
22: California Wildfire and HPC	HPC		x	
23: Canada Icing and HPC	HPC		x	
24: Southeastern US and HPC	HPC		x	
25: New York Phase Angle Regulators	APFC, TS	x	x	x

solutions rarely provided active means to contribute to operational flexibility.[67] Also, while investment needs can be analyzed over longer periods, such as the 20-year planning period required by Order 1920, operational *Benefits* should be analyzed over shorter timeframes, such as a year (or even less for *Benefit 5*.)

Benefit 6 will be harder to measure in monetary terms because it could involve both investments (recovery of damaged equipment) and operations (avoided outages), and further is akin to an insurance – the value may not be recognized until a severe event happens.[68]

While monetizable *Benefits* should be assessed for all potential transmission solutions, lower-cost solutions – including ATTs – should be prioritized in the selection process. To pre-screen solutions and their likelihood of producing certain monetizable *Benefits*, transmission providers could develop an initial screening threshold (such as the normalized capacity cost savings in $X/kW units for *Benefit 7*) by analyzing past transmission projects together with wholesale energy market data (where such data exists) ahead of time.[69] This will likely speed up the selection process by eliminating higher-cost solutions for further consideration at an earlier stage before heavy modeling efforts are needed.

67 Exceptions include phase shifters, flexible alternative current transmission systems (FACTS) devices, GETs, and operational schemes, such as Remedial Action Schemes. The alternative is to rely on generation redispatch.

68 Even under extreme weather events or unexpected system conditions, evaluation of *Benefit 6* requires a comparison against a "what-if" case (e.g., what would have happened if the investment was not made), complicating the analyses needs.

69 Historical market data can also be used for calibrating the screening threshold.

3. Some *Benefits* are temporal in nature.

Certain *Benefits* – such as *Benefits 5* and *6* – do not represent expected system conditions and are instead temporal in nature. Assessing these temporal *Benefits* requires evaluation methodologies that look at (1) shorter timeframes than the traditional years-long evaluation timeframe and (2) alternative system conditions rather than the expected system conditions that are typically analyzed.

Similar to the operations-related *Benefits* discussed above (*Benefits 3*, *4*, and *5*), many of the solutions that provide temporal *Benefits* will likely be operational solutions (e.g., GETs, phase shifters, FACTS devices). The exception may be HPCs that provide *Benefit 6* because of their underlying design.

Evaluating these *Benefits* (*Benefits 3*, *4*, *5*, and *6*) will require analyses over various timelines. As discussed later in Section III: Current Planning Processes and ATTs, transmission planning today is structured around deterministic views for select future snapshots and does not necessarily analyze temporal system conditions, suggesting current analyses may not adequately capture these temporal *Benefits*. They also will likely not capture the benefits of certain GETs, such as DLR or Transmission Switching, as the deterministic analyses assuming a steady system condition may not recognize the use for these alternative technology options.

These observations highlight the changes transmission providers need to consider in evolving their planning process as part of the compliance filing. First, transmission providers need to develop new analytical methodologies and criteria to address shorter timeframe issues, including temporal system conditions. This will likely entail advancing the current production simulation analyses transmission providers conduct as part of their planning processes today. These simulations, performed over 8,760 hours a year, typically analyze the future grid under static (i.e., expected) system conditions. Alternative scenarios that represent temporal situations will be needed.

Second, associated with the new temporal scenarios to analyze, transmission providers will need to develop methodologies on how to consider benefits (and costs) over varying timelines. For example, evaluating a potential solution could require analyses over multiple timelines to capture the *Benefits* and associated trade-offs among *Benefits* (a solution could impact several *Benefits*) over different timelines. When considering ATTs, which can be installed faster than traditional solutions (see Figure 14 above), transmission providers not only need to recognize the benefits of speediness, but may also need to compare a solution that could potentially avoid a larger investment farther in the future with a solution that avoids an existing issue immediately with a smaller investment.[70]

The next section discusses the current process and outlines other potential barriers transmission providers need to address.

70 An example is comparing the benefits of avoided future investments of *Benefit 1* by developing a new line against the benefits of reduced production costs of *Benefit 3* that could start today by adding GETs to reduce transmission congestion.

III. Current Planning Processes and ATTs

As the case studies introduced in Section II.A: ATTs and *Seven Benefits* demonstrate, ATTs can provide all *Seven Benefits* laid out in Order 1920. These case studies show that GETs and HPCs should be incorporated into transmission planning as Order 1920 requires, although this will require some modification to the current planning approach.

Despite these benefits, ATTs have not been adopted and deployed on a wider scale, particularly for planning purposes. A review of the current (i.e., pre-Order 1920) transmission planning process identifies four barriers that exist today to fully integrating ATTs into the planning process.

A. Barriers for ATTs

Many of the current (i.e., pre-Order 1920) planning processes used by transmission providers today are built on a deterministic framework that identifies transmission needs driven primarily by reliability requirements with some secondary consideration of public policy and economics drivers. These processes evaluate transmission solutions for a given planning time horizon, such as 10 years, and may contain interim target years. Diverse scenarios are often developed to reflect uncertainties in forecasting future system conditions, which allows for a transmission expansion plan that is sufficiently flexible to meet a variety of needs.

For reliability assessments, planners develop power flow models representing key system conditions during the target study years (such as summer peak and winter peak with high loads and shoulder seasons with low load and high renewables). Planners then simulate the system under each static snapshot. The simulations examine if the system meets the reliability standards and identify any transmission needs to maintain reliability, such as to remedy for thermal overloading, voltage violations, stability, and other issues observed from the analyses.

For economic assessments, most, but not all, regions run hourly (i.e., 8,760 hours per year) production simulations and identify transmission constraints with significant congestion costs. Planners also use these models to identify public policy drivers and other operational needs for transmission. Key input assumptions for the models include expected resources, load forecasts, long-term firm transmission service usage levels, and transmission network (and topology).

Upon completing the analyses, planners solicit transmission solutions to address the needs identified, evaluate each potential solution, and make selections, often with stakeholder input. Potential solutions considered are typically traditional wires-based solutions, such as building new lines or upgrading existing ones. Non-wires technologies, such as FACTS, may also be considered as potential solutions in the evaluation process. However, not all technologies, including some of the ATTs discussed in Order 1920 or Order 2023, are recognized in this process.

Appendix B uses SPP as an example to illustrate the typical pre-Order 1920 planning process.

Reviewing the traditional transmission planning process reveals four types of barriers to incorporating ATTs:

- Barrier 1: Lack of Recognition (of ATTs)
- Barrier 2: Misaligned Incentives
- Barrier 3: Legacy Planning (using static and deterministic approaches)
- Barrier 4: Execution Limitations

Each of these four barriers is discussed below.

Barrier 1: Lack of Recognition (of ATTs). One of the deployment challenges observed by GETs and HPC vendors (not limited to the technologies discussed in Orders 1920 and 2023) is the lack of recognition by transmission providers. One reason for this barrier is the slow and conservative pace of the industry, which sees embracing innovative approaches to be at odds with maintaining reliability – and therefore fails to pursue such opportunities – as well as the often incorrect view of these technologies as still immature, if not unknown or unfamiliar.

Another contributing factor is that there is no common definition of ATTs. For example, FERC Order 2023, which stemmed from the same ANOPR as Order 1920, requires transmission providers to consider the following eight technologies as potential solutions to reduce the need for network upgrades during the generator interconnection study process: Static Synchronous Compensators; Static VAR Compensators; APFC devices; Transmission Switching; Synchronous Condensers; Voltage Source Converters; Advanced Conductors; and Tower Lifting. Only APFC devices, Transmission Switching, and Advanced Conductors are common between Orders 2023 and 1920.

Similarly, the US DOE Liftoff Report defines GETs as DLR, APFC, Topology Optimization (including Transmission Switching), Virtual Power Plants (VPPs), Energy Storage (as a T&D asset), and Advanced Flexible Transformers. DOE lists Advanced Conductors and Point-to-point High Voltage Direct Current (HVDC) as advanced transmission technologies, distinguishing them from GETs.

The industry's understanding of what constitutes HPCs varies as well. Idaho National Laboratory's (INL's) recent survey of 44 utilities shows that over 70% of these utilities responded that they have deployed advanced conductors.[71] INL estimates that there are still nearly 120,000 miles of existing transmission lines that would benefit from reconductoring with advanced conductors. INL suggests this gap between the survey results and the actual level of advanced conductor deployment occurs partially because INL's rather liberal definition of advanced transmission conductors – "technologies that can be used to increase the pace of transmission capacity growth, at a lower cost and with less impact to communities than traditional conductors" – can be interpreted as including conventional steel core designs.

By comparison, the Working for Advanced Transmission Technologies (WATT) Coalition and Advancing Modern Powerlines (AMP) Coalition define HPCs as those with carbon or composite cores or superconducting capabilities.[72] DOE's Liftoff Report defines advanced conductors as those that increase line capacity by more than 50% (at a similar weight per foot) and use composite cores instead of traditional steel cores.

Further complicating this barrier is that many different technologies can be included within one technology category. For example, Order 1920 recognizes six different HPCs. There are differences among DLR technologies as well – some can directly measure sag, while others may estimate line sag through measurements of other external factors (e.g., ambient temperature, wire temperature, and wind speed) that contribute to line sag, which by themselves can also be measured directly, or calculated from other measurements (e.g., different frequencies of line vibration). As newer technologies are developed and become available, technologies not currently recognized as viable may well be qualified for use on the grid in the near future.

71 US Department of Energy, *Advanced Conductor Scan Report: Summary* (2024), https://www.energy.gov/sites/default/files/2024-02/Advanced%20Conductor%20Scan%20Report%20Summary_optimized.pdf.

72 WATT Coalition and AMP Coalition, *Unlocking the Grid with Advanced Transmission Technologies*, WATT-and-AMP-Unlocking-the-Grid-with-Advanced-Transmission-Technologies.pdf.

Even when the transmission provider is familiar with a given technology, they could view it as unsuitable for planning purposes. For example, DLR and Transmission Switching are often viewed by transmission providers as operational tools rather than integral components of long-term transmission planning. One key concern with these technologies is that they often provide "non-firm" transmission capacity based on dynamic and real-time conditions. These may be seen as less predictable than the firm transmission that is based on static fixed values. The non-static nature of transmission lines with these technologies deployed may require a different approach that may be new to grid planners and require a period of adjustment. Some may be concerned that DLR could lead to overly optimistic line ratings while not fully acknowledging the disadvantage of conservative static line ratings, which is analogous to driving on a highway at the lower speed limit adopted for snowy days when the weather is clear and there is no snow or ice on the roads.

The recognition barrier goes beyond the individuals involved in planning and can be more of a systematic issue, as is the case of DLR for SPP. SPP's current transmission planning tariff does not recognize some technologies as potential solutions in transmission planning.[73] A tariff revision that clearly requires GETs and HPC to be fully considered when identifying transmission solutions is needed to remove this barrier, as should result when Order 1920 is fully implemented.

Barrier 2: Incentive Misalignments. The second barrier is the misaligned incentives for the transmission providers. First, the conservative industry culture that penalizes failure more than rewarding success does not help deploy newer technologies. The current conservative planning process focused on deterministic "worst-case" scenarios reinforces a reluctance to embrace innovative solutions that provide greater efficiency rather than planning for such worst cases.[74]

Moreover, for the transmission owners, the cost-based regulatory construct that provides higher returns (in absolute values) on capital-intensive transmission projects than lower-cost technologies can contribute to this hesitancy. The perception of ATTs as "operational" (partially due to the first barrier: Lack of Recognition) also provides a disincentive because, under the cost-based regulatory construct, capital investments are a source of revenue (or cash coming in) through a return on the investment and operational costs are expenses (or cash going out).

Third, many costs – such as higher energy costs due to transmission congestion or higher investment costs – are passed through to customers with little direct impact that can be felt by the transmission providers (both owners and operators). Transmission providers may not prioritize the avoidance of these costs.

Aligning incentives will be critical in enabling the widespread use of ATTs in transmission planning.[75]

Barrier 3: Legacy Planning (using static and deterministic approaches). The current planning processes are not dynamic, nor are they flexible. As discussed earlier, study time horizons are typically fixed with specified target years, and the analyses use static and deterministic methods. For example, power flow studies that are central to reliability assessments are structured around a set of static "snapshots" of grid conditions for future target study years. This static approach is not adequate to fully capture the benefits that are associated with finer granularities of time (including transitionary times), such as those provided by GETs and HPCs, as discussed in the previous section.

Further, the current static approach is ill-fitted for evaluating renewable energy sources' excess generation or stress on transmission lines within shorter timeframes. Similarly, it will not adequately capture the increasingly complex and uncertain nature of load-driven by factors such as EV adoption, changing heating/cooling patterns, and distributed energy resources (DERs), which all would require a much more dynamic study approach.

73 See Appendix B: Current Transmission Planning Processes.

74 US Department of Energy, *Grid-Enhancing Technologies*.

75 MIT Center for Energy and Environmental Policy Research, *A Roadmap for Advanced Transmission Technology Adoption* (September 2024), 6, https://ceepr.mit.edu/wp-content/uploads/2024/03/MIT-CEEPR-RC-2024-06.pdf.

Moreover, current transmission planning typically assumes a "one-size-fits-all" approach that prioritizes traditional infrastructure upgrades, such as the construction of new transmission lines or substations. Such projects may not be the most effective or timely solutions for addressing near-term transmission needs that continue to evolve before large transmission projects to meet longer-term needs can be put in place. Overall, this lack of flexibility in the planning process limits the ability of transmission providers to optimize their systems. Taking full advantage of ATTs could provide cost-effective, scalable solutions for the grid.

The rather conformist approach of the traditional transmission planning process does not address uncertainty well. As key inputs for transmission planning today, both load and resources are expected to see exponential growth in the future, but their forecasts are highly uncertain.[76] While the industry has started to recognize uncertainties in resource planning, such as through the introduction of effective load-carrying capability (ELCC) as a measure to calculate capacity accreditation, the transmission planning process remains largely deterministic. This makes it harder to "right-size" transmission solutions and balance cost and future needs, a concern that Order 1920 is aimed at addressing.

Barrier 4: Execution Limitation. This last barrier can be observed in two ways. First, the traditional planning tools – such as power flow and production cost models – for reliability and economic assessments that are used in the static and deterministic approach may appear insufficient to planners who wish to perform a more dynamic analysis.[77] For example, the temporal and dynamic nature of some of the ATTs may make them difficult to integrate into the current reliability analysis and economic planning models.[78,79] In addition, planners often lack standardized data and methodologies to perform advanced analyses for various ATTs, including HPCs.[80]

ISO-NE stated they are encountering difficulties modeling the capabilities and impacts of newer technologies such as APFC and topology control (i.e., Transmission Switching) in forward-looking tools and, more critically, in the Energy Management System (EMS) as the advancements in transmission technologies outpace the industry's ability to accurately simulate and analyze them. The ISO has been manually implementing topology changes (i.e., Transmission Switching) to improve system performance for a very long time because it takes time to evaluate software that automatically identifies topology control solutions for thermal constraints.[81] Addressing these modeling challenges is an essential step to fully integrating some of the ATTs into the planning process.

Second, the industry is facing a lack of skilled power engineers. Many engineers who would conduct transmission planning are overwhelmed by the sheer volume of generator interconnection queues that strain their capacities. Assessing the cost-effectiveness and feasibility of ATTs requires sophisticated techno-economic modeling, which further tightens the resource pool.

Order 1920, by mandating transmission provider consideration of ATTs, helps alleviate Barrier 1 (Lack of Recognition). Barrier 2 (Misaligned Incentives) and Barrier 3 (Legacy Planning) are rather more complex, intertwined, and will likely take some time to address, and may require legislative and regulatory policy changes. The need to enhance the analyses, as discussed in Section II.B: Observations and Recommendations, can exacerbate Barrier 3 (Legacy Planning). Barrier 4 (Execution Limitations) is commonly faced

76 GridLab, *Supporting Advanced Conductor Deployment: Barriers and Policy Solutions* (April 2024), 5, https://www.2035report.com/wp-content/uploads/2024/04/Supporting-Advanced-Conductor-Deployment-Barriers-and-Policy-Solutions.pdf.

77 US Department of Energy, *Grid-Enhancing Technologies*.

78 Idaho National Laboratory, *Assessing the Value of Grid Enhancing Technologies: Modeling, Analysis, and Business Justification* (June 2023), https://www.esig.energy/download/assessing-the-value-of-grid-enhancing-technologies-modeling-analysis-and-business-justification/?wpdmdl=10261&refresh=647f2630744721686054448.

79 Idaho National Laboratory, *Grid Enhancing Technologies in Long-Term Transmission Planning* (July 2023), https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_66797.pdf.

80 One solution may be to have regional technical application guides that ensure ATTs are integrated into models and draw on lessons learned from other utilities. However, this also requires building up experience.

81 Massachusetts Executive Office of Energy and Environmental Affairs, "Pop-Up Forum on Grid Enhancing Technologies – ISO New England Presentation" (July 2023), https://www.mass.gov/doc/ma-eoeea-pop-up-forum-on-grid-enhancing-technologies-iso-new-england-presentation/.

by many businesses and can be improved over time. The tools, data, and methods to evaluate the merits of ATTs will improve and evolve over time. The pursuit of perfection regarding these should not stifle decision-making, real progress, and wide-scale deployments of ATTs in planning.

Multiple states have developed and implemented policies aiming to address these barriers, which are provided in the appendix.

B. Transmission Provider Evolutions

Partially motivated by state and federal policies, together with the recognition of ATTs, some transmission providers have been developing frameworks to integrate ATTs.

The California ISO (CAISO) supports the appropriate application and deployment of GETs and HPC in its transmission planning process and has considered them on a case-by-case basis as potential alternatives. CAISO typically considers advanced conductors and power flow controllers as planning tools that provide an alternative to other capital expenditures. CAISO also considers DLR and Transmission Switching to provide operational benefits through additional capacity to meet economic or emergency needs.

ISO-NE also recognizes the importance of including GETs and HPCs in its transmission planning. For example, ISO-NE's 2050 Transmission Study explored advanced conductor technologies that could leverage existing infrastructure while providing higher capacity and reducing energy losses.

ISO-NE notes that further inclusion of GETs into transmission planning is a priority driven by the New England Power Pool (NEPOOL, which is the ISO-NE governing body) and the states as represented by the New England States Committee on Electricity (NESCOE). ISO-NE addresses this need in two parts – focusing on "when to consider GETs" and "how to apply GETs" – and is developing revisions to its Open Access Transmission Tariff (OATT) for when transmission planning assessments must consider GETs as part of ISO-NE's compliance with for Order 1920. The consideration of GETs in interconnection assessments has already been incorporated in ISO-NE's OATT and was a part of their Order 2023 compliance filing (currently pending at FERC).[82] ISO-NE expects that stakeholder discussions will continue at their Planning Advisory Committee in 2025 to establish guidelines for the applicability of these technologies in assessments (i.e., "how to apply GETs"). These discussions will commence with a review of how GETs are currently considered in assessments, defining a problem state that the GETs are intended to solve, determining the benefits of GETs over other technologies, and identifying limitations, risks, and costs.

Similarly, SPP is developing its Strategic Initiative Requests 723 (SIR723), which determines and prepares for the best use-cases for GETs within SPP, both from an operational and planning perspective, to comply with Order 1920.[83] SPP views these ATTs as a potential avenue for mitigating economic congestion in the short term while more permanent solutions are being constructed. SIR723 will define and approach each GET on an individual basis, both from a policy and a study perspective, to determine what (if any) policy changes need to be put in place to facilitate the usage of GETs.

SIR723 is expected to address:

- Individual study and operational practices that will best represent each GET's performances in both operational and planning studies.
- Study process language to facilitate the potential combination of GET devices with traditional transmission solutions to capture both short and long-term benefits.
- How cost allocation might work given different life spans or needs for technology.

MISO's Near-Term Congestion Study, which was part of MISO's 2024 Transmission Expansion Plan (MTEP), is another example of how an ISO/RTO is considering ATTs (in this case, Transmission

82 ISO New England, "Order No. 2023 – Improvements to Generator Interconnection Procedures and Agreements"(April 12, 2024), slide 30, https://www.iso-ne.com/static-assets/documents/100010/2024_04_12_tc_order2023a_adjustments_and_redline_updates_presentation.pdf.

83 Southwest Power Pool, "09 – SIR723 Grid Enhancing Technologies (GETS) for use in Transmission Planning posted in Joint ESWG-TWG Meeting Materials 2024030 folder," accessed December 31, 2024, on the SPP website.

Switching).[84] MISO solicited input from stakeholders on potential alternative solutions to address projected congestion as part of its planning process. How MISO will share the stakeholder-suggested GETs solutions with the relevant transmission owners and how proposed Transmission Switching should be handled for outages that are more than a year in the future are both still unclear. Regardless, MISO has successfully reduced congestion for some constraints using Transmission Switching, and others appear to have the potential for further congestion cost savings.

MISO has expressed interest in considering Transmission Switching solutions in the context of Long-Range Transmission Planning Tranche 1 construction outages. However, it is difficult to reconcile this interest and reported success with MISO's limitations of Transmission Switching requests.[85] MISO's implementation of a process to evaluate Transmission Switching requests from market participants is a significant first step towards leveraging ATTs for congestion management in that it brings structure to their use compared to the more usual ad hoc treatment in the industry. Various stakeholders are pushing for process improvements, including a more systematic, transparent effort to consider alternative solutions to manage congestion during planned outages going forward, including those identified and proposed by MISO itself.

While these examples are encouraging, thus far the practices have not yet led to widespread deployments of ATTs at the speed that end customers and RSEs may like to see. It could simply be that some of these changes have not been in place long enough to fully know the effects. It could also indicate that transmission providers may not be recognizing the full range of benefits ATTs can provide.

84 Midcontinent Independent System Operator (MISO), "MTEP24 Congestion Study" (November 13, 2024), slide 14, https://cdn.misoenergy.org/20241113%20PAC%20Item%2006a%20Near-Term%20Congestion%20Study660238.pdf.

85 MISO estimates $21 million in savings from five reconfigurations in 2024. See MISO, "Reconfiguration for Congestion Cost Update" (August 29, 2024), available at: https://cdn.misoenergy.org/20240829%20RSC%20Item%2005%20Reconfiguration%20for%20Congestion%20Cost%20Update644561.pdf.

IV. Considerations for Relevant State Entities

Order 1920 requires transmission providers to analyze the *Seven Benefits* (as discussed in Section II.A: ATTs and *Seven Benefits*) for potential solutions as part of the transmission selection process and further allows consideration of additional benefits. The Order also requires that the processes for selecting transmission solutions must account for both benefits and costs without prescribing methodological details or how the different options should be weighed against each other. For example, the Commission explains that transmission providers may use benefit-cost ratios, measures of net benefits, or other methods, including a least-regrets approach that prioritizes facilities that are net beneficial in more than one scenario.[86]

Order 1920-A ensures the integral role of RSEs, which includes state regulators, in the transmission planning process. It requires transmission providers to seek input from the RSEs on the specifics of the evaluation methodology and selection criteria used for the long-term planning processes. As part of this process, state regulators may recognize the need to address uncertainty to optimize costs over the longer term. Addressing uncertainties can be for costs and schedules of potential transmission solutions, or the flexibility to deal with unknowns of the future world as it reveals itself. This flexibility can be incorporated into the potential transmission solution, or in the selection process by recognizing the value of such optionality.

A. Benefit-to-Cost Ratio and Cost Certainties

State regulators primary interest is protecting consumers through mitigating unnecessary rate increases. To ensure that costs are optimized over the long run, states could specify additional cost-related selection criteria to be considered alongside the previously discussed *Seven Benefits*. For example, RSEs may find selection criteria that include some benefit-to-cost ratio preferable to those that only use the highest net benefit approach as a way to keep costs under control. RSEs may also find selection criteria that are associated with certainty – such as for costs and schedules – to be beneficial because the price of cost and scheduled overruns are typically paid by the consumers rather than the transmission providers.

The recent experience of PPL (formerly known as Pennsylvania Power and Light) installing DLR systems vividly demonstrates its higher benefit-to-cost ratio together with the additional certainty-related benefits.

PPL installed DLR systems to relieve congestion on their Harwood to Susquehanna 230 kV path. The DLR program went live in October 2022 and provided forecasted line capabilities ratings to better inform the Day-Ahead and Real-Time PJM markets. PPL reports that their DLR deployments have operated successfully since deployment and that DLR eliminated congestion (which was $12 million in summer 2022) entirely on the Harwood to

86 See Order 1920 at pages 966 and 967.

FIGURE 15: COMPARISON OF POTENTIAL SOLUTIONS FOR THE HARWOOD TO SUSQUEHANNA 230 KV PATH

	Reconductor	Rebuild	Dynamic Line Rating
Time to Implement	2-3 Years	3-5 Years	~1 Year
Downtime	Extended Outages	Extended Outages	No Outages
Cost	$0.5 Million per mile	$2-3 Million per mile	<$50 Thousand per mile*
Est. Capacity Benefit	+34%	+106%	+10-30%

*<$1 Million total cost on 20-mile line & longers lines are cheaper

Susquehanna 230 kV path. PPL also installed DLR on the Juniata to Cumberland 230 kV path and reduced congestion from ~$66 million to ~$1.6 million.[87]

Figure 15 shows three potential solutions PPL considered for the Harwood to Susquehanna 230 kV path.[88]

The figure shows an investment cost of $1 million for installing DLR on the Harwood to Susquehanna 230 kV path. This cost, together with the $12 million congestion reduction benefits discussed above, indicates that the payback period is better measured in months or perhaps weeks rather than years.[89] The short payback period (or high benefit-to-cost ratio) means the benefits will accrue immediately and that there should be minimal concerns about the investment becoming stranded. PPL has since reported that they plan to install DLR on five more lines.

Cost certainty may be equally as important to RSEs as a high benefit-cost ratio. The costs and associated uncertainty of GETs (and ATTs in general) are significantly smaller than those of the traditional wires-based solutions. As Figure 15 shows, potential solutions PPL considered alongside DLR included reconductoring existing lines (with an estimated cost of $0.5 million per line-mile) and enhancing the path to double-circuit lines (with an estimated cost of $2 to $3 million per line-mile).[90] These estimates show that

87 WATT Coalition, "Press release: new RMI study, comments in FERC DLR docket from PJM, PPL Electric Utilities," (February 15, 2024), https://watt-transmission.org/grid-enhancing-technologies-could-unlock-more-reliable-affordable-clean-energy-in-pjm/ and Federal Energy Regulatory Commission, *Implementation of Dynamic Line Ratings* (Docket No. AD22-5), "Motion for Leave to Comment and First Supplemental Comments of PPL Electric Utilities" (February 9, 2024), https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20240209-5161.

88 Eric Rosenberger, PPL Electric Utilities, "Dynamic Line Ratings" (October 2024), https://www.energypa.org/wp-content/uploads/2024/10/Dynamic-Line-Ratings-E-Rosenberger.pdf.

89 Assuming a cost of $1 million for the DLR for the Harwood to Susquehanna 230 kV path and a $12 million annual reduction in congestion indicates a payback period of a month. $12 million of congestion was for the summer so the annual congestion may have been greater. Assuming similar magnitude of costs for the Juniata to Cumberland 230 kV path and $64 million of savings indicate the payback period can be measured in weeks.

90 AES installed DLR over five lines in Indiana and Ohio and indicates similar costs of $45,000 per mile for DLR (including 20 years of software services) and $590,000 per mile for reconductoring. AES also estimates DLR installation (from planning) to take less than a year (nine months) while reconductoring will require two years, with outages of approximately one week per mile. See AES Corporation and LineVision, *Lessons from first deployment of Dynamic Line Ratings* (April 2024), https://www.aes.com/sites/aes.com/files/2024-04/AES-LineVision-Case-Study-2024.pdf.

not only was DLR, installed along the whole path for less than $1 million, the low-cost option, but also the range of the estimated unit cost (i.e., per-mile cost) for a double-circuit solution was larger than the estimated total cost of DLR. If these estimates are valid and with comparable accuracies, the DLR solution shows a much higher level of cost certainty.

The benefits the PPL example highlights are not limited to the two cost-related benefits. There are also scheduling benefits (including avoiding outages), which could further reduce cost uncertainties. For example, Figure 15 shows that the two traditional wires-based solutions considered (reconductoring and double-circuit) would have required extended outages.[91] Outages could lead to more congestion and, even if temporal, would add to consumer costs.

Figure 15 highlights another characteristic of ATTs – that they can be installed in a shorter time. The figure suggests reconductoring and double-circuit solutions would require multiple years to implement, with time estimate ranges for installation surpassing the total time estimated for installing the ATT solution (i.e., DLR).

All of these observations indicate that GETs provide more certainty in both costs and scheduling than traditional wires-based solutions. Similarly, HPCs provide schedule certainty because of their complementary nature to existing equipment.

HPC applications today largely reconduct existing lines that reuse existing towers and rights-of-way.[92] Reconductoring using in-kind wires may also be an option; however, in the PPL example (as shown in Figure 15), the capacity benefit of reconductoring using in-kind wires is 34%, while reconductoring with HPCs can bolster the capacity by 50% to 100% or even more. If the identified need is for a much larger transfer capacity, HPCs will provide more schedule certainty than expanding the path through a traditional wires-based solution, such as by enhancing to double-circuits or using higher-voltage conductors. These traditional wires-based solutions may require new towers and wider rights-of-ways, which add to the cost and schedule, as well as associated uncertainties.[93]

Figure 16 provides a summary by DOE that compares the costs and benefits of various transmission technologies along with their estimated payback periods, which is a representation of the benefit-to-cost ratio. It shows how the benefit-to-cost ratios are higher (and payback periods are shorter) for GETs and confirms that observations from the PPL example above are not a special case.

A solution that includes lower-cost options as part of its portfolio will likely result in a higher benefit-to-cost ratio.[94] The benefits would expand beyond the solution itself. For example, GETs can further complement the larger permanent solution – whether it is traditional wires-based or HPC-based – by enabling higher operational efficiencies, including increasing utilization of the existing assets or by providing situational awareness (such as through DLRs and associated sensors). Studies and actual deployments have shown that ATTs will increase the utilization of the existing system. So from a benefit-to-cost ratio perspective, including ATTs in the solution portfolio should be an easy decision. Adding to this is that costs for ATTs (both GETs and HPCs) have been decreasing, while those for traditional wires-based solutions have been rising.[95]

91 Reconductoring can be done "live" (i.e., without de-energizing the conductor) and thereby reduce or eliminate the need for outages.

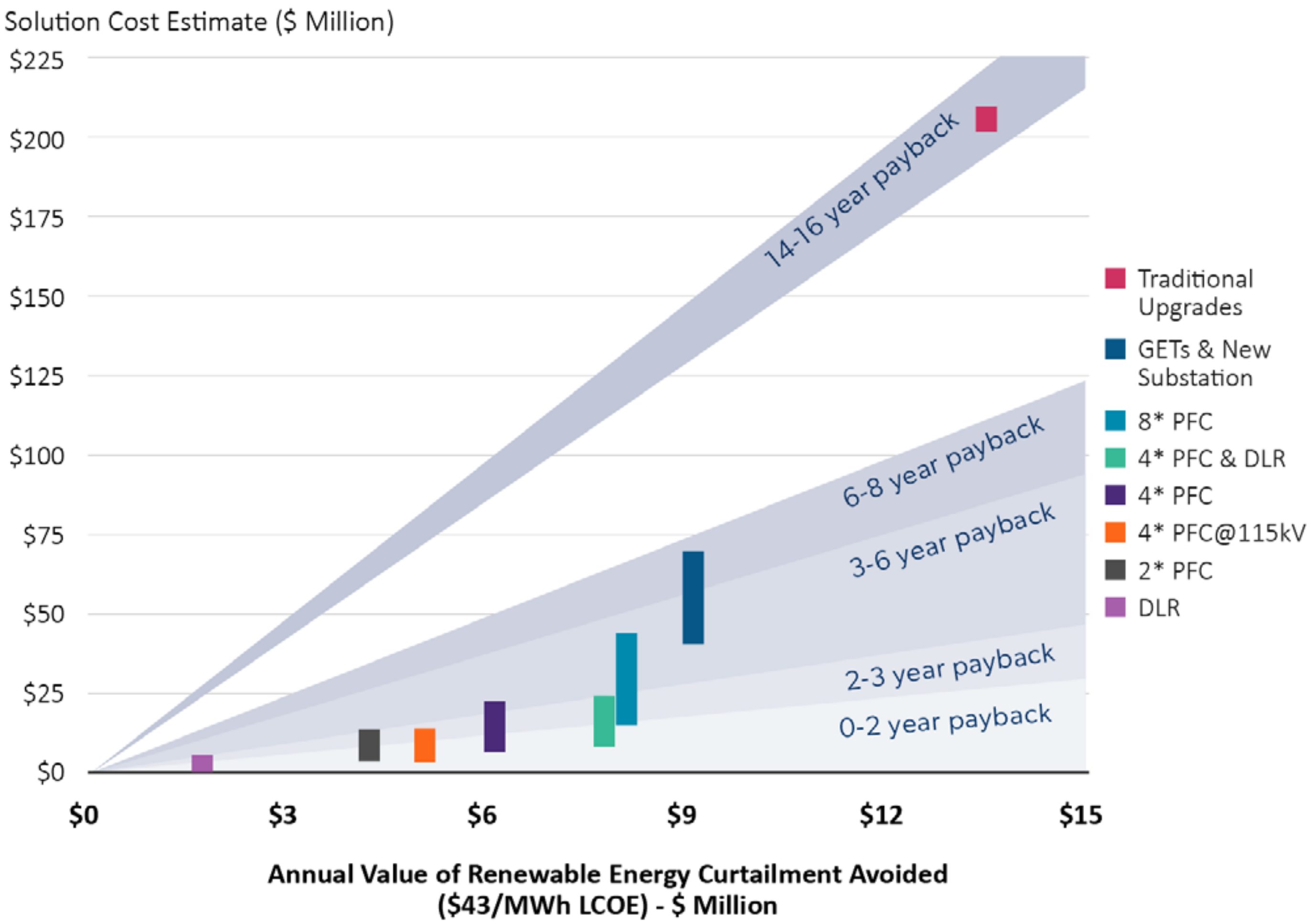
92 Like conventional conductors, HPCs can be reconductored "live" without outages. American Electric Power reconductored its Lower Rio Grande Valley (LRGV) path using CTC Global's HPC in November 2015. See Quanta Energized Services, "Record Energized Reconductor Project Brings Reliable Power to South Texas" (Spring 2016), https://www.quantaenergized.com/wp-content/uploads/2015/05/EEI-Energy-Biz_pages.pdf.

93 Wider rights-of-ways or taller towers may require additional siting and permits, which could increase costs and schedule uncertainties (i.e., delays).

94 For example, a DOE report estimates for a specific region of New York State, DLR cost of approximately $2 million, APFC cost of ranging between $7 million and $28 million (depending on the number of devices deployed), and traditional transmission upgrades at $205.5 million. See US Department of Energy, *Grid-Enhancing Technologies*.

95 MIT estimates installing DLRs to cost about one-tenth of upgrading to HPCs and just one-twentieth of constructing new transmission lines using conventional conductors. See MIT Center for Energy and Environmental Policy Research, *A Roadmap for Advanced Transmission Technology Adoption*.

FIGURE 16: COST AND BENEFITS COMPARISON



B. Optionality

Another benefit RSEs may want to consider is those associated with flexibility and optionality, which help transmission providers address longer-term uncertainties (e.g., realization of future loads as projected) – and FERC's request that providers "right-size" investments.

Section I.C: Overview of GETs and HPC introduced three key characteristics of ATTs: (1) Lower cost and faster installation, (2) Complementarity to existing equipment, and 3) Portability and reversibility. The PPL example discussed in Section IV.A: Benefit-to-Cost Ratio and Cost Certainties largely reviewed them in light of mitigating cost increases for the immediate time period.

The benefits associated with ATTs' characteristics – their complementarity to existing equipment and their portability and reversibility – further provide benefits that can address longer-term uncertainties. This comes in two distinct ways.

First, as the PPL case study demonstrated, the low-cost characteristics together with the reversibility of GETs make them a low-regrets option that are suitable for addressing temporal issues. One could choose to install GETs on an already congested path and reduce congestion immediately until a permanent wires-based solution is implemented, and then remove the GETs (see *Benefit 5* from Section II.A: ATTs and *Seven Benefits*). A transmission provider may consider installing DLRs – even on a temporal basis – together with newly built lines to measure the actual sag and transfer capability of the new lines. And if the permanent wires-based solution resulted in new congestion patterns that were not foreseen during planning, GETs could help alleviate that as well. These application of GETs illustrate how they can address unexpected situations, similar to how ATTs provide

Benefit 6 (Mitigation of extreme weather events and unexpected system conditions), immediately and without negative financial consequences (e.g., stranded costs).

ATTs provide further benefits that will help with providing flexibility for planning. For example, installing GETs today as a bridging solution, can buy the transmission provider some time before deciding on the optimal solution. This could provide a wider range of options to choose from and also reduce schedule and cost pressures as the additional time changes the urgency and the elasticity of the needs. This extra time can reduce the risk of the larger wires-based investments by allowing the transmission provider to observe and assess how the landscape evolves – for example, how the projected load materializes -- before making final investment decisions. Such evaluation requires assessing the value of time and cost of uncertainty, which has not been well addressed in today's deterministic assessments.

In addition, optionality and expandability as tools for "right-sizing" with lower regrets should be considered in planning. For example, using more flexible arrangements on a new substation, such as a ring bus or double bus designs to provide more options for Transmission Switching applications, is likely worth the additional cost. Evidence to date suggests savings from Transmission Switching could easily recoup such costs; however, if such facts are not well understood, the decision made by the transmission provider or the regulator may not be as rational. Other examples of providing such optionality may include considering a breaker and half design for replacing a ring bus configuration in an aging substation and gaining operating flexibility or reconductoring using HPCs rather than conventional cables to provide headroom in anticipation of a future usage increase.

C. Considerations Beyond Benefits

The examples discussed in the previous two sections highlight additional benefits that should be considered but are not well addressed in current planning processes, nor are they discussed clearly in Order 1920. There are factors beyond the benefits that RSEs should be aware of, as discussed in various sections of this report. This subsection consolidates them.

First, as discussed in Section II.B: Observations and Recommendations, the *Seven Benefits* and the characteristics of ATTs require the planning process to look at multiple timeframes within the planning horizon (e.g., 20 years). The desired timeframes may vary by technology and *Benefits* to analyze. This can be quite different from what transmission providers are used to today. How would a transmission provider compare the benefits of a solution that immediately addresses an ongoing issue today with another solution that can avoid a potential but much larger issue that may not occur for five years?

Second, the complementary characteristics of ATTs suggest selection approaches that directly compare individual solutions may not be adequate. For example, if the need is to increase the transfer capacity over a given path, the proper comparison of solutions may not be a traditional wires solution versus GETs (such as DLR) alone over a 20-year period.[96] Rather, the assessment should look at the performance of the traditional wires-based solution with and without GETs.

In this example, low-cost GETs will also help the larger traditional wires-based solution pass the benefit-cost ratio threshold if there were to be one (e.g., Order 1920 allows the use of a ratio no greater than 1.25).[97] This is because the cost of GETs is almost negligible when compared to that of the larger wires-based solution, while the benefits can be comparable, even though they may be temporal. In addition, GETs can increase the utilization of the rest of the system, including the newly added line(s). The complementarity can also allow the co-locating of

96 For example, SPP's evaluation of non-transmission solutions typically involves comparing them to new transmission infrastructure to solve ITP needs, not consideration of both. See 04-Grid Enhancing Technologies from SPP Economic Studies Working Group materials available at: https://spp.org/Documents/71824/Joint%20ESWG-TWG%20Meeting%20Materials%2020240626.zip

97 Transmission needs analyzed in various studies are typically based on economic models. The needs identified represent the transmission buildout that achieves the most cost-effective electricity system. Therefore, higher transmission costs will lead to lower buildouts as the optimal solution. If transmission costs are lower, the optimal solution will recommend more transmission. Since ATTs – GETs in particular – will generally reduce the cost of adding transmission, they will likely make transmission the more cost-effective solution, leading the economic models to suggest solutions with higher levels of transmission.

these technology options, as examples in Section II.A: ATTs and *Seven Benefits* illustrate.

Third, the *Seven Benefits* should not be compared on an isolated basis. The previously outlined case studies show that ATTs can provide multiple *Benefits*, requiring an evaluation methodology that looks across all benefits (including those outside the seven outlined in Order 1920) rather than on an individual benefit-by-benefit basis. Even if the scoring for an individual *Benefit* is not very high for a given solution, the collective sum of multiple *Benefits* may outweigh other solutions that score high in one *Benefit*.

These observations suggest that current transmission planning, which is largely done through a linearized, static, and deterministic approach (as discussed in Section III: Current Planning Processes and ATTs), should become much more granular, dynamic, and holistic, with the flexibility to adjust the selection process as needed. Recognizing and further incorporating such evolutions in transmission planning through the Order 1920 compliance filings requires overcoming the four barriers discussed in Section III, as well as the analyses challenges discussed in Section II.B: Observations and Recommendations. Doing so is a crucial step for transmission providers, both at the state and federal levels.

RSEs can work with transmission providers to ensure the planning process achieves the full benefits of ATTs through the following practices:

- ✓ Recognize that ATTs are proven technologies that transmission providers need to consider as they develop the solution selection process using the *Seven Benefits* outlined in Order 1920.
- ✓ Incorporate some means for cost-containment, such as a higher benefit-to-cost ratio (but not necessarily the lowest immediate cost).
- ✓ Consider benefits beyond the *Seven Benefits*, such as benefits associated with time and optionality (e.g., speediness to solve the underlying issue or providing flexibility in selection and schedule) and certainty (e.g., schedule and cost certainty).
- ✓ Use multiple timelines that may vary by scenarios or benefits being analyzed.
- ✓ Conduct a holistic evaluation, which may not always be based on a direct comparison of solutions for given criteria (such as scoring against just one of the *Seven Benefits* rather than all or comparing GETs alone to a traditional wires-based solution).

In addition, RSEs can help transmission providers think beyond the current status quo (and help break the four barriers).

For example, transmission providers may view ATTs – particularly GETs such as DLR and Transmission Switching – as operational tools that are not apt for long-term planning. This may have been true in the past when planning (not limited to transmission, but also for resources) was largely performed in a static and deterministic way. However, planning has been evolving and improving.

Take resource adequacy planning as an example. Resource adequacy traditionally focused on ensuring there is enough capacity available for peak load days. Today, this deterministic process has evolved to apply stochastic concepts such as ELCC to calculate capacity accreditation, particularly for renewable resources with intermittent outputs that depend on weather patterns. PJM has advanced further and now calculates ELCC of all resources by technology type on an hourly basis, which allows PJM to assess resource adequacy for all hours of the year. If the same evolution can be applied to transmission planning, DLRs (or AARs) with varying hourly line ratings can be incorporated into planning, just as renewable resources with varying hourly outputs have been accepted as a part of the resource planning process.

Similarly, Transmission Switching can be part of long-term transmission planning. If persistent Transmission Switching solutions are observed, this could be reflected in the appropriate planning power flow cases (e.g., seasonal cases or cases developed for sensitivity analyses; see Section III: Current Planning Processes and ATTs). Some such cases could be considered as the new baseline topology so that the associated Transmission Switching occurring would be the default. The application of a persistent Transmission Switching solution that permanently resolved the most expensive constraint in SPP in 2019 is one example.[98] Temporary Transmission Switching, which is usually thought of as an operational solution, also has planning applications and may be available to meet different planning scenarios required by Order 1920. The same concept can apply to other ATTs as well, including flow routing using APFC or FACTS devices.

Beyond these benefits and their respective measures, RSEs may need to look at other external factors in assessing the weight that needs to be applied to cost-related metrics. For example, the Los Angeles Department of Water and Power (LADWP) studied their pathway to comply with California's Senate Bill 100 (SB 100) in 2018. SB 100 requires establishing a 100% zero-carbon requirement for all retail electricity sales by 2045. LADWP observed that meeting this standard would require over $70 billion in investments.

After further analysis, LADWP observed that such massive investment needs could be seen as a financial risk and lower their credit rating by two notches; this potential drop in credit rating would, in turn, increase their cost of capital, ultimately impacting the utility's rates by 20% (from approximately 20 cents per kWh to 24 cents per kWh for the average residential customer) before making any actual expenditures. This mechanism could create risks and challenges for regulated companies and their investors and limit the investments that can be financed. Considering and mitigating such risks and their impact over the long run should be in the state's interest.

A similar mechanism can be seen for natural disaster risk. As the case studies in Section II.A: ATTs and *Seven Benefits – Benefit 6* highlight, ATTs (in particular, HPCs) are extreme-weather-proof and could help assure insurance companies that transmission providers are taking proper actions to cost-effectively mitigate risk, which could then lead to lower premiums.

Overall, the effectiveness of Order 1920 on ATTs will depend on how transmission providers implement the requirements of these Orders, including how they may consider long-term versus near-term benefits and solutions, evaluate the asymmetric risks of over- and under-building, and view flexible solutions as a way to reduce risks associated with various uncertainties (including costs) of future planning. The various levers provided to RSEs through Order 1920-A can help the states guide the transmission providers to develop a transmission planning process that is equitable and beneficial to all stakeholders, including the transmission provider, over the long run. This includes developing additional scenarios and selection criteria for the planning process, as discussed next.

D. Scenarios

Order 1920 requires transmission providers to develop at least three scenarios in their long-range planning processes for determining transmission needs. The Order also establishes that transmission providers must consult with RSEs on each of these planning components and establishes guidelines on the evaluation process and the development of criteria for the selection of transmission solutions, including that the benefits must be weighed against the costs.

Transmission providers must measure the *Seven Benefits* (at a minimum) when evaluating transmission solutions but have flexibility in the actual selection of potential solutions, including ATTs. This flexibility, while important, could lead transmission providers to develop selection processes that are biased – intentionally or not – against ATTs (or other technology types). For example, Order 1920 allows transmission providers to use qualitative assessments to select future solutions. This would allow transmission providers to disqualify ATTs based on qualitative statements, such as "technology is not mature enough" or "does not comply with the technical requirements," which are subjective and difficult to prove or disprove.[99] Furthermore, even if quantitative assessments are utilized, certain approaches – such as ranking solutions by maximum net benefits alone without any consideration for benefit-to-cost ratios – could bias the selection process away from lower-cost solutions, including ATTs.

98 *Southwest Power Pool, State of the Market 2019 (May 2020),* https://www.spp.org/documents/62150/2019%20annual%20state%20of%20the%20market%20report.pdf.

99 Order 1920 does require that the determination to not use any of the listed ATTs must include an "explanation that is sufficiently detailed for stakeholders to understand why [the ATTs] were not incorporated into selected regional transmission facilities" (P. 1,214).

Order 1920-A strengthens the role of the RSEs in the planning processes – particularly in scenario development and solution selection – by allowing states to suggest additional benefits to consider and giving RSEs and transmission customers the option to voluntarily fund a portion (or all) of a proposed transmission solution. RSEs can utilize these levers to guide transmission providers to be technology-neutral and cost-conscious while remaining objective and focused on state initiatives and consumer protection.

For example, Order 1920-A clarifies that RSEs can request a reasonable number of additional scenarios for transmission providers to consider (beyond the minimum three scenarios mandated in Order 1920). Order 1920-A implies that these additional scenarios can depart from Order 1920 requirements as long as they provide the information needed for cost allocation and other important factors for the respective states.

Thus, RSEs could request transmission providers develop a scenario that includes ATTs along with the three they are required to provide. Such an additional ATT-inclusive scenario will allow for a comparison of costs amongst the different solution portfolios. It also helps prevent the transmission provider from improperly "checking the box," such as by inappropriately comparing DLR only to a traditional wires-based solution over 20 years. When requesting such additional scenarios, RSEs may also consider requesting that the transmission provider assess transmission needs based on the broad benefits of ATTs, in addition to using benefits for evaluation and selection of potential solutions.

Another option made available to states is voluntary funding. Order 1920 requires transmission providers to consult RSEs when developing a process to allow stakeholders the opportunity to voluntarily fund either a portion or all of the cost of a potential solution that may otherwise not meet the selection criteria. RSEs could engage during the development of compliance filings to ensure the voluntary funding process allows states to fund ATTs as part of a solution to increase the benefit-to-cost ratio – in turn helping the ATT-inclusive solution meet the selection criteria and become more cost-effective overall.

One challenge with this approach is that, for transmission providers to calculate the benefits of the solution with the ATTs, they may need to perform additional modeling at the voluntary funding stage. Currently, Order 1920 does not mandate additional modeling under the voluntary funding provision and further details would need to be worked out.

The third and perhaps most effective option is for RSEs to get involved when the transmission provider develops its evaluation process and selection criteria, which are both needed for compliance filings at FERC. Order 1920 specifically requires the transmission providers to consult with and seek support from RSEs when developing the evaluation process and selection criteria.[100]

This state role, when combined with the other levers discussed earlier, could potentially allow states to advocate for certain selection criteria, such as benefits associated with certainty or optionality (as discussed earlier in Section IV.A: Benefit-to-Cost Ratio and Cost Certainties, Section IV.B: Optionality, and Section IV.C: Considerations Beyond Benefits). The states could also request the removal of any criteria that would bias the selection process against ATTs, such as qualitative criteria that are subjective and difficult to evaluate or rebut or rankings solely based on maximum net benefits without any consideration for benefit-to-cost ratios.

In parallel, states could consider developing policies that provide the transmission providers incentives that align with state policies.[101] For example, as discussed in Section II.B: Observations and Recommendations, costs (or service interruptions) are typically passed through to transmission customers and not directly felt by transmission providers. Thereby, incentives could encourage transmission providers to pursue these benefits, such as by allowing for a shared-savings approach when costs are reduced.

Examples of such incentives could include:

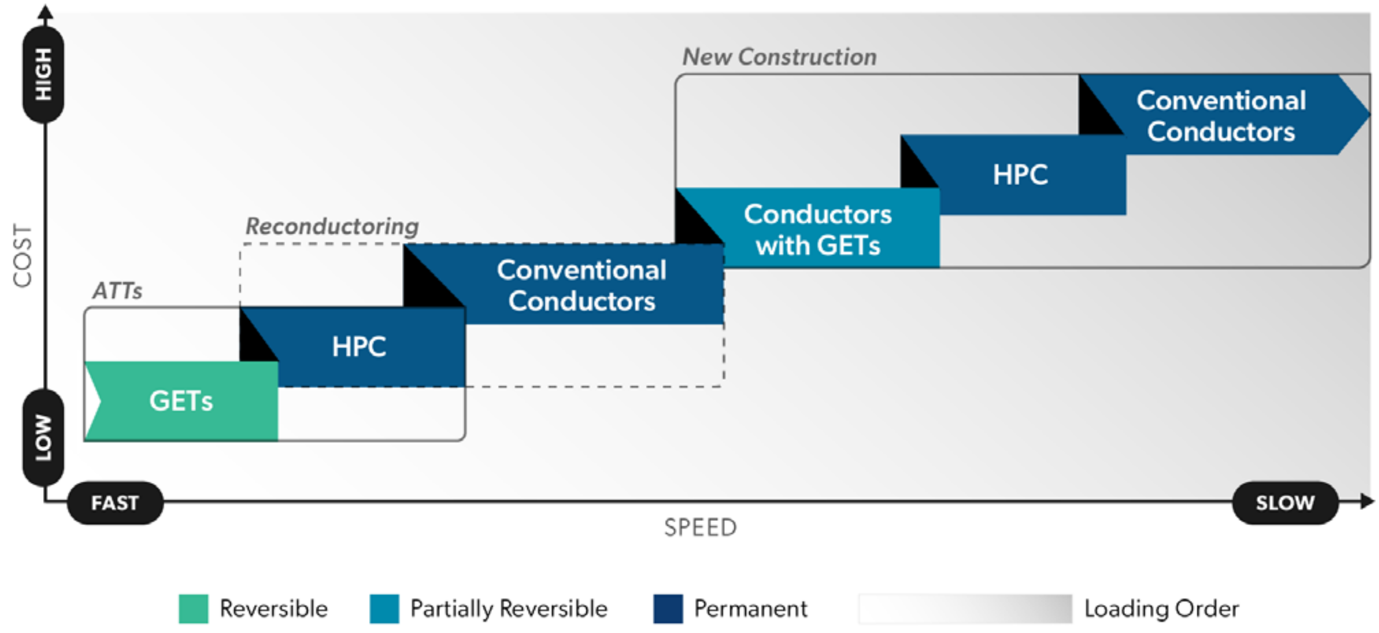
- ✓ **Incentives for reducing investment costs**

  This incentive could be applied to *Benefit 1* (Avoided or deferred reliability transmission facilities and aging infrastructure replacement) and *Benefit 7* (Capacity cost

100 For example, congestion costs do not always face the same state regulator scrutiny as capital investments, and transmission owners may not prioritize its avoidance. To circumvent this, RSEs could request that the solution selection process consider schedule certainty and reduced outages as an evaluation metric (as discussed in Section IV.A: Benefit-to-Cost Ratio and Cost Certainties).

101 See Appendix C for select examples of state policies.

FIGURE 17: ILLUSTRATIVE LOADING ORDER



benefits from reduced peak energy losses). *Benefit 2* (Reduced loss of load probability or reduced planning reserve margin) could also be considered for this incentive.

- **Incentives for reducing operational costs**

  This incentive could be applied to *Benefit 3* (Production cost savings), *Benefit 4* (Reduced transmission energy losses), and *Benefit 5* (Reduced congestion due to transmission outages).

- **Incentives for improving system reliability**

  This incentive could be applied to *Benefit 6* (Mitigation of extreme weather events and unexpected system conditions), which is rewarded when such adverse events happen.

These incentives are not necessarily limited to rewards but could also be in the form of penalties, such as for poor performance (e.g., when benchmarked against other transmission providers).

With these options available, RSEs could effectively develop a preferred loading order for transmission planning that aligns with state priorities. Examples of such loading orders may be ones that prioritize higher benefit-to-cost ratios (not necessarily for the immediate upfront costs, but rather for a longer-term) or lower-regrets solutions. To prioritize higher benefit-to-cost ratio options, the selection process may first optimize the existing grid (such as by using GETs), then upsize existing lines (such as through HPCs), and finally add new lines using conventional technologies when other technology options (including HPCs) do not make sense. Figure 17 illustrates a loading order.

Part of this approach may require establishing a "rule of thumb" in evaluating the potential solutions at a high level (more for screening purposes), such as prioritizing GETs for transfer increase needs of 20% or less and HPCs for transfer increase needs of 50% or more or when "right-sizing" opportunities are observed. A time or schedule-based approach, such as prioritizing GETs for immediate needs, may also be viable. The pre-screening cost threshold discussed in Section II.B: Observations and Recommendations is another rule of thumb that could be utilized. For finding lower-regrets solutions, the selection process may focus on mitigating costs and associated risks of not proactively right-sizing (by looking at the longer-term). It should be noted that any rules of thumb or heuristics should start as broad measures and then be refined and updated later as transmission planners gain more experience in evaluating various technologies, including ATTs.

However, establishing this preferred loading order with state input requires RSEs to review and understand the unique benefits ATTs could provide, including those beyond the *Seven Benefits* outlined in Order 1920, as discussed in the earlier sections.

V. Conclusion

FERC Order 1920 mandates transmission providers to develop scenario-based, long-term transmission planning that includes the consideration of ATTs. ATTs, as demonstrated through actual deployment and various studies, can offer cost-effective and faster-to-implement technology choices beyond traditional wires-based solutions. They show benefits for all *Seven Benefits* discussed in Order 1920, with some of the *Benefits* ranging from the tens to hundreds of millions of dollars a year per region. These *Benefits* could amount to several billions a year if deployed nationwide.

ATT's speediness and lower costs – and, for GETs, their portability and reversibility – provide additional benefits by addressing transmission needs faster than traditional wires-based solutions, leading to reducing costs for consumers sooner. Benefits also come in the form associated with time and risk avoidance that are perhaps harder to quantify in monetary terms. For example, ATTs (in particular, GETs) have much more certainty in costs and installation schedules than traditional wires-based solutions. They can also buy time and allow for flexibility and optionality – effectively allowing transmission planners to see how the future world evolves before making investment decisions. While such benefits are hard to measure and perhaps were never a material part of the traditional transmission planning process, they are real benefits that both the RSEs and transmission providers should acknowledge.

Despite these demonstrated benefits, barriers to adopting and considering ATTs as potential solutions for transmission planning remain. Common barriers include insufficient recognition of ATTs themselves and misaligned incentives; traditional planning approaches that tend to be static and deterministic; and the perceived lack of standardized data, tools, and analysis methodologies, along with human resources capable of carrying out advanced analyses. In addition, the case studies of ATTs and *Seven Benefits* highlight that the whole transmission planning process – including its analysis methodology and criteria – needs to evolve, which could be seen as an additional challenge layered on top of the four barriers.

These barriers should not be used as an excuse for impeding ATTs to be put on equal footing as the traditional wires-based solutions for purposes of the planning process that is being developed by the transmission providers. However, since Order 1920 leaves it to the transmission providers to develop scenarios, evaluation processes, and selection criteria, there is a risk that the process for assessing future transmission solutions will unfairly disadvantage ATTs.

With this in mind, RSEs should use the levers provided by Order 1920-A to demand greater transparency and flexibility in the long-term regional transmission planning process. To ensure a fair and equitable process, RSEs should participate in development starting at the early stages as transmission providers prepare their compliance filings. Participation can take the form of providing input into the scenarios, suggesting additional scenarios or benefits to consider, and opining on the evaluation process and selection criteria – all while using the tools RSEs may have. These tools include voluntary funding opportunities (including the option in Order 1920 allowing RSEs and transmission customers

to fund part or all of the cost of proposed transmission solutions) or potential legislative requirements, such as for evaluations of these technologies or incentives that will better align transmission providers against state priorities.

Integrating GETs and HPCs into transmission planning is not just an opportunity but a necessity for achieving cost-effective, sustainable grid development over the next several decades. FERC's framework provides a strong foundation, but proactive efforts from all stakeholders will be essential to overcome barriers, realize the full potential of all available technologies, and accelerate the industry transition. The success of Order 1920 will depend on the willingness of transmission providers to embrace these innovative solutions, modernize their frameworks, and deliver a grid development plan that is reliable, efficient, and ready for the future. The involvement of RSEs as a collaborator – and as a watchdog guiding the transmission providers in an objective manner –will be crucial in achieving success.

Appendices

A: GETs and HPCs

B: Traditional Transmission Planning Process

C: State Policies

D: Glossary

A. GETs and HPCs

This appendix provides more detailed descriptions of the various ATTs discussed in this document.

DYNAMIC LINE RATING

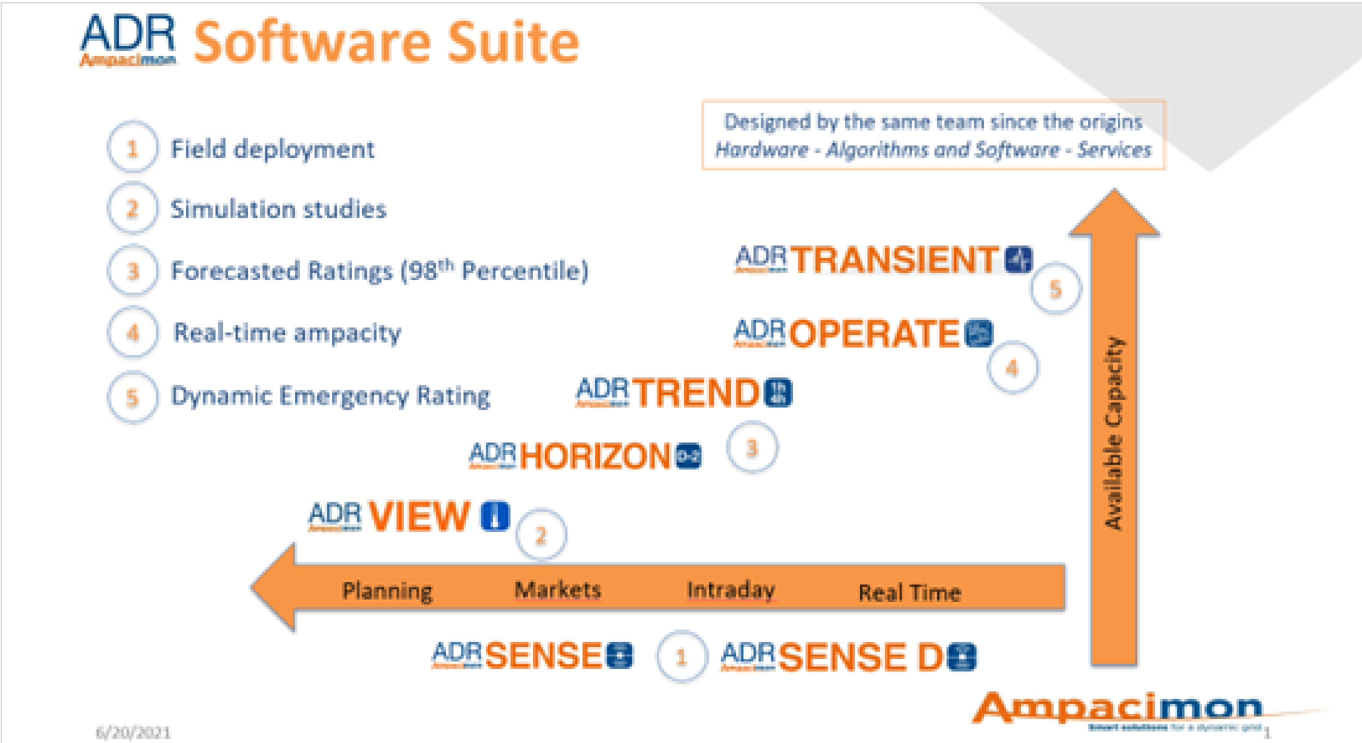
Dynamic Line Rating (DLR) systems monitor and adjust transmission line ratings in real-time based on system conditions rather than relying on pre-determined static ratings. Real-time system conditions can be assessed through measured sag of the lines, or calculations using measured environmental conditions – such as temperature, humidity, solar irradiance, wind speed and angle, and sometimes, vibration – to assess the sag of the line. The Institute of Electrical and Electronics Engineers (IEEE) and International Council on Large Electric Systems (CIGRÉ) devised standard thermal modeling of conductors for ampacity calculations. While many DLR vendors use them, the inputs are usually the "secret sauce" proprietary to the respective vendors.

The specific technologies and measurement approaches used for DLR also vary by vendor. Direct measurement methods use devices that are directly coupled to the transmission line. These devices measure temperature, tension, sag, and/or clearance from which the thermal rating is determined. CIGRÉ standards 207 and TB 209 TB 498 recommend direct measurements. Indirect measurement methods use weather stations and modeling. A unique approach includes measuring the vibration of the wires and "filtering out" vibration causes to calculate wind strength for any location within a given wire. Regardless of the approach, DLR systems require communication means through wireless networks, satellite, radio, or utility fiber cables (through substations), amongst others.

DLR technologies and products available in the market include software solutions, either as a standalone product or as an integrated package together with a hardware (sensors) solution. They provide interfaces that integrate with SCADA/EMS systems and offer customizable options for AAR and DLR, among other purposes (e.g., system awareness). NERC cyber security standards are implemented as they are widely accepted globally. Finally, the European Network of Transmission System Operators for Electricity (ENTSO-E) considers DLR methods and technologies to be "mature."

DLR vendors Ampacimon, Atecnum, Lindsey, and Heimdall offer systems that use sensors installed on the transmission lines. DLR vendor LineVision offers a system that uses a non-contact sensor mounted to lattice towers and monopoles rather than to live lines.

FIGURE A-1: DLR SOFTWARE



- Ampacimon's GridBoost™ suite combines software and hardware to measure overhead line capacity with high accuracy. The sensors capture critical physical characteristics to calculate real-time DLRs, integrating sag, mean conductor temperature, and perpendicular wind speed. Ampacimon provides solutions with virtual sensors and physical sensors, with the latter delivering higher performance and reliability. Virtual solutions may be suitable for optimizing budgets across larger networks with moderate capacity increase needs.

  Ampacimon's GridBoost Facility Ratings system enables users to manage equipment ratings, hierarchies, and calculations with full tracking and configuration. Facility-specific ambient-adjusted ratings are stored and can be analyzed against ambient temperature and solar conditions. These data can then inform 10-day hourly ratings derived from weather data.

- Atecnum's PowerDonut® 4th generation platform for DLR applications utilizes completely self-contained and self-powered sensors. The sensors capture voltage and current events and measure RMS current, RMS voltage, MW, MVars, conductor temperature, icing detection, and conductor sag. The Atecnum software can integrate locally available weather data from a public service provider for DLR application as well.

- Lindsey Systems' SMARTLINE transmission line rating platform uses direct measurements of conductor parameters to develop advanced learned behavior for determining line ratings. SMARTLINE then combines real-time and forecast weather to provide line-specific real-time and forecast AAR, DLR, emergency, and seasonal ratings suitable for transmission line facilities up through 765kV. SMARTLINE is available as a SaaS or on-premises solution and includes both real-time and forecast weather and flexible communication options.

- Heimdall's DLR technology (hardware and software) uses actual and direct physical and electrical line measures. The solution uses precision measurements at optimal locations along with line-specific, detailed weather modeling, advanced algorithms, and continuous learning to provide ratings throughout the grid. Heimdall's sensor platform is housed in a spherical housing (called the Neuron), which harvests its power from the line and has onboard programmable intelligence. It is uniquely designed as the first and only scalable DLR solution for the entire grid that utilizes actual, direct physical, and electrical line measurements. The solution comes with forecasting, emergency ratings, pre- and post-contingency planning, and integrated next liming elements. Localized live and forecasted weather inputs and modeling, along with circuit and conductor design inputs, are used in conjunction with the live sensor inputs for all real-time, forecasted, and contingency ratings.

- LineVision's LineRate™ Suite provides utilities with NERC CIP-compliant real-time, forecasted, and emergency DLRs via on-premises or cloud software options. LineVision's solution is a US-designed, engineered, and assembled non-contact LIDAR sensor that mounts quickly and securely to transmission structures rather than to live lines. This patented sensor technology dramatically increases the safety, operational efficiency, and accuracy of data models without interfering directly with the conductors. LineVision's DLR model combines computational fluid dynamics, forecasted and locally measured weather data, and sag-derived conductor temperature to offer increased capacity while reducing the risk of exceeding the maximum operating temperature of a thermally limited line.
- Prisma Photonics provides a powerline monitoring solution that uses existing optical fibers for AAR, DLR, and grid resiliency, covering thousands of miles with a substation-based deployment of the proprietary substation-installed Beacon unit. The system measures wind conditions on each powerline span for accurate line ratings and real-time alerts for extreme weather, wildfires, icing, electrical faults, and tampering.

  Using the PrismaPower Machine Learning AI models, Prisma Photonics analyzes data to distinguish events from background noise and pinpoint alerts to specific tower structures and spans. Alerts and ratings are delivered via the PrismaPower dashboard or integrated utility systems. For DLR, wind metrics and external weather data (e.g., solar irradiation and ambient temperature) are used to provide precise line ratings. Continuous monitoring ensures that the most critical span sets the line's capacity limit, reducing asset risks. This critical span is updated every 15 minutes for real-time decision-making.

Some vendors offer software-only solutions.

- Smart Wires, recognized for APFC solutions, offers SUMO, a software that optimizes grid capacity by providing real-time and forecasted thermal ratings based on weather conditions without requiring hardware sensors. This solution identifies spare capacity by using mezzo-scale and micro-scale weather data and supports icing prevention, asset monitoring, and increased transmission capacity, with a median increase of 15-20% over static ratings. SUMO can be integrated with its APFC software SmartValve™ to redirect power flows to utilize available capacity.

ADVANCED POWER FLOW CONTROL

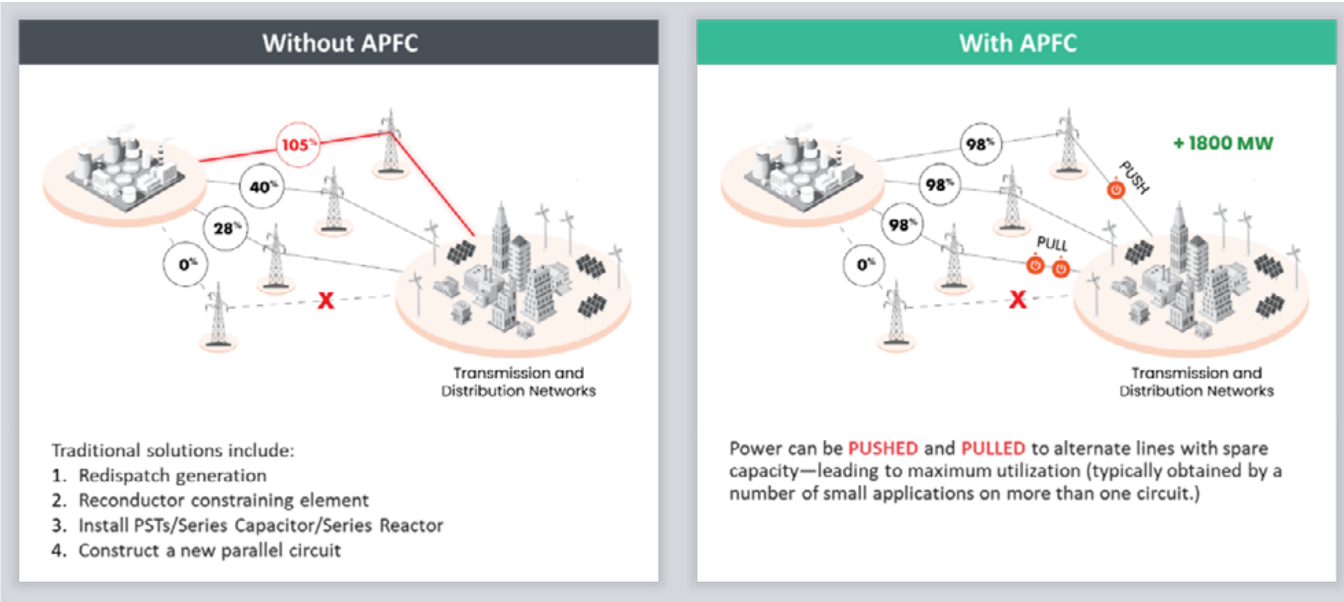
Phase shifters and phase angle regulators (PARs) devices have been widely accepted in the industry as a means to help the system operator control flow through a given path. The largest drawback of phase shifters/PARs is the cost; for example, a recently installed PAR between Michigan and Ontario has an annual carrying cost of over $10 million.

FACTS devices are power-electronic-based static devices that allow for flexible and dynamic control of flow on transmission lines or the voltage of the system. Some FACTS devices – such as series capacitors – alter the reactance of a line to control the flow (i.e., increasing the reactance will push away flows while decreasing the reactance will pull in more flow to the line). FACTs devices typically cost significantly less than PARs, can be manufactured and installed in a shorter time, are scalable, and, in many cases, are available in mobile form that can be easily deployed while providing flexible layout options.

- Smart Wires offers SmartValve, a modular Static Synchronous Series Compensator (m-SSSC) that injects voltage in quadrature with line current, enabling dynamic power flow control. It shifts power off overloaded lines or onto underutilized ones by synthesizing capacitive or inductive reactance. Figure A-1 below illustrates this effect.

  SmartValve is designed for rapid deployment and scalability, offering modularity and the ability to relocate to meet changing grid needs. Deployments are highly flexible, optimized for site-specific requirements (voltage, space, and environmental conditions), and scalable for future needs. SmartValve's compact design allows it to be distributed along circuits, minimizing environmental and community impacts. Its rapid delivery (12–18 months) and modular structure make it ideal for both long-term and urgent, uncertain grid challenges.

FIGURE A-2: ADVANCED POWER FLOW CONTROL (APFC)



TRANSMISSION SWITCHING

Transmission Switching is an elegant approach to flow control and is analogous to a car driver knowing ways to bypass congested roads under certain road conditions (such as during rush hours or during construction). It allows system operators to deliver power by circumventing the congested path. The "Switching" is done through operating circuit breakers (i.e., opening or closing).

Circuit breakers are capable of high-duty cycles and extremely reliable (failure occurs less than once in 20,000 switching cycles); some breakers – e.g., those connecting generating units with daily start and stop operations – are switched very frequently today.[102] Switching infrastructure is already in place, as most breakers are controlled remotely over the supervisory control and data acquisition system (SCADA) by the transmission owner (phone calls between the transmission owner and transmission operator to coordinate operations if the two are separate entities). The wear and tear costs of switching are estimated to be in the range of $10 to $100 per cycle.[103]

Switching has been practiced in the industry for quite some time and is typically based on operators' experience. Other means, such as the application of Topology Optimization software, could help develop more Switching solutions, especially as the grid evolves with changes in resources and loads accelerate. Such software can identify Switching solutions for temporary system conditions, such as during an outage.

- NewGrid offers the NewGrid Router, a software solution that helps to quickly identify Switching solutions under various system conditions. Solutions are validated with AC power flow and can consist of a variety of reconfiguration actions, including branch switching and generic substation reconfigurations. The search parameters can be tailored to reflect operational criteria, such as adding thresholds to the number of Switching actions permitted, limiting the Switching to certain assets (e.g., only assets with a nominal voltage level of 161 kV or below), and considering additional reliability constraints (e.g., maximum load allowed on a radial line) beyond standard contingency analysis. The software can also help assess the impact of an outage in advance.

102 For single-pressure SF6 breakers. Based on a CIGRE survey of 281,090 breaker-years with responses from 82 utilities from 26 countries, source: A. Janssen, D. Makareinisand C.-E. Sölver, "International surveys on circuit-breaker reliability data for substation and system studies," *IEEE Transactions on Power Delivery*, v. 29, n. 2, (April 2014), pp. 808–814.

103 All-in cost of maintenance overhauls for single-pressure SF6 breakers rated 72.5-362 kV.

FIGURE A-3: SKYLINE IMAGE OF CONVENTIONAL CONDUCTOR VS. SUPERCONDUCTOR

HIGH-PERFORMANCE CONDUCTORS

Much of the high-voltage transmission lines today use wires that wrap aluminum strands around a steel core, commonly known as Aluminum Conductor Steel Reinforced (ACSR). Newer designs, known as High-Performance Conductors (HPCs), use advanced composite-core conductors, rather than conventional steel, for a stronger yet smaller composite-based core. The smaller composite-based core of HPCs allows more conductive aluminum to fit within an equivalent diameter, thereby increasing the transfer capability of the wire. The composite-based core also reduces line sag.

There are various vendors offering a number of HPCs. Some of the HPCs have been deployed, while others are in the advanced development stage.

- CTC Global's advanced composite core conductors (ACCCs), which can carry 2x the amount of power than traditional conductors, have been successfully installed in more than 1,350 projects serving over 65 countries and 300 utilities. Projects range from 11 kV distribution line upgrades to 345 kV energized reconductoring projects to 1,100 kV new DC substations.
- TS Conductor's Aluminum Encapsulated Carbon Core (AECC) conductors can deliver 2x to 3x capacity of traditional ACSR conductors while eliminating the problems of stiffness that were common in earlier generations of advanced conductors. Through its innovative design, AECC maintains the same bending radius requirements as ACSR, making it fully compatible with standard installation and maintenance practices of today's mainstream ACSR wires.
- VEIR is delivering the next generation of high-temperature superconducting (HTS) electric transmission lines that operate with 5 to 10 times the transfer capacity of conventional lines at a given voltage level. More capacity at a given voltage means that VEIR lines can greatly increase the transfer capacities in existing transmission corridors and greatly reduce the space required for new corridors.

VEIR lines add much-needed capacity to the grid without triggering as many – or as onerous and time-consuming – siting and permitting requirements as conventional lines. Negligible losses enable VEIR's transmission lines to operate at levels of electrical current that are much higher than conventional lines. VEIR's solutions greatly reduce right-of-way requirements, unlocking new routes or accelerating permitting requirements. For example, a 138 kV VEIR overhead AC transmission line could carry the equivalent power of a conventional 345 kV line or upgrade capacity to 6,000 MW at the same voltage level. Figure A-3 compares the skyline image of a traditional 345 kV line capable of carrying 1,200 MW, VEIR's 138 kV superconducting cable capable of carrying 1,200 MW, and VEIR's 345 kV superconducting cable capable of carrying 6,000 MW, all using the same rights-of-way and towers.

B. Current Transmission Planning Processes

This appendix discusses the current (i.e., pre-Order 1920) transmission planning process that has been utilized by many transmission providers. The appendix provides a generalized discussion (which perhaps could be overly simplified), and the detailed approaches vary by transmission provider. This appendix reiterates content from Section III.A: Barriers for ATTs of the report, adding an illustrative example from the SPP's transmission planning process.

Many of the current (i.e., pre-Order 1920) planning processes used by transmission providers today are built on a deterministic framework that identifies transmission needs driven primarily by reliability requirements with some secondary consideration of public policy and economics drivers. These processes evaluate transmission solutions for a given planning time horizon, such as 10 years, and may contain interim target years. Diverse scenarios are often developed to reflect uncertainties in forecasting future system conditions, which allows for a transmission expansion plan that is sufficiently flexible to meet a variety of needs.

For example, the Southwest Power Pool (SPP) conducts its annual integrated transmission planning (ITP) to assess near- and long-term economic and reliability transmission needs.[104] The ITP produces a 10-year transmission expansion plan each year, combining near-term (year 2 and year 5), 10-year, and NERC transmission planning (TPL-001-4) assessments into one study. A separate 20-year assessment is performed once every five years. SPP will develop a single future for year 2, reflecting the limited uncertainty in a short time frame. SPP will then develop up to three futures consisting of a reference case and two additional future scenarios for years 5 and 10.

For reliability assessments, planners develop power flow models representing key system conditions during the target study years (such as summer peak and winter peak with high loads and shoulder seasons with low load and high renewables). Planners then simulate the system under each static snapshot. The simulations examine if the system meets the reliability standards and identify any transmission needs to maintain reliability, such as to remedy for thermal overloading, voltage violations, stability, and other issues observed from the analyses.

SPP develops a base reliability model set for all SPP planning processes, including transmission service, generator interconnection, and compliance studies. The key input assumptions for the models include expected resource generation level, non-coincident peak load forecasts, long-term firm transmission service usage levels, and transmission network.

Through reliability assessment studies, SPP evaluates the performance of its transmission system under normal and contingency conditions by analyzing facility thermal loading, voltage, dynamic stability, and short-circuit. SPP will utilize its planning criteria to determine if a potential violation should be considered as a reliability need.[105]

For economic assessments, most, but not all, regions run hourly (i.e., 8,760 hours per year) production simulations and identify transmission constraints with significant congestion costs. Planners also use these models to identify public policy drivers and other operational needs for transmission. Key input assumptions for the models include expected resources, load forecasts, long-term firm transmission service usage levels, and transmission network (and topology).

SPP performs economic needs assessments in parallel with reliability needs assessments to identify the economic needs of the system for each future scenario and study year. The simulation results will reveal constraints causing the most congestion and the additional cost of dispatching around those

104 The ITP is a regional planning process built to leverage knowledge of the transmission system's reliability, public policy, operational, and economic needs. SPP's ITP also addresses compliance, generator interconnection, and transmission service request impacts to develop a cost-effective transmission portfolio over a 10-year planning horizon. See Southwest Power Pool, *Integrated Transmission Planning (ITP) Manual, Version 2.17* (2024), https://www.spp.org/documents/72685/itp%20manual%20version%202.17.pdf.

105 Southwest Power Pool, *SPP Planning Criteria* (March 2024), https://www.spp.org/documents/71368/spp%20planning%20criteria%20v4.4.pdf.

constraints.[106] *SPP ranks the congested constraints of each future and study year to target a list of economic needs for the study by congestion score (defined as the product of a given constraint's average shadow price and the number of hours that constraint is binding.)*

In addition to the reliability and economic assessments, SPP performs public policy needs assessment to address the cases where the economic simulations identify conditions on the system that keep a utility from meeting its regulatory or statutory mandates and goals as defined by the renewable policy review and/or future specific public policy assumptions identified in the study scope.

Upon completing the analyses, planners solicit transmission solutions to address the needs identified, evaluate each potential solution, and make selections, often with stakeholder input. Potential solutions considered are typically traditional wires-based solutions, such as building new lines or upgrading existing ones. Non-wires technologies, such as FACTS, may also be considered as potential solutions in the evaluation process. However, not all technologies, including some of the ATTs discussed in Order 1920 or Order 2023, are recognized in this process.

After identifying the transmission needs, SPP will solicit solutions from stakeholders, including (1) transmission projects that require new, rebuilt, upgraded, or replacement facilities, (2) non-transmission solutions are generally considered technologies and methods that can complement the transmission grid in a predictable way, and provide certainties required for planning purposes.

For evaluation purposes, SPP calculates the one-year benefit-to-cost ratio and 40-year net present value (NPV) for economic evaluation and uses two metrics for reliability evaluation (i.e., cost per loading relief and cost per voltage relief.)[107]

Section 5.1.1.2 of SPP's ITP manual defines the non-transmission solutions as "technologies and methods that can complement the transmission grid in a predictable way, and provide certainties required for planning purposes." It considers FACTS and Power Flow Controllers (PFC) as technologies that can be used as non-transmission solutions but clearly states that DLR does not meet the definition of non-transmission solutions, preventing it from being considered as potential solutions in transmission planning.

106 Ibid., pp. 27–28.

107 SPP's Value of Transmission reports evaluates transmission projects using various metrics. See Southwest Power Pool, *The Value of Transmission Report: 2021 Edition* (March 2022), https://www.spp.org/documents/67023/2021%20value%20of%20transmission%20report.pdf.

C. State Policies

The barriers discussed in Section III.A: Barriers for ATTs are intertwined and will likely take some time to address. This appendix discusses policies developed by several states to address one or more of these barriers, such as by requiring transmission providers to evaluate ATTs (in particular, GETs) through legislative mandates.

Some states have directed utilities and relevant state authorities to study GETs and HPCs in state-level integrated resource planning or permitting processes. Other states are providing financial incentives or reducing financial risk for investments in transmission modernization where such action is legally sufficient and sustainable. It is good to see states creating an environment that encourages the implementation of GETs and HPCs.

States with existing or planned legislation directing utilities or state entities to study GETs and HPCs in state-level planning or permitting processes include California, Colorado, Montana, Virginia, and Maine.

California's Senate Bill 1006 (SB1006)[108] requires California utilities to evaluate GETs (DLRs, APFCs, and Topology optimization) at least every three years. Utilities are mandated to evaluate the cost-effectiveness of GETs for:

- Increasing transmission capacity
- Reducing transmission system congestion
- Reducing curtailment of renewable and zero-carbon resources
- Enhancing reliability
- Decreasing the risk of igniting wildfires
- Expanding capacity to connect new renewable energy and zero-carbon resources
- Improving flexibility to mitigate risks associated with technology and permitting uncertainties
- Enhancing optionality for load-serving entities

SB1006 also requires utilities to conduct a study every four years to identify transmission lines that can be reconductored using HPCs. The law requires the utilities to submit the ATT (i.e., GETs and HPCs) studies to CAISO and make them available to the public.

The Colorado Public Utilities Commission recently held a workshop to seek stakeholder input prior to proposing a similar rule to California's SB1006. The new rule would likely require Colorado utilities to "investigate the potential for economically efficient application of Advanced Transmission Technologies (ATTs, which is a synonym with GETs) throughout its transmission system for all assets operating at or above 100 kV." The rule is estimated to consider DLR, APFC, Topology optimization, carbon core conductor, superconductors, and energy storage as GETs.[109] The Colorado Commission's staff are also working with utilities to incorporate GETs and HPCs into their capital improvement plans and are considering allowing cost recovery for GET and HPC projects without express authorization and encouragement from the legislatures.

Montana passed a law in 2023 (Montana Code § 69-3-714) that includes efficiency performance criteria in its definition of advanced conductors – an overhead electricity conductor installed in a transmission or distribution project that has a direct current electrical resistance at least 10% lower than existing conductors of a similar diameter on the system. This law also outlines technical criteria for measuring efficiency savings, stating that "cost-effectiveness criteria … must be based on established direct current resistance at standard pressure and a temperature of 20 degrees Celsius."[110]

The Virginia legislation that passed in April 2024 requires utilities to include in their Integrated Resource Plan (IRP) filings

108 California State Legislature, Senate Bill No. 1006: "Electricity: transmission capacity" (September 26, 2024), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240SB1006.

109 See RMI comments posted 12/13/2024 in 23M-0472E on the Colorado Public Service Commission website, https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search, accessed December 31, 2024.

110 Montana Legislature, Montana Code Annotated § 69-3-714: 69-3-714. Criteria for allowable advanced conductor programs" (2023), accessed December 31, 2024, https://archive.legmt.gov/bills/mca/title_0690/chapter_0030/part_0070/section_0140/0690-0030-0070-0140.html.

"a comprehensive assessment of the potential application" of advanced transmission technologies and to provide a detailed explanation if such technologies are not included in the IRP.[111]

Maine passed legislation in 2024 requiring the Public Utilities Commission to conduct a review every five years of available grid-enhancing technologies "that could be implemented by a large investor-owned transmission and distribution utility to reduce or defer the need for investment in grid infrastructure in the State."[112]

Some jurisdictions have developed financial incentive policies and have seen utilities respond more positively to such "carrots" rather than "sticks." Since the offered financial incentives are then incorporated into the utility's rates and recovered from ratepayers, such incentives can create concerns about the total impact on affordability. One type of financial incentive is performance-based rates, which were recently considered in New York.

A draft bill[113] New York contemplated in 2024 that ultimately did not pass would have allowed a utility proposing capital improvements or additions to the transmission system to conduct a cost-effectiveness analysis of ATTs (both GETs and HPCs). If the utility found that the modernized technologies, alone or in combination with other capital investments, were more cost-effective than traditional technologies at achieving the utility's transmission goals, the utility could request a performance incentive mechanism for deploying the proposed solution.

States such as Minnesota and Utah have approved or at least discussed policies explicitly requiring utilities to include investment in ATTs as part of their resource or capital investment plans and allowing for cost recovery of any such technologies that are cost-effective.

The Minnesota legislation that passed in May 2024 directs all entities that own more than 750 miles of transmission lines in the state to submit every two years a technical and cost-effectiveness evaluation of GETs that can be used to solve certain grid concerns.[114] Specifically, the transmission owners must: 1) identify areas of congestion over the past three years and projected congestion for the upcoming five years; 2) project the increased cost to ratepayers due to congestion; 3) estimate the feasibility, cost, and cost-effectiveness of installing GETs to address congestion; and 4) propose an implementation plan to install GETs at congestion points. The policy explicitly authorizes the Minnesota commission to approve cost recovery, including a rate of return, on "any prudent and reasonable investments made, or expenses incurred" in administering and implementing the GETs implementation plan.

Utah similarly considered (ultimately unsuccessful) legislation in 2024 that would have directed utilities proposing additions to or expansion of the transmission system to include an analysis of the cost-effectiveness of deploying GETs to meet electric system needs; the bill also would have authorized the Public Service Commission to approve cost recovery if it deemed the deployment of the identified advanced technologies to be cost-effective.

Finally, some states are considering legislation that would exempt utilities from permitting requirements for advanced reconductoring, which has been demonstrated in California as a driver for advanced conductor installation by Southern California Edison. Instead of the lengthy permitting process, in these cases, the utilities are only required to notify the authorities through the more informal process of filing an advice letter.

111 Virginia General Assembly, *House Bill 862 (2024 Regular Session)*,accessed December 31, 2024, https://legiscan.com/VA/bill/HB862/2024.

112 Maine State Legislature, *Senate Paper 257, Legislative Document 636 (131st Legislature)*, accessed December 31, 2024, https://legislature.maine.gov/legis/bills/getPDF.asp?paper=SP0257&item=3&snum=131. See Item Periodic Review required under Section 2.

113 New York State Legislature, Assembly Bill A9105, Amendment A (2023 Session), accessed December 31, 2024, https://www.nysenate.gov/legislation/bills/2023/A9105/amendment/A.

114 Minnesota Legislature, House File 5247 (2024 Session), accessed December 31, 2024, https://legiscan.com/MN/text/HF5247/id/3000727.

D. Glossary

ACCC	Aluminum Conductor Composite Core
ACORE	American Council on Renewable Energy
ANOPR	Advanced Notice of Proposed Rulemaking
APFC	Advanced Power Flow Control
ATT	Alternative Transmission Technology
Brattle	The Brattle Group
CAISO	California ISO
Commission	Federal Energy Regulatory Commission
DER	Distributed Energy Resources
DLR	Dynamic Line Ratings
DOE	US Department of Energy
EF	The Enhanced Fujita Scale
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
EMS	Energy Management System
EPM	Empresas Públicas de Medellin
EV	Electric Vehicle
FACTS	Flexible Alternative Current Transmission Systems
FERC	Federal Energy Regulatory Commission
GET	Grid Enhancing Technology
GRE	Great River Energy
GW	Gigawatt (1,000,000,000 Watts)
HPC	High-Performance Conductor
HVDC	High Voltage Direct Current
ITP	Integrated Transmission Planning
IRP	Integrated Resource Plan
INL	Idaho National Laboratory
ISO-NE	ISO New England
kV	Kilovolt (1,000 Volts)
LADWP	Los Angeles Department of Water and Power

LCR	Locational Minimum Installed Capacity Requirements
LOLP	Loss of Load Probability
OKGE	Oklahoma Gas and Electric
MW	Megawatt (1,000,000 Watts)
MWh	Megawatt-hour (1,000,000 Watts-hours)
NEPOOL	New England Power Pool
NESCOE	New England States Committee on Electricity
NOPR	Notice of Proposed Rulemaking
NPV	New Present Value
NYISO	New York ISO
OATT	Open Access Transmission Tariff
PAR	Phase Angle Regulator
PFC	Power Flow Controller
PJM	PJM Interconnection
PPL	Pennsylvania Power and Light
RMI	Rocky Mountain Institute
RTO	Regional Transmission Organization
RPS	Renewable Portfolio Standard
SB100	California's Senate Bill 100
SB1006	California's Senate Bill 1006
SCE	Southern California Edison
SENY	Southeast New York
SPP	Southwest Power Pool
T&D	Transmission and Distribution
TPL	Transmission Planning (NERC Standard Family)
TPP	Transmission Planning Process
UPNY	Upstate New York
VPP	Virtual Power Plant
Zone J	New York City zone (within New York ISO)