COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid and New England Power Company	)	D.P.U. 25-69

NATIONAL GRID COMMENTS ON ORDER

Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, and their transmission operator and affiliate, New England Power Company,[1] collectively referred to for purposes of these Comments as the Companies, offer these comments to the Department of Public Utilities (Department) in response to the Department's June 2, 2025 Vote and Order Opening Investigation Into the Use of Advanced Conductors, Grid-Enhancing Technologies and Other Advanced Transmission Technologies to Enhance the Performance of the Commonwealth's Transmission System in Applications that are Subject to Federal Jurisdiction, Pursuant to St. 2024, c. 239, § 121 (Order).

1 New England Power Company (NEP) builds, maintains, and operates roughly 2,400 circuit miles of electric transmission facilities in Massachusetts, New Hampshire, and Vermont. National Grid plc, on behalf of NEP and other National Grid affiliates, has participated in and has filed comments in the FERC docket related to the Advance Notice of Proposed Rulemaking ("ANOPR") on Implementation of Dynamic Line Ratings issued by the Federal Energy Regulatory Commission on June 27, 2024, in Docket No. RM24-6-000. The transmission issues touched upon in that proceeding and in these comments are generally regulated by the Federal Energy Regulatory Commission (FERC).

I. GENERAL COMMENTS

The Companies and their New York affiliates operate electric distribution networks and transmission networks in New England and New York, respectively. The Companies' United Kingdom (UK) affiliate operates electric distribution and transmission networks in the UK. The Companies and their affiliated companies share learnings.

A proven industry leader in integrating innovative technologies to better serve customers, the Companies are strong proponents of grid-enhancing technologies (GETs), advanced conductors, and other innovative transmission and distribution technologies, and their potential roles as part of a cost-effective network operation for customers. These comments are based on the Companies' and their affiliates' experience in evaluating and deploying GETs and advanced conductors, which is the focus of these Comments.

In support of innovation, National Grid plc's subsidiary, National Grid Partners (NGP), actively evaluates and brings forward emerging distribution and transmission technologies, including leading disruptors across the spectrum of GETS and advanced conductors. The Companies have access to these technologies, and, along with other utilities, have the ability to shape the technologies to meet the best use cases for their networks. NGP's remit extends far beyond the Companies' immediate service territories, including leading a peer utility network, the NextGrid Alliance,[2] that brings together over 130 utilities with new emerging technology vendors. NGP, which is a non-regulated subsidiary of National Grid plc funded entirely at shareholder expense, does invest in innovative technology

[2] NextGrid Alliance is a global peer utility network of over 130 utilities whose focus is on advancing innovation in the utility industry through collaboration.

companies, but the Companies maintain strict policies around procurement and vendor selection and there is no bias for or against NGP's portfolio companies.

The Companies have first-hand experience through deployment of GETs and advanced conductors on distribution and transmission networks. As noted above, the Companies' affiliates in New York and the UK share learnings and best practices from their first-hand experience with GETs and advanced conductors with the Companies. These projects have demonstrated that when deployed in the right circumstances, GETs and advanced conductors can contribute quantifiable improvements in system capacity, operational flexibility, and renewable energy integration. The Companies emphasize that GETs should be implemented through a targeted and systematic approach where doing so provides clear customer and grid benefits, following a thorough review of network constraints. Some examples of these deployments (each of which are described in more detail below) include:

- Dynamic line rating (DLR) technologies;
- Advanced power flow control (APFC) technologies;
- Network topology optimization and planning tools; and
- Advanced conductors, including aluminum conductor steel supported (ACSS), aluminum conductor composite reinforced (ACCR), aluminum conductor composite core (ACCC), and aluminum encapsulated carbon core (AECC) conductors.

The Companies' experience demonstrates that GETs and advanced conductors have the potential to provide substantial value to customers and the grid when deployed in the appropriate circumstances. The Companies, however, reiterate that GETs and advanced conductors are among several important tools for the utilities to consider in a growing toolkit, and that there are particular use cases where such technologies may be relatively more applicable. Key findings include:

- **GETs and advanced conductors today have the most significant potential for mitigating transmission network constraints**, though there are some developing distribution applications as well.
- **GETs and advanced conductors are not one-size fits-all** and different technologies can help to address different use cases on different parts of the transmission and distribution networks.
- **GETs and advanced conductors tend to have a stronger case for cost-effectiveness in Independent System Operators (ISOs) and Regional System Operators (RTOs) areas with significant levels of congestion or load growth** that is expected to exceed capacity. ISO New England (ISO-NE) currently has low congestion compared to other ISOs/RTOs.
- **GETs are not well-suited to solve asset condition issues**, although they are considered as part of designs for replacement of aging equipment. A substantial portion of transmission investments in New England are driven by asset condition constraints.
- **Advanced conductors are better suited to solve asset condition issues** and the Company and NEP consider them in the asset condition solution evaluation process.
- **GETs and advanced conductors are improving in cost-effectiveness**, but the cost premium to deploy certain GETs and advanced conductors may not be the most prudent solution to a particular grid need based on today's ISO frameworks.
- **GETs and advanced conductors are continuing to evolve** and should continue to be evaluated.

These comments are based on the Companies' experience in evaluating and deploying GETs and advanced conductors. GETs and advanced conductors will play an evolving and important role on the Companies' distribution and transmission networks. The Companies continue to gather learnings on how these technologies could support policy and reliability goals in Massachusetts and continue to engage in regional and national stakeholder processes, including those led by ISO-NE and the Federal Energy Regulatory Commission (FERC), to support coordinated advancement of cost-effective solutions for customers.

For the reasons discussed in more detail below, the Companies consider the benefits of these technologies to be highly dependent on the specific system need and deployment location. In the Companies' experience, these technologies are only cost effective where application strategies are well-aligned with system characteristics and where site-specific analysis confirms operational and economic feasibility. The Companies recommend that consideration of GETs and advanced conductors continue to be integrated into regional transmission planning processes, where cost-effective evaluations can be conducted transparently and inclusively.

The Companies are deeply committed to exploring ways to achieve capital efficiencies, including via integration of new technologies like GETs and advanced conductors, to pass on the associated cost and time reductions to customers.

III. Specific Comments in Response to the Department's Questions to Electric Distribution and Transmission Companies

The Companies offer the following specific comments in response to the Department's questions to electric distribution and transmission companies in Section IV.B. of the Order.

1. Has the Company conducted any analysis or evaluation of advanced conductors, grid-enhancing technologies (i.e., dynamic line ratings, power flow controllers, topology optimization), or other advanced transmission technologies to deploy on its transmission or distribution grid?

a. Please describe each advanced transmission or distribution technology the Company has evaluated and summarize the main findings.

The Companies have evaluated the following advanced transmission and/or distribution technologies:

Dynamic line ratings (DLR). DLR refers to technologies that enable transmission operators to see in the real time the actual, or close-to-actual, capacity ratings of their transmission lines based on the specific conditions at the time (rather than a static rating based on average conditions). The Companies and their affiliates have pursued integration of DLR on two 115 kV lines in Rhode Island, as well as on four 115 kV lines in Western New York. The Companies have also proposed DLR on transmission lines that would help integrate offshore wind into Massachusetts. The Companies' findings suggest that deployments of DLR can increase capacity for some transmission line segments by 10-20%. The increased capacity benefits are more impactful at higher voltages (e.g., a 10% increase on a 345 KV line translates to significantly more MW capacity than a 10% increase on a 115 KV line), whereas the installation costs are comparable regardless of the voltage level. As described below in response to question #2 part (b), the benefits from DLR may be highly site-specific, especially in instances where the Companies have already deployed Ambient Adjusted Ratings (AAR) and question #3.

Advanced power flow control (APFC). APFC technologies are physical devices deployed at substations that can change the impedances of equipment in real-time to divert energy flow from congested lines to uncongested lines. The Companies have Field-tested Smart Wires power flow control technology on two 69 kV lines in Massachusetts. APFC technologies have shown to improve the utilization of existing assets, particularly where constructing new infrastructure is time-consuming or challenging, by redirecting flows away from constrained lines and thereby supporting system reliability during periods of high congestion or outage scheduling.

Network topology optimization and planning tools enable enhanced transmission planning load flow analysis and control center system reconfiguration based on real-time network conditions. Today, the Companies leverage Siemens' Power System Simulation for Engineering (PSS/E) high-performance transmission planning and analysis software, which has to optimize network planning and topology to ensure system reliability, security, and regulatory compliance. This software has continued to make regular incremental improvements to help transmission planners conceptualize a range of different types of solutions, including to model dynamic switching of devices on the distribution system to avoid transmission overloads. The Companies continue to assess industry software that may assist in network optimization in both planning and operations, with consideration of the increasing saturation of load and generation models complicating the process.

Advanced conductors can greatly increase the transfer capacity of existing transmission rights-of-way. The Companies have evaluated multiple different types of advanced conductors, each with different potential applications and cost-profiles. These technologies also vary in terms of commercial viability. The advanced conductors with which the Companies have experience include:

- ACSS conductors are designed for high-temperature operation with fully annealed aluminum strands, offering greater current capacity and reduced sag compared to the more conventional and more widely-deployed aluminum conductor steel-reinforced cable (ACSR) conductors. ACSS conductors are at a high level of commercial readiness.
- ACCR conductors use a high-strength aluminum matrix core, offering higher current capacity, lower thermal expansion, and reduced sag compared to ACSR conductors.

- Carbon composite-core conductors, such as CTC Global's ACCC conductor and TS Conductor's AECC conductor, use a lightweight, high-strength carbon fiber core that enables a two-to-three-times higher current capacity, lower thermal sag, and improved efficiency over traditional ACSR conductors. Carbon composite-core conductors are at a medium-to-high level of commercial readiness.
- Superconducting-based power lines, such as VEIR's overhead superconducting power line solution, can achieve up to a five-fold increase in transfer capacity relative to ACSR. Superconducting power lines are at a low level of commercial readiness.
- Advanced conductor technologies and deployment across the industry have primarily been focused on transmission-level use cases. The Companies are interested in exploring some of the emerging advanced conductor technologies that could be used to address distribution-level use cases as well.

Phase balancing. The Companies are evaluating Switch Source's Phase-EQ™ technology for potential deployment on distribution feeders. These feeders, operating at 4–15 kV and wye-connected, can experience significant phase imbalance due to uneven single-phase load growth, including rooftop solar and electric vehicles. Phase-EQ enables dynamic phase balancing across all three phases, which can enhance voltage stability, increase DER hosting capacity, and defer more traditional reconfiguration work.

b. Provide a list of the transmission and distribution technologies that the Company considers mature, commercially available, and ready for integration into utility planning and grids

Subject to site-specific engineering assessments, The Companies consider the following technologies to be commercially available and mature for integration:

- Dynamic line rating technologies (sensor-based and weather-based);
- Advanced power flow control devices;
- Topology optimization and planning tools;
- Certain advanced conductor technologies, including ACSS and ACCR (more mature) and ACCC/AECC (less mature); and
- Phase balancing automation (e.g., Phase-EQ).

It should be noted that GETs and advanced conductors are rapidly evolving technologies and the list of commercially viable solutions is likely to grow. In addition, the Companies expect to see technologies such as Advanced conductors and DLR become available commercially as a single solution. This is likely to enhance to the utilization of these technologies on the grid.

2. Has the Company conducted any cost benefit or total cost of ownership analyses for the technologies?

The Companies have assessed cost-effectiveness and deployment criteria for multiple technologies. These analyses have demonstrated that benefits vary significantly depending on several factors, including site conditions, existing system configuration, and the need being addressed.

a. Under what circumstances would these technologies be more cost effective than conventional transmission or distribution upgrades?

The Companies continually evaluate the technologies and standards utilized to determine proposed upgrades on the transmission and distribution system. As a function of this process, the use of an advanced conductor has become a standard for the Companies, so that new network builds are robust to uncertainties in projected load growth out to 2050. As described in more detail in response to question #3 below, the Companies will also be imminently installing Ambient Adjusted Ratings (AAR) across their transmission network per FERC Order 881,[3] which will require a new rating to be calculated for every hour for every transmission element, relative to both the season and ambient temperature for that element, at that time. The application of this dynamic ratings protocol on the transmission system will increase reliability and significantly enhance the available capacity on transmission lines.

[3] *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 (2021).

In the chart below, the Companies describe several circumstances that may improve the cost-effectiveness of particular technologies, which are typically highly site-specific:

Circumstance	DLR	APFC	Topology Optimization	Advanced Conductors	Phase Balancing
Circuits with low-to-moderate congestion and/or installed Advanced Ambient Ratings (AAR)				X	
Circuits with congestion caused by planned outages or temporary constraints	X	X	X	X	
Areas with sustained wind speeds above 3 meters per second	X				
Technology deployment may defer reconductoring or substation upgrades	X	X	X	X	X
Transmission structures and lines are approaching end of useful life and need to replaced			X	X	
High penetration of DER in the area	X	X	X	X	X
High expected load growth, yet limited Right-of-Way access		X	X	X	

Note: "X" indicates that the presence of a particular circumstance would help improve the relative cost-effectiveness of a particular technology.

b. Can these technologies help to avoid or delay the need for building new power lines or substations?

While the development of new transmission lines and substations is required to meet the increasing electric load growth from electrification of transportation and buildings, and to enable increasing renewable energy in the electric grid, the implementation of GETs can, in certain instances, help maximize the use of existing infrastructure and help defer development of new transmission infrastructure, as discussed below.

DLR may help to defer major infrastructure investments. DLR installations can often be completed within six months, whereas the planning and construction of new transmission lines or substations can take many years, and even a decade or more. DLR, which in some instances (given the right conditions) can increase capacity by 10-20%, may serve as an interim solution to address immediate constraints while longer-term solutions are developed. A key learning from the Companies' deployment is that the improved system awareness from DLR can also help to identify situations in which the assumed static ratings are too high. Thus, DLR can help identify assets under increased stress that if left unmitigated could be at the risk of failure.

APFC technologies may also enable better utilization of existing assets, providing flexibility during extended upgrade planning and implementation. APFC can defer the need for building new transmission lines by improving utilization of the existing transmission system. In particular, APFC can support flexibility during network upgrades where building parallel lines or expanding existing infrastructure may be cost-prohibitive or delayed.

Advanced conductors may help avoid or defer short-term transmission or substation construction and can improve the efficiency of reconductoring, depending on the site-specific needs. For instances in which existing structures have significant remaining asset life, advanced conductors can eliminate the need to replace structures. (The conductors are often compatible with existing structures given their specifications.) For instances when both reconductoring and structural replacement are needed, advanced conductors, including ACSS, ACCC, and AECC, can help reduce the number of new structures needed since the lines can span a greater distance without sagging. However, depending on the circumstance, long term asset condition and capacity needs may determine alternative solutions to be the most prudent.

c. Do these technologies support Massachusetts climate goals and clean energy objectives?

Yes, DLR, APFC, topology optimization, and advanced conductors can support the Commonwealth's climate and clean energy goals by increasing system flexibility, reducing transmission congestion, facilitating integration of renewable generation, and minimizing curtailment. These technologies also improve access to lower-cost, zero-carbon electricity by enabling more efficient use of existing infrastructure.

However, the benefits of these technologies are highly dependent on the specific system need and deployment location. In the Companies' experience, these technologies are only cost effective where application strategies are well-aligned with system characteristics and where thorough, site-specific, analysis confirms operational and economic feasibility. As such, the Companies support continued evaluation of GETs and advanced conductors through structured planning processes, including those led by ISO-NE, to ensure deployment aligns with climate policy while maintaining cost effectiveness and system reliability.

The Companies also recognize that the deployment of certain GETs and advanced conductors introduces new operational and cybersecurity risks. For example, APFC devices add power electronics to the grid, often in publicly accessible or "outside-the-fence" areas, which can increase exposure to cyber and physical security threats. The Companies' UK affiliate deployed Smart Wires technologies and observed that siting and protection of these assets required careful planning and coordination to meet cybersecurity standards. Lessons learned from these projects continue to inform the Companies' internal standards and risk mitigation strategies in Massachusetts (and those of their New York affiliate).

d. Has the Company identified any locations in Massachusetts where these technologies should be prioritized?

The Companies have adopted the use of ACSS conductor, an advanced conductor, as standard practice across its Massachusetts transmission operations and continues to evaluate the application of other advanced conductors for each project. The Companies note that ISO-NE is well positioned to conduct regional system reviews to determine where these technologies may be most beneficial, including identifying system capacity needs and areas of high congestion. Additionally, the Companies are currently in the initial stages in evaluating Switch Source's Phase-EQ™ technology on select Massachusetts distribution feeders. The Companies also proposed DLR for the circuits feeding the proposed Brayton Point Offshore Wind Hub project and was selected for a federal award under the Infrastructure Investments and Jobs Act (IIJA).[4]

[4] PowerUp New England, the parent awardee for the Breyton Point Project, was awarded as part of the Grid Resilience and Innovation Partnerships in October 2024. The project is currently under review by the Department of Energy.

3. Has the Company conducted any pilots, demonstration projects, or feasibility studies for these technologies within Massachusetts or other jurisdictions?

As noted in response to question #2, the Companies have adopted the use of ACSS conductor, an advanced conductor, as standard practice across their Massachusetts transmission operations. The Companies haves found that use of lighter weight advanced HTLS conductors allows at least a doubling the capacity of existing lines while limiting the number of existing support structure modifications / replacements.

The Companies are also imminently deploying Ambient Adjusted Ratings (AAR) across their transmission network per FERC Order 881. AAR methods rely on weather-based data and can provide conservative yet enhanced line ratings without the need for physical sensor deployment required for DLR. For instance, AAR will shift the Companies from using 80,000 transmission element ratings across its transmission system to 960,000 transmission ratings. Thus, AAR may achieve some similar operational goals to DLR, with lower capital cost and integration complexity.

The Companies have provided below brief descriptions of their experience with other advanced technology deployments in Massachusetts and New York.

Example Project #1 – ACCR deployment in Massachusetts

The Companies deployed 3M's ACCR advanced conductor on the A127/B128 115 kV transmission lines in Massachusetts. The project addressed the need to uprate line capacity while leveraging existing structures that remained in good condition. Under traditional reconductoring approaches, The Companies would have needed to replace several double-circuit towers to accommodate the increased thermal rating. By utilizing

ACCR, The Companies were able to avoid these structure replacements, significantly reducing project cost and construction time.

Example Project #2 – APFC deployment in Central Massachusetts

The Companies deployed Smart Wires APFC devices on two 69 kV lines. During the field testing of the APFC, studies showed improved line flows, although additional testing and refinement of relay settings and modeling tools are needed to fully understand the benefits of deploying across the transmission network.

Example Project #3 – Switch Source Phase-EQ deployment in Massachusetts (planned for 2025)

The Companies plan to deploy Switch Source Phase-EQ on a limited number of distribution circuit(s) in Massachusetts. Switch Source Phase-EQ is a distribution automation tool, designed to dynamically balance phases on 4–15 kV distribution feeders. The project is intended to improve distributed energy resource (DER) hosting capacity and support grid modernization goals.

Example Project #4 – DLR deployment in New England, New York, and United Kingdom

The Companies installed DLR on two 115 kV lines in their New England service territory and evaluated the effects of DLR. While a there was a circuit capacity increase noted from the deployment, the benefit of the DLR have been somewhat limited in practice based on the absence of congestion on the system. The pilot also proved useful in being able to assess that while the circuit capacities increased, the operation to these new parameters were limited by other potential network constraints (including thermal limitations in a substation and voltage limitations). This was a valuable take-away that the Companies will consider in its implementation of Ambient Adjust Ratings.

The Companies have installed LineVision sensors on four 115 kV lines in New York in a renewable energy rich region, including a 125-MW utility-scale wind energy project. The DLR deployment is integrated with the Companies' Energy Management System (EMS) to enable real-time and forecasted line ratings.

The projects have resulted in benefits, including a 10–20% capacity increase, improved situational awareness, and early detection of conductor issues. While DLR offers real-time situational awareness and the potential for substantial capacity increases, Companies note that in some cases, Ambient Adjusted Ratings (AAR) may achieve similar circuit capacity increases, absent the capital and operational spend that accompanies DLR installations. The Companies consider AAR to be a cost-effective solution in situations where full DLR deployment is not justified based on system need, asset age, or congestion profile.

Additional findings suggest that the cost-effectiveness of DLR may vary on a case-by-case basis and requires robust communication infrastructure and span-specific planning. Realizing the full benefits of DLR will require upgrades to the Companies' EMS capabilities as well. The Companies recognize that new opportunities for DLR could emerge in the future, including from large loads and large-scale renewables, and will continue to assess the profile of future transmission needs for DLR.

In addition to the Companies' US experiences, National Grid in the UK has considerable experience with DLR, targeting its initial deployments along several areas of high congestion across the UK. The windy conditions along these circuits have resulted in substantial capacity ratings increases in the 20%-30% range. Since there is significantly more congestion in the UK, the increased ratings achieved from DLR in the UK have resulted in significant cost savings for customers. Based on these positive outcomes, National Grid has plans with the UK transmission system operator (NESO) to scale DLR to additional congested circuits across its system beyond the initial deployments. The experience in the UK demonstrates the Companies' and their affiliates' collective confidence in DLR as an impactful technology that can deliver customer benefits under the right conditions. As new use cases for DLR emerge in New England in the future, the Companies will leverage learnings from their UK and New York counterparts.

4. Are there quantifiable benefits to Massachusetts ratepayers from the implementation of these technologies?

GETs and advanced conductors can provide quantifiable benefits, including cost savings for ratepayers when deployed cost-effectively to address site-specific needs.

Other benefits could include reduced congestion, increased renewable hosting capacity, improved operational flexibility, and improved reliability. The magnitude of benefits to ratepayers depends on the application context, including system configuration, demand patterns, and timing. The Companies support further evaluation through ISO-NE's planning process to identify opportunities in Massachusetts where these technologies may provide value.

The Companies evaluate technologies using the following criteria:

- Total cost of ownership and asset longevity;
- Estimated production cost savings;
- Ability to meet identified system needs;
- Alignment with state policy goals and customer affordability.

5. What are the primary barriers and/or implementation concerns that may prevent a wider adoption of such technologies?

The Companies have identified several key barriers that may impact the pace and scale of wider adoption of GETs and advanced conductors. These include:

Grid needs cases. As discussed in response to question #2, the cost-effectiveness of different GETs and advanced conductors will depend heavily on the circumstances and needs of the electric transmission and distribution systems, which may vary by location. For instance, the New England transmission network today has relatively low congestion compared to other ISOs/RTOs, which may reduce the needs case for certain advanced technologies relative to others.

Policy and regulatory. As discussed in the response to question #6 below, GETs and advanced conductor deployment are subject to the ISO-NE transmission planning process. Additionally, there is a need to ensure that North American Electric Reliability Corporation (NERC) standards around Critical Infrastructure Protection (CIP) and Facilities (NERC-CIP and NERC-FAC standards, respectively) reflect implementation of GETs and advanced conductors. For instance, the Companies have actively collaborated with the US Department of Energy Idaho National Laboratory (INL) to incorporate cybersecurity standards into deployments of DLR and power flow devices to comply with NERC-CIP, and INL has developed industry wide standards for utilities to deploy these technologies.

Systems to enable interoperability of new technology. As the industry integrates GETs and advanced conductors, these technologies need to be integrated into various adjacent planning and operational processes and systems. For instance, as discussed in the response to question #3, realizing the full benefits of DLR may require changes to enable expanded functionality in the Companies' Energy Management System (EMS).

Technology maturity and standardization. Relatively more nascent technologies may face barriers related to high costs and limited data. As technologies continue to mature and evolve, the costs of such technologies may decrease over time, improving their cost-competitiveness relative to traditional reinforcements. Relatedly, as technologies mature, there may be better data available on such technologies and more collective certainty across the industry for how to integrate such technologies into standardized planning processes.

Maintenance and workforce development. Adoption of new technology may require new training for utility field workforce to safely and effectively maintain and operate such technologies, especially during emergency response/storm restoration. Relatedly, new technology adoption may result in changes to maintenance costs that could impact lifetime costs and the associated cost-effectiveness of a particular technology.

6. What changes, if any, does the Company recommend to the current regulatory framework to facilitate the cost-effective deployment of these technologies?

The Companies support the deployment of advanced technologies that enhance system reliability, resiliency, and clean energy integration. As part of regular needs assessments, Companies evaluate whether GETs and/or advanced conductors provide cost-effective solutions relative to traditional upgrades.

Investments on the network are situationally specific. In addition, as discussed above, GETs and advanced conductor technology is rapidly evolving. As a result, it is critical that ISO-NE and the relevant TO retains the discretion to identify and implement the best solution that balances affordability, reliability and sustainability. Given that GETs and advanced conductors are primarily focused on transmission, and Massachusetts transmission assets are part of the integrated New England regional network, the ISO-NE's transmission planning process is the appropriate venue for evaluating and proposing deployments of GETs and advanced conductors. The Companies support increased coordination between ISO-NE, the Massachusetts Department of Energy Resources, and transmission owners, to identify high-value opportunities for deployment of GETs and advanced conductors in the transmission network.

As referenced above, the Companies participated in and filed comments in the FERC docket related to the ANOPR on Implementation of Dynamic Line Ratings in Docket No. RM24-6-000. In those comments, the Companies expressed strong support for the goal of expanding transmission capacity through innovative technologies, advocated for a targeted and systematic approach to DLR deployment rather than a broad mandate, and emphasized that GETs should be implemented where GETs provides clear customer and grid benefits, following a thorough review of network constraints.

This proceeding may offer additional regulatory mechanisms to promote the adoption of cost-effective technologies through ISO-NE. Moreover, two recent major FERC orders require transmission providers to consider innovative technologies for certain types of transmission facilities: Order No. 2023,[5] which focuses on generation interconnection; and Order No. 1920,[6] which focuses on long-term regional transmission

[5] *Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, 184 FERC ¶ 61,054 (2023).
[6] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 (2024).

planning. The ongoing implementation of these two Orders through ISO-NE should create additional opportunities to deploy GETs and advanced conductors cost-effectively.

The Companies recommend that consideration of GETs and advanced conductors continue to be integrated into regional transmission planning processes, where cost-effective evaluations can be conducted transparently and inclusively.

IV. CONCLUSION

The Companies appreciate the opportunity to submit comments in response to the Department's request for comments on its investigation to examine the use of advanced conductors, grid-enhancing-technologies, and other advanced transmission technologies, and look forward to continued engagement on the issues the Department raised.

Date: July 3, 2025

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Investigation Into the Use of Advanced Conductors, Grid-Enhancing Technologies and Other Advanced Transmission Technologies to Enhance the Performance of the Commonwealth's Transmission System in Applications that are Subject to Federal Jurisdiction, Pursuant to St. 2024, c. 239, § 121.	)	D.P.U. 25-69

COMMENTS OF

NSTAR ELECTRIC COMPANY D/B/A EVERSOURCE ENERGY

I. INTRODUCTION

NSTAR Electric Company d/b/a Eversource Energy ("Eversource" or "Company") hereby submits the following comments in response to the questions and issues raised by the Department of Public Utilities (the "Department") in the June 2, 2025 Request for Comments and Vote and Order opening an investigation into the use of advanced conductors, grid-enhancing-technologies ("GETs"), and other advanced transmission technologies ("Request for Comments"). The Company addresses each of the Department's questions directed to the electric distribution and transmission companies in turn below.

II. RESPONSES

1. *Has the Company conducted any analysis or evaluation of advanced conductors, grid enhancing technologies (i.e., dynamic line readings, power flow controllers, topology optimization), or other advanced transmission technologies (generally, "technology" and "technologies") to deploy on its transmission or distribution grid?*

a. *Please describe each advanced transmission or distribution technology the Company has evaluated and summarize the main findings.*
b. *Provide a list of the transmission and distribution technologies that the Company considers mature, commercially available, and ready for integration into utility planning and grid operations.*

Eversource's responses to the Request for Comments mostly assume applicability of these technologies at transmission level voltages, which may have secondary benefits to the distribution system.

There are many advanced technologies Eversource is deploying on the distribution system that directly enhance distribution system performance, including those detailed in the Notice (i.e., (A) access to lower cost and zero carbon electricity; (B) acceleration of distributed energy resource interconnection; (C) reduced generator curtailment or congestion; (D) reduced environmental impacts; (E) maximization of the value of planned investments; (F) improved resilience; and (G) improved outage coordination and mitigation).

These distribution technologies include many that were supported by Department Grid Modernization and ESMP plans, such as Communications Modernization; SCADA/DMS; DERMS; VVO; Substation Automation; Resiliency; Microgrids; Flexible Interconnections; Outage Management and AMI. To the extent that the Department seeks additional information on the status of any of these deployments and/or the Company's roadmap for future distribution technology capabilities, the Company can provide such information upon request.

With that said, yes, over the past several decades, Eversource has analyzed and deployed numerous applications of advanced conductors, grid-enhancing technologies, and other advanced transmission technologies on its transmission and distribution systems in Massachusetts.

The evaluation of new technologies has been a standard step in the solution development stage of Eversource's FERC-approved Transmission System Planning process. For this reason, Eversource has had grid enhancing technologies in operation since the early 1980s.

a. Eversource's experience with each technology is described and summarized here:

- Dynamic Line Ratings - Eversource has had field deployments of dynamic line rating equipment since the early 2000s (e.g., near Norwalk Connecticut) and one project, that was awarded DOE GRIP funding, is in active construction in Southeastern Massachusetts. The ongoing project is targeting a 20-mile 345 kV transmission line between Canal and Carver Massachusetts. Using contactless DLR sensors, sag measurements will soon commence to initially train the machine learning model accuracy (i.e., first three months) and then almost two-years of data collection for line ratings. It is important to note, that Dynamic Line Ratings do not always increase line capacity. While some Eversource deployments have aided temporary emergency ratings for System Operations and/or asset health monitoring, permanent and significant increases in line capacity have not yet been observed. Also, some dynamic line rating sensors are incompatible with types of advanced conductors. Carbon core conductors can complicate the temperature monitoring approach utilized by some dynamic line ratings equipment/software.
- Ambient Adjusted Line Ratings (AARs) – Eversource is in the process of recalculating all of its transmission line ratings to be AARs and comply with FERC Order 881. Eversource is also updating its Energy Management System to employ AARs. The latest version of ISO-NE Planning Procedure 7 (available at https://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp07/pp7_final.pdf) shows that that some ambient temperatures are increasing, which means it is likely that transmission line ratings may decrease, resulting in less transmission capacity.
- Power Flow Controllers – Eversource has had Power Flow Controllers in operation since the early 1980s. Several ongoing projects, currently in engineering stage, are also proposing to install some of the world's largest power flow controllers. While redirecting flows on the transmission system can be effective at alleviating some thermal overloads that would otherwise need to be addressed, depending on the system topology and future changes in system flows, they can be a limited temporary solution since they do not provide any incremental addition transfer capability. Further, redirecting power flow to other lines can create cascading overloads that need to be addressed. For these reasons, detailed system studies must be completed on a case-by-case basis to ascertain the efficacy of Power Flow Controllers. Series power-electronic flow control devices operate physically differently compared to other power flow controllers and in some cases may not meet the need.

- Flexible Alternating Current Transmission System (FACTS) devices – Eversource has had decades of experience operating numerous FACTS devices, which are generally power electronics-based solutions for improving the controllability, stability, and/or power transfer capability of AC electrical grids (e.g., Static VAR Compensators (SVCs); Static Synchronous Compensators (STATCOMs). Notably, in June 2023, Eversource successfully commissioned and placed into service one of the world's first STATCOMs with Grid Forming capabilities. It is being used on the 132 MW South Fork Wind Offshore Wind Farm (developed through a joint venture with Ørsted), which is New York's first offshore wind farm. This technology provides numerous benefits, but was mainly driven by extremely weak grid conditions at its point-of-interconnection. In December 2023, South Fork Wind started producing power and it is expected to yield energy to supply the yearly average demand of 70,000 households and eliminate up to six million tons of carbon emissions each year, the equivalent of taking 60,000 cars off the road.

- Microgrids - In 2022, Eversource brought online the largest storage-only community Microgrid in the United States (per DOE Microgrid dataset). It is located in Provincetown Massachusetts and was a successful distribution Non-Wires and Non-Transmission Alternative comprised of a 25 MW/38 MWh BESS that has Grid Forming Capabilities. It serves approximately 10,000 electric customers and can operate fully islanded when normal grid connection is interrupted. The Provincetown BESS provides a new supply in Provincetown capable of carrying the entire radial line that serves the 13 mile area from the Wellfleet substation to Provincetown for various durations based on load level. The added microgrid controller and sub-minute auto-restoration capability reduces outage sizes and durations dramatically. The BESS and microgrid system address the reliability concerns that would have been solved by a traditional solution. The deployment of the Provincetown BESS avoided the construction of a second distribution line and has also allowed for the deferment of a second 115kV transmission line. The need for a new transmission line was driven by the forecasted increased system reliability in the area. Instead, a project which upgrades existing 4kV and 23kV circuits, adds new capacity to the Orleans and Eastham area, and relieves a major area circuit was implemented as an alternative approach. This new circuit permanently relieves enough load off the line that, in the event of the loss of transmission, the Provincetown BESS stored energy combined with the charging capacity of the upgraded circuits can carry all area distribution until the transmission line is restored.

- High-Temperature Low-Sag Conductors - Eversource has funded field installations of HTLS conductors for research purposes as far back as 2004. Eversource has also installed Aluminum Conductor Composite Reinforced (ACCR) conductors for certain projects to eliminate structure replacements in difficult construction locations. The ACCR conductor was developed by 3M corporation in the early 2000s with funding by the United States Department of Energy (DOE) to develop new technologies. In addition to adopting an advanced high-temperature low-sag conductor as its standard default conductor in 2021 that utilizes fully annealed aluminum and a high-emissivity coating, Eversource continues to monitor the development of HTLS technologies for use on the transmission system as these technologies continue to develop. These evaluations include material cost, installation practices, ampacity improvements, spare parts inventory, ancillary benefits, etc. Generally, Eversource's standard HTLS conductor increases line ratings by roughly 200-300 percent (i.e., increase varies between normal and emergency ratings), and this was demonstrated by a recent transmission reconductoring project in Southeastern Massachusetts.

- Clear Air Circuit Breakers - In December 2022, Eversource energized the first 115kV (kilovolt) clean air breaker in the United States as part of a suite of upgrades made to the Tunnel substation in Preston, Connecticut. Clean Air Circuit Breakers use purified oxygen instead of Sulfur hexafluoride (SF6), a potent greenhouse gas, as the insulating medium.
- High-Voltage Direct Current Transmission - In October 2021, Eversource and Ørsted (through a joint venture) selected Siemens Energy to supply a HVDC Transmission System for the 924-Megawatt Sunrise Wind Offshore Wind Farm, which is in construction and connecting into New York State on Long Island. Given that its submarine cable will stretch approximately 100 miles, utilizing HVDC technology offers numerous advantages over AC (e.g., reduced losses, no need for intermediate reactive support platforms, fewer cables, etc.). Sunrise Wind, one of the largest U.S. offshore wind farms, is located more than 30 miles east of Montauk Point and will generate enough clean energy to power nearly 600,000 New York homes.
- High-Temperature Superconductors – Eversource is preliminarily evaluating a phased project to interconnect three existing Eversource substations in a dense urban center with underground superconductor cables at the 13.8 kV distribution voltage level to create an additional layer of system redundancy and back-feed capability, resulting in improved grid reliability and resiliency which will ultimately allow for increased system capacity. This evaluation is in early-stage concept planning/studies.
- Networked Geothermal Heat Pumps – Eversource is piloting a networked geothermal heat pumps at scale in Framingham Massachusetts as a potential option to complement or replace delivered fuels and natural gas service for heating. The route is a neighborhood in Framingham consisting of 36 buildings – 24 residential and five commercial – for a total of 125 customer accounts. The technology may be expanded elsewhere based on the outcome of the pilot. To be clear, this technology was added to this list based on the inclusion of "reduced environmental impacts" in the Request for Comments.

b. The following is a partial list of technologies that Eversource considers mature, but a case-by-case analysis is required to determine the most efficient and cost-effective solution for each system need: Power Flow Controllers, Dynamic Line Ratings, Ambient Adjusted

Line Ratings, Flexible Alternating Current Transmission System (FACTS) devices, Advanced FACTS devices, Supercapacitors, Grid Forming Inverters, Synthetic Inertia, Distribution Management Systems (DMS), Distributed Energy Resource Management Systems (DERMS), High-Voltage Direct Current (HVDC) Technology, High-Temperature Low-Sag Conductors, Topology Optimization and Switching, Microgrids, Special Protection Schemes (SPS), Clean Air Breakers, High-Temperature Superconductors, and Tower Lifting.

2. *Has the Company conducted any cost benefit or total cost of ownership analyses for the technologies? If so, please provide the results and key assumptions used.*
   a. *Under what circumstances (e.g., load conditions, network congestion, geographic area) would these technologies be more cost effective than conventional transmission or distribution upgrades?*
   b. *Can these technologies help to avoid or delay the need for building new power lines or substations? Please explain your answer.*
   c. *Generally, do these technologies support Massachusetts climate goals and clean energy objectives?2 Please explain your answer.*
   d. *Has the Company identified any particular locations and/or opportunities in Massachusetts where the Company believes these technologies should be prioritized?*

No, Eversource has not conducted cost benefit or total cost of ownership analyses, unless such analyses were required for state siting proceedings.

a. Cost effectiveness varies too greatly by technology and project need to answer this question.

b. A case-by-case analysis is necessary to determine whether these technologies can help avoid or delay new power lines or substations. Each individual project has different drivers and needs. Further, building new power lines or substations to maintain system reliability and load service capabilities is constantly evolving. The extent to which these technologies are able to fully address such system needs varies by project. Also importantly, many of these technologies do not actually increase transmission capacity or load service capability, so they are incapable of deferring new lines or substations. With that said, Eversource's Provincetown Microgrid is one limited and unique example in Massachusetts that demonstrates the possibility exists for some of these technologies to potentially delay new lines.

c. Eversource believes that these technologies do support Massachusetts climate goals and clean energy objectives. The overarching objective of these technologies is to increase the utilization and/or effectiveness of the existing electric infrastructure. While GETs are an important component of the modernized electric grid, they are not a one-size-fits-all solution and must be carefully evaluated on a case-by-case basis. GETs should not generally be considered a substitute for the transmission infrastructure upgrades that are essential to connect a growing number of clean energy resources to the grid, supply enough power to meet the demands of electrification, and achieve state and regional decarbonization goals.

d. No, in general, Eversource has not identified specific locations to prioritize grid-enhancing technologies.

3. Has the Company conducted any pilots, demonstration projects, or feasibility studies for these technologies within Massachusetts or other jurisdictions? For each applicable project, please provide:

a. its geographic location;

b. a description of the project and related costs; and

c. a summary of the findings, outcomes, and lessons learned.

Please refer to the Company's response to subpart (a) of Question 1.

4. Are there quantifiable benefits to Massachusetts ratepayers from the implementation of these technologies? If yes, how does the Company determine and/or evaluate whether a specific technology is in the public interest?

Most quantifiable benefits would be highly dependent on the assumptions used in those calculations. Some of those assumption have regional differences that materially impact actual ratepayer benefits (e.g., design requirements like conductor ice loading or span lengths). Eversource's deployments thus far have been mostly driven by technical aspects like project need, engineering, feasibility, constructability, etc.

5. What are the primary barriers and/or implementation concerns that may prevent a wider adoption of such technologies?

Some barriers to wider adoption include lack of functional models from manufacturers to simulate technology performance and higher installed costs compared to alternatives.

6. *What changes, if any, does the Company recommend to the current regulatory framework to facilitate the cost-effective deployment of these technologies?*

Eversource does not believe there are any regulatory barriers to adopting grid-enhancing technologies.

III. CONCLUSION

Eversource appreciates the opportunity to provide comments on this important topic and looks forward to continued engagement on this matter with stakeholders and the Department.

Respectfully Submitted,
NSTAR ELECTRIC COMPANY d/b/a
EVERSOURCE ENERGY

By its attorneys,

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Date: July 3, 2025

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Investigation into the Use of Advanced Conductors, Grid-Enhancing Technologies and Other Advanced Transmission Technologies to Enhance the Performance of the Commonwealth's Transmission System in Applications that are Subject to Federal Jurisdiction, Pursuant to St. 2024, c. 239, § 121	)	D.P.U. 25-69

COMMENTS OF FITCHBURG GAS AND ELECTRIC LIGHT COMPANY d/b/a UNITIL

I. INTRODUCTION

Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil" or the "Company") appreciates the opportunity to provide the below comments in response to the Vote and Order Opening Investigation ("Order") issued by the Department of Public Utilities (the "Department") on June 2, 2025. The Company looks forward to working with the Department and interested stakeholders in this investigation.

II. COMMENTS

1. Has the Company conducted any analysis or evaluation of advanced conductors, grid-enhancing technologies (i.e., dynamic line readings, power flow controllers, topology optimization), or other advanced transmission technologies (generally, "technology" and "technologies") to deploy on its transmission or distribution grid?

The Company's system is predominantly distribution infrastructure. The Company owns and operates very little transmission infrastructure. Typically, this kind of technology is utilized at the transmission level, not at the distribution level. The Company's advanced distribution management system (ADMS) has the ability to automatically reconfigure its distribution system based on real-time loading conditions; however, the Company has not yet conducted an analysis of that functionality. With respect to dynamic line ratings, the Company is working with ISO-NE to implement the requirements from FERC Order 881 at the transmission level. The Company has not evaluated the implementation of dynamic line ratings at the distribution level.

a. Please describe each advanced transmission or distribution technology the Company has evaluated and summarize the main findings.

Please see the Company's response to question 1.

b. Provide a list of the transmission and distribution technologies that the Company considers mature, commercially available, and ready for integration into utility planning and grid operations.

Please see the Company's response to question 1.

2. Has the Company conducted any cost benefit or total cost of ownership analyses for the technologies? If so, please provide the results and key assumptions used.

No, the Company has not conducted any cost benefit or total cost of ownership analyses for grid-enhancing technologies at this time.

a. Under what circumstances (e.g., load conditions, network congestion, geographic area) would these technologies be more cost effective than conventional transmission or distribution upgrades?

The deployment of any technology will require a case specific analysis to compare alternatives; the Company cannot make broad assumptions about cost effectiveness. Location specific constraints, project costs and benefits are required to make prudent cost effectiveness comparisons.

b. Can these technologies help to avoid or delay the need for building new power lines or substations? Please explain your answer.

Please see the Company's response to (a) above.

c. Generally, do these technologies support Massachusetts climate goals and clean energy objectives? Please explain your answer.

Please see the Company's response to (a) above.

d. Has the Company identified any particular locations and/or opportunities in Massachusetts where the Company believes these technologies should be prioritized?

No, the Company has not.

3. Has the Company conducted any pilots, demonstration projects, or feasibility studies for these technologies within Massachusetts or other jurisdictions? For each applicable project, please provide:

a. its geographic location;

b. a description of the project and related costs; and

c. a summary of the findings, outcomes, and lessons learned.

The Company has not conducted any pilots, demonstration projects, or feasibility studies for these technologies within Massachusetts. Approximately ten years ago, the Company's regulated affiliate in New Hampshire, Unitil Energy Systems, Inc., did reconductor 35kV supply lines in the New Hampshire seacoast area with ACSS aluminum conductor steel supported (ACSS). At the time, and for this particular project, ACSS was deemed to be the least cost solution for the overloaded conductor.

4. Are there quantifiable benefits to Massachusetts ratepayers from the implementation of these technologies? If yes, how does the Company determine and/or evaluate whether a specific technology is in the public interest?

There potentially may be quantifiable benefits to Massachusetts ratepayers from implementing grid-enhancing technologies. Location specific constraints, project costs and benefits are required to make prudent cost effectiveness comparisons. As noted above, determining such benefits is fact-intensive and would require the Company to conduct a case-by-case analysis.

5. What are the primary barriers and/or implementation concerns that may prevent a wider adoption of such technologies?

Barriers and concerns that may prevent a wider adoption of such technologies include potentially higher initial implementation costs and the need for specialty equipment to make repairs to such technologies. As noted above, the deployment of any technology will require a case specific analysis to compare alternatives; the Company cannot make broad assumptions about cost effectiveness.

6. What changes, if any, does the Company recommend to the current regulatory framework to facilitate the cost-effective deployment of these technologies?

The Company does not recommend any specific changes at this time but looks forward to participating in and contributing to this docket as it proceeds, and reserves the right to comment on any regulatory changes discussed.

III. CONCLUSION

Unitil appreciates the opportunity to provide comments in response to the Department's Order and looks forward to working collaboratively with the Department and other stakeholders in this docket.

[SIGNATURE BLOCK ON NEXT PAGE]

Dated: July 3, 2025

Respectfully submitted,

Fitchburg Gas and Electric Light Company d/b/a Unitil

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COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Investigation Into the Use of Advanced Conductors, Grid-Enhancing Technologies and Other Advanced Transmission Technologies to Enhance the Performance of the Commonwealth's Transmission System in Applications that are Subject to Federal Jurisdiction, Pursuant to St. 2024, c. 239, § 121.

D.P.U. 25-69

INITIAL COMMENTS OF LINEVISION INC. ON VOTE AND ORDER OPENING INVESTIGATION

July 3, 2025

A. Executive Summary

On June 2, 2025, the Commonwealth of Massachusetts Department of Public Utilities (DPU or Department) opened its investigation into the use of advanced conductors, grid-enhancing technologies (GETs), and other advanced transmission technologies. Section 121 of St. 2024, c. 239 (the 2024 Climate Act) requires the DPU to conduct this investigation to enhance the performance of the commonwealth's transmission system. In its investigation, the DPU is required to review industry trends related to these technologies, determine which are cost-effective and in the public interest and under what conditions they could be utilized in transmission and distribution infrastructure. For any technologies determined to be cost-effective and in the public interest, the DPU must identify jurisdictional and cost-sharing issues related to any requirements to implement such technologies, considering their costs and benefits. The DPU's report to the joint committee on telecommunications, utilities, and energy is due September 1, 2025.

LineVision, Inc. (LineVision) is pleased to submit these comments in response to the various questions set forth in the docket. LineVision is a Boston-based GETs company that provides electric utilities with monitoring solutions for high-voltage transmission lines that can unlock as much as 40% additional capacity on existing lines through Dynamic Line Ratings (DLR). LineVision's non-contact sensors and sophisticated analytics also enable actionable insights into the real-time status and long-term health of transmission lines while improving situational awareness, helping to ensure their optimal, safe, and reliable operation.

B. DLR Has Been Deployed Widely Across the World and is Ready for Scale in Massachusetts

Historically, transmission owners have utilized static or seasonal ratings to determine a transmission line's rating, which reflects the amount of capacity a line can safely pass through. A static rating assumes that all of the conditions that impact the temperature of a line are fixed. Once a transmission owner monitors the line, they can see what conditions actually exist, allowing them to move the appropriate amount of power, which is consistently more than static ratings currently allow. Some transmission owners have moved towards using Ambient Adjusted Ratings (AAR), which modifies static ratings based on ambient conditions like outside air temperature. Dynamic line ratings, or DLR, however, go one step further in that they measure wind conditions in addition to ambient conditions. Wind is by far the biggest variable in how a line's rating changes; incorporating the wind variable into a line's rating can often increase transmission capacity 30-40%.[1] Historically, transmission owners have utilized conservative assumptions to rate their lines.

[1] U.S. Department of Energy (DOE), Dynamic Line Ratings Systems for Transmission Lines, Topical Report (April 2014): https://www.energy.gov/sites/prod/files/2016/10/f34/SGDP_Transmission_DLR_Topical_Report_04- 25-14.pdf

With DLR, transmission owners have access to the data needed to understand the real-time status and health of their lines, which includes utilities realizing excess capacity over 90% of the time.[2] The Federal Energy Regulatory Commission (FERC) has found that the benefits of more accurate transmission line ratings outweigh the cost to implement DLR.[3]

The concept of DLR is relatively simple. The cooler a line, the more power it can move. While the concept of DLR has long been understood, two paradigm shifts have precipitated its advancement over the last decade. First, data science has unlocked deeper capabilities to understand the hyper-local conditions that can cool lines. And second, the need for DLR has become far more pronounced, with load growth and changes to the electric generation mix driving transmission owners to deliver ever increasing amounts of power. Utilities in Massachusetts also have experience with the technology. For example, National Grid's Massachusetts deployment of DLR added an average increase of 47% in line capacity.[4]

It is clear that GETs like DLR are cost-effective for a number of use cases, including alleviating congestion, improving reliability and resilience, and increasing the speed with which utilities can connect new load and generation. Put simply, DLR allows utilities to get the most out of what exists today while also looking to plan and build new infrastructure, as when DLR is not sufficient to solve entire grid needs, it can be paired with new transmission to improve the cost-effectiveness and increase the utilization of these long-term investments. We recommend that the Department move quickly to establish requirements or incentives that ensure the electric distribution companies (EDCs) are utilizing their system as efficiently as possible by deploying GETs like DLR where they will be cost-effective investments for ratepayers.

In Section C, we respond to several of the Department's questions.

C. LineVision's Responses to the Department

1. *Please describe any advanced transmission or distribution technologies your company offers.*
    a. *What is the current technology readiness level of your product(s)?*
    b. *Is/are the product(s) commercially available?*

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[2] Unlock Power Line by Line: Dynamic Line Ratings. WATT Coalition: https://watt-transmission.org/wp-content/uploads/2024/11/Unlocking-Power-Line-by-Line-Dynamic-Line-Ratings.pdf

[3] Docket No. RM24-6-000, Implementation of Dynamic Line Ratings (June 27, 2024) (ANOPR), ¶ 54.

[4] K. Engel et al. "An Empirical Analysis of the Operational Efficiencies and Risks Associated with Static, Ambient Adjusted, and Dynamic Line Rating Methodologies," CIGRE-US National Committee, 2021 Next Generation Network Paper Competition, (July 2021): https://cigre-usnc.org/wp-content/uploads/2021/11/An-Empirical-Analysis-of-the-Operational-Efficiencies-and-Risks-Associated-with-Line-Rating-Methodologies.pdf

LineVision is the leading US provider of DLR - grid monitoring solutions that help utilities rapidly unlock transmission capacity, enhance grid resilience, and meet the demands of the new energy economy. LineVision's patented non-contact sensors collect critical information to unlock additional capacity on existing lines, provide insight on conductor health, and detect anomalies and risks, including conditions that can lead to wildfires.

LineVision's DLR utilizes sensors to monitor the ambient weather conditions that heat or cool transmission lines to continually calculate their true capacity, which can allow significantly more power flow than a static or ambient adjusted rating. Deploying DLR has helped utilities integrate large loads such as factories and data centers, reduce congestion for additional generating resource integration, and bolster system reliability around the world.

LineVision's solution is commercially available and deployed in other US states and countries. We currently work with seven of the 10 largest utilities in the US, including a fully operationalized deployment with National Grid in New York, where data is being provided to New York Independent System Operator (NYISO). LineVision's DLR offering is a technology readiness level (TRL) of 9.

2. *Please describe the primary cost categories and amounts associated with your product(s).*
    a. *What are the typical installation costs for your technology (per mile, per site, per kilowatt/megawatt, or as applicable)?*
    b. *What are the expected operations and maintenance costs over the technology's useful life?*
    c. *What factors most strongly affect the cost effectiveness of your technology?*

As demonstrated in transmission owner AES's recent case study utilizing LineVision's DLR technology, our solution costs $45,000 per mile on average, which is inclusive of 20 years of software costs.[5] That is roughly $2,000 per year, per mile - orders of magnitude cheaper than traditional solutions.

The primary cost categories of our DLR solution typically include sensor purchases (hardware), annual server, communications, and ratings update costs (software), and then installation costs for sensors (labor). The useful life of LineVision's hardware is at least 10 years on average. There are no regular maintenance costs, and onboard diagnostics report on device health.

The cost-effectiveness of DLR is largely determined by the use case it is solving for. For example, DLR has proven to be a highly cost-effective tool in addressing congestion, where PPL Utilities in Pennsylvania deployed a $250,000 investment in DLR that avoided $23 million in congestion costs for just a single year. On another PPL line, DLR reduced congestion from around $66 million in the winter of 2021-22 to just $1.6 million the following winter.[6] DLR is also cost-effective in that it more quickly allows the integration of new generation and load onto the grid in months, foregoing the need to wait years or decades to build new transmission, allowing Massachusetts to

[5] Lessons from first deployment of dynamic line ratings, AES: https://www.aes.com/sites/aes.com/files/2024-04/AES-LineVision-Case-Study-2024.pdf
[6] Comments of PPL Electric Utilities, AD22-5, FERC, February 9, 2024: https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20240209-5161

better meet its policy goals and ensuring economic development opportunities stay in the Commonwealth. These represent just two examples of cost-effective uses of DLR, with additional use cases discussed in greater detail below.

While DLR costs alone may be informative, they are much more useful when compared against alternatives, and also compared against benefits. With regard to alternatives, as mentioned above, DLR can act as an alternative to new transmission infrastructure, re-building lines, or re-conductoring lines. For example, in the same case study referenced above, AES compares the cost and time for a 20-year DLR project against a re-conductored asset. As noted in that AES case study, to deliver over 50% in capacity gains, DLR cost $45k per mile, whereas re-conductoring would have cost $590k per mile - about 13 times the cost. Further, DLR would take 9 months to fully operationalize, while re-conductoring would take 2 years. Lastly, deploying LineVision's DLR would incur no outage, while re-conductoring would result in 1 week of outages per mile. This study demonstrates just one example of where DLR is cost-effective when compared against alternatives. When seeking to deploy new transmission investments, the EDCs should always fully evaluate (including costs and benefits, as well as alternatives) the ability of DLR to meet an identified grid need, either on its own, in conjunction with other GETs, or paired with new transmission.

It is important to note that DLR does not present an "either/or" scenario where choices need to be made between traditional means of building grid capacity or even between other GETs. An "all of the above" standard can be used where multiple technologies can be deployed on different time horizons to meet the challenges the grid is facing while managing affordability for customers. Whenever a cost-effectiveness evaluation of DLR is being conducted, it should consider all benefits and costs. Initial capital costs, as well as any ongoing O&M and software costs should be factored into the cost part of the equation. LineVision has observed that many utilities rely on cost estimates for previous DLR projects undertaken years ago or at a small scale, which are not necessarily reflective of current or future costs.

To calculate benefits - for the purpose of the Department's report and cost-effectiveness analysis, and for future EDC evaluation of GETs - benefits evaluated should, at a minimum, include all seven benefits listed in the 2024 Climate Act, which includes 1) access to lower cost and zero carbon electricity; 2) acceleration of distributed energy resource (DER) interconnection; 3) reduced generator curtailment or congestion; 4) reduced environmental impacts; 5) maximization of the value of planned investments; 6) improved resilience; and 7) improved outage coordination and mitigation. There are, however, additional benefits that should be captured in future cost-benefit analyses related to GETs.

According to a separate analysis performed by The Brattle Group that evaluated the ability of DLR, other GETs, and high performance conductors (collectively "advanced transmission technologies" or ATTs) to meet the objectives defined in FERC's landmark Order 1920, ATTs can collectively provide each of the seven benefits defined in the Order.[7] The report includes an in-depth analysis of 25 case studies on ATTs, tying each FERC-identified benefit to a specific ATT technology and use case. Among the seven benefits identified by FERC, DLR was determined to meet four: 1) avoided or deferred reliability transmission facilities and aging infrastructure replacement (benefit 1); 2) reduced loss of load probability or reduced capital costs to meet planning reserve margin (benefit 2); 3) production cost savings (benefit 3); and 4) mitigation of extreme weather events and unexpected system conditions (benefit 6). These calculatable benefits should be factored into the Department's and future EDCs' cost-effectiveness analysis of DLR, and all seven benefits may warrant inclusion in future comprehensive analyses of GETs or ATTs.

3. *Please describe the primary benefits associated with your product(s).*
    a. *What are the technical, operational, and commercial benefits of your technology?*
    b. *Does your technology support broader public policy goals including, but not limited to, the integration of clean energy, emissions reductions, grid resilience, or cost savings for customers and ratepayers?*

Generally, LineVision categorizes the benefits our solution provides into the following categories:

1) **Affordability:** DLR often costs 5% or less of the cost utilities would otherwise incur for re-conductoring a line or building new transmission.[8] With Massachusetts' rapidly aging infrastructure, increasing load growth, and lengthy interconnection queue, transmission capacity is urgently needed. DLR addresses affordability pressures by efficiently optimizing existing infrastructure, before the need to build new, more time- and cost-intensive investments. Deploying DLR can lead to the deferral or avoidance of grid investments in certain cases.
2) **Reliability:** The vast majority of transmission lines in the US are unmonitored today and many of these lines are also approaching the end of their useful life. Our sensors provide a precise measurement of transmission line health, giving utilities real-time data regarding how much power can safely pass through a line during any given segment of time. Utilities that use DLR have increased operational flexibility to move more power on parallel circuits when parts of the grid are down due to storm damage or scheduled maintenance. Our solution provides precise wind measurements and forecasting within transmission right-of-ways, providing utilities with additional situational awareness capabilities to better assess risk during severe weather events.
3) **Efficiency:** Deploying DLR can quickly get more capacity out of the existing grid, allowing utilities to much more quickly connect new or expanded loads and new generation. In the era of high load growth, deploying DLR would support economic development in the Commonwealth, by adding the grid capacity needed to welcome new manufacturing, electrification, and data center load quickly.

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[7] Incorporating GETs and HPCs into Transmission Planning Under FERC Order 1920; The Brattle Group, April 2025: https://acore.org/wp-content/uploads/2025/04/Report__Incorporating-GETs-and-HPCs-Under-FERC-Order-1920__April-21-2025.pdf
[8] Comments of the WATT Coalition et al., FERC AD-22-5-000, April 25, 2022: https://watt-transmission.org/wp-content/uploads/2022/04/DLR-NOI-Comments-WATT-ACP-AEE-SEIA.pdf

As utilities build transmission, DLR can provide congestion relief benefits and outage mitigation benefits before, during, and after the construction of transmission upgrades. In this new era of load growth - and in particular, one in which load growth is highly uncertain, DLR can act as a bridge tool by increasing the grid's capacity in the immediate term, while new transmission is built over the long term.[9] It typically takes 7-10 years to build new transmission, so low-cost DLR can be deployed where transmission capacity shortfalls are expected, allowing utilities to interconnect more load and generation in the near-term, while building larger scale transmission over the longer term. Acting as a bridge solution will allow generation and load projects to proceed while construction of longer-term transmission investments are underway. Further, DLR can mitigate the need for the service interruptions that are needed to perform reconductoring, rebuilding, or building new lines.

DLR directly supports and ties closely with the Commonwealth's broader public policy goals, as well as the seven benefits listed in the 2024 Climate Act: 1) access to lower cost and zero carbon electricity; 2) acceleration of distributed energy resource (DER) interconnection; 3) reduced generator curtailment or congestion; 4) reduced environmental impacts; 5) maximization of the value of planned investments; 6) improved resilience; and 7) improved outage coordination and mitigation.

One of the primary use cases for DLR is to quickly expand the capacity of the transmission grid. Adding to the grid's capacity will alleviate congestion, allowing existing low-cost electricity to flow to load customers. DLR is fuel-agnostic, so with added grid capacity, projects that have been idle in the interconnection queue for years will have the needed grid capacity to connect. Reduced congestion can also alleviate grid constraints at peak hours, reducing the need to curtail the lowest cost, and often cleanest, energy in lieu of expensive and higher-emitting generators, improving regional and localized environmental impacts. As noted above, while utilities can often take 10 years to build new transmission projects, DLR can add capacity to the grid quickly, allowing utilities to more strategically right-size planned investments and identify opportunities to defer or avoid others. Then when deployed during construction of new transmission, DLR can help to get the most out of parallel/contingent lines, reducing the need to conduct outages.

4. *Does your technology integrate with existing grid infrastructure and utility operation systems?*
    a. *Are there unique requirements required to operationalize your technology (e.g., siting and permitting, workforce training, operability with utility systems, etc.)?*
    b. *What is the typical deployment timeline for your solution from planning to operation?*

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[9] Consumer advocates have urged FERC to re-consider how it looks at load forecasts, noting that utility load forecasts are almost always higher than what actually materializes, which can result in the unnecessary buildout of new infrastructure to accommodate non-existent load, stranding potentially expensive investments: https://www.utilitydive.com/news/electricity-consumer-groups-ferc-load-forecasts-data-centers/749754/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202025-06-04%20Utility%20Dive%20Newsletter%20%5Bissue:73759%5D&utm_term=Utility%20Dive

c. *Do you offer support or training for utilities to assist with the deployment and operation of your technology?*

Yes, LineVision's technology integrates with existing grid infrastructure and utility operations systems. We have a fully operationalized deployment with National Grid's affiliate in New York, where DLR data is being provided to the grid operator, NYISO, as well as a separate operationalized project with National Grid in the United Kingdom. A combination of transmission tower-mounted sensors and software is used to generate ratings data, and this data is incorporated into the utility's control room EMS for use in operations.

The typical deployment timeline from planning to operations is approximately nine months, but this can vary depending on how quickly the utility proceeds. A LineVision Client Engagement Manager works directly with each utility throughout the contract lifecycle to provide project management oversight, training of utility personnel, and ensure the desired outcomes of the utility are achieved.

The LineVision process begins with line selection; target lines are identified based on needs related to load growth, congestion, outage mitigation, or other customer-identified challenges. Once lines are identified, a detailed scoping process takes place using Computational Fluid Dynamics (CFD) modeling to identify the precise number and location of sensors required to deliver a safe DLR. No siting or permitting is required for any site, and discretion can be applied where necessary to avoid locations that may present access challenges or require environmental review. Once the scope is finalized, the install is scheduled in coordination with the utility.

The sensor installation process is straightforward and can be completed using standard hand tools. No live line work or outages are required, as the hardware is mounted on the towers, rather than directly on lines, meaning that the installations can be scheduled independent of any operational considerations. The installation itself is completed by the utility's line crew, with direction from a LineVision Field Operations Manager. Typically, 4-6 sensors can be installed each day, so even large installations are completed within 1-2 weeks.

Upon completion of the installation, there is a 30 to 60 day model training period wherein sensor data is used to train and validate a CFD model. This model takes localized weather data as an input and calculates DLR as an output. The DLR is then made available on an online data portal for review by the utility.

In parallel to the above DLR enablement process, LineVision works with the utility on the operationalization process. The utility may elect a cloud-based API integration or an on-premise integration. In either case, the goal is to incorporate hourly DLR data into the control room EMS for use in grid operations. LineVision has developed integration architectures that are broadly applicable and designed to adhere to typical utility requirements, such as NERC CIP standards.

While LineVision's integration architecture is broadly applicable, each utility has a unique current-state architecture and cybersecurity requirements. As such, LineVision works in collaboration with relevant teams within the utility including IT, Cybersecurity, and Operations to develop a specific, detailed integration design. The integration is built and tested, typically in a development or QA environment. Control room operators are provided with training to understand the use of DLR and how to incorporate it into existing workflows. The data flow with the ISO is also established such that DLR can be shared with the system operator.

When ready, the final step is "go-live" in the utility's production environment, when the ratings can be used by the Operations team. In all, from the beginning of project identification to installation and full-on operationalization, the timeline takes approximately nine months. Even after operationalization, LineVision continues to monitor sensor data and provide model updates on a periodic basis to ensure the model reflects the latest changes in the field.

5. *Where have your technologies been deployed to date?*
    a. *Are there specific examples where your solution was deemed to be more cost effective than a traditional grid upgrade?*
    b. *Are there specific types of projects or system conditions where your technology is particularly valuable?*
    c. *Was the deployment subsidized by any government entities or others? If so, how important was this support to deployment?*

LineVision's technology has been deployed at over 500 sites across 4 continents, including projects with seven of the 10 largest utilities in the US. Across all of our projects, we have identified an average of 36% in capacity gains.

LineVision's DLR has indeed been determined to be a more cost-effective investment over other transmission upgrades in certain circumstances. For example, utility AES compared the cost, time, and capacity gains of a 20-year DLR project versus a reconductored asset, as shown below:[10]

Table 4. Comparison of cost and time for a 20-year DLR project versus reconductored asset

Measure	DLR	Reconductoring
Average Capacity Delivered	>50%	50%
Cost	$45K per mile[12]	$590K per mile[13]
Time to Operational	9 months	2 years
Outage required	None	1 week per mile[14]

DLR was shown to be 13 times more cost-effective than reconductoring in this example. On another AES line, where the utility had planned to undertake a larger grid upgrade project, deploying DLR allowed AES to realize that the constraint on the line was limited to a half-mile segment. The data provided through LineVision's DLR deployment meant AES could take a more targeted approach by only re-conducturing that smaller segment of the line, which would allow

[10] Lessons from first deployment of dynamic line ratings, AES, at 14: https://www.aes.com/sites/aes.com/files/2024-04/AES-LineVision-Case-Study-2024.pdf

AES to build the upgrade in half the time and at a quarter of the cost of a full reconductoring project. According to AES, "[i]f a load growth, reliability, congestion, or similarly beneficial narrative supports the comparatively modest investment in DLR technology, these types of lines present a use case for rapid scaling for the U.S. electrical grid. Indeed, when compared to traditional solutions to increasing carrying capacity, DLR is a powerful option."[11]

Furthermore, as noted by The Brattle Group, "GETs are also highly complementary to transmission expansion through new lines. They can magnify the cost effectiveness and capabilities provided by new transmission investments. They provide short-term solutions to temporary operational challenges, such as during transmission outages or the construction of new lines, and bridge gaps until permanent expansion solutions can be put in place. They also are realistic alternatives for long-term solutions, particularly where building transmission makes less economic sense."[12]

Effectuating technology adoption by utilities typically requires mandates, incentives, and signals. Some of LineVision's projects have been supported through government subsidies, including through programs at the Department of Energy (DOE). While federal funding was certainly helpful in creating the interest to undertake DLR projects at some utilities, LineVision has deployed many projects where utilities deemed an investment in DLR to be cost-effective without government subsidy. And as demonstrated through the various studies and reports mentioned above, DLR projects are often cost-effective on their own merits, without requiring subsidy to enable cost-effectiveness.

6. *What, if any, adoption barriers has your company encountered?*
    a. *Are there specific barriers that currently limit the use of your technology in Massachusetts relative to other jurisdictions?*
    b. *Please describe your experience in working with utilities or government entities in Massachusetts and/or other jurisdictions.*
    c. *Do you have any recommendations or considerations on how to facilitate cost-effective and timely adoption of advanced grid technologies?*

In regards to facilitating greater adoption of GETs, the Department has several tools at its disposal to create requirements or incentives. In terms of a pathway to increased adoption, about a dozen other states have instituted legislative requirements in the last two years that require utilities to incorporate an evaluation of GETs into standing planning processes - either resource planning, or investment planning (e.g., rate cases, transmission plans, and other capital expenditure proceedings). Utilities also require a clear path to cost recovery for these investments, where fair and reasonable treatment is required for the software costs associated with deploying DLR. This could be achieved through changes to which expenditures are eligible to receive a return on equity

[11] *Id.*

[12] Building a Better Grid: How GETs Complement Transmission Buildouts; The Brattle Group, April 20, 2023: https://www.brattle.com/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf

(ROE), or which investments can be capitalized and treated similarly to other regulatory assets (i.e., depreciable).

Historically, utilities have not been required to optimize the grid's efficiency. However, with ever-rising costs and a clear need to build out new grid infrastructure, optimization of existing assets is more important now than ever. To help optimize the grid, the Department could consider instituting a "loading order" approach, whereby optimization is considered first, prior to new investment. An efficient approach to capacity expansion could require EDCs to consider the below options in order:

1) First consider methods of optimizing the grid, by deploying tools like GETs on existing assets to maximize their capacity;
2) If that does not realize sufficient capacity, then consider methods to strengthen the grid, like through re-conductoring or rebuilding lines; and
3) If that does not realize sufficient capacity, expand the grid by constructing new transmission lines and rights-of-way.

The Department has the opportunity to implement changes to the regulatory paradigm in the Commonwealth that could truly spur the scaled adoption of GETs, leading to near-term ratepayers savings.

With respect to Massachusetts in particular, there are no particular barriers preventing more widespread and scaled adoption of DLR in the Commonwealth - in fact, there are a number of reasons why Massachusetts is well-suited to become a leader in DLR.

First, the Massachusetts EDCs are well-versed in evaluating and deploying GETs, including DLR in particular. As noted above, LineVision's DLR is fully operationalized with two of National Grid's affiliates - in New York and in the UK. Further, Eversource, in collaboration with the University of Connecticut, received a grant to deploy DLR on transmission lines to deliver additional generation into the region.[13]

More so, with the Department's focus on proactive system planning and grid modernization (i.e., through the Capital Investment Plan (CIP) dockets and Electric System Modernization Plans), there is a clear understanding of the need for more proactive system planning and the ability to right-size investments to add headroom. DLR allows utilities to do just that, but at a significantly lower cost as compared to traditional transmission investments or even re-conductoring.

There are several opportunities for the Department to take action to facilitate the cost-effective and timely adoption of GETs technologies. In addition to considering the loading order approach that was highlighted by the Clean Energy Transmission Working Group (CETWG),[14] the Department could:

[13] https://www.energy.gov/oe/grid-enhancing-technologies-improve-existing-power-lines
[14] https://www.mass.gov/doc/clean-energy-transmission-working-group-final-report/download

1. Require a congestion analysis that identifies where GETs can be deployed to cost-effectively relieve congestion, and direct the EDCs to deploy GETs where the benefit would outweigh the cost.
2. Direct the EDCs to model and evaluate the cost-effectiveness of GETs in the various resource or investment planning proceedings they are involved in, such as in Integrated Resource Plans, or any dockets in which the EDCs are proposing capital upgrades on the transmission system. Within those analyses, GETs should be evaluated both as standalone solutions to meet grid needs, and as complementary investments that improve the cost-effectiveness of new transmission by adding more headroom at low cost.
3. Consider the use of incentives, such as performance incentive mechanisms (PIMs) to encourage the adoption of GETs. For example, the UK has utilized a shared savings mechanism that ensures utilities only receive an incentive if ratepayers realize savings from the utility's reduction of congestion through its deployment of GETs.[15]

The Department could enact these potential changes to the regulatory framework through this investigation and spur near-term action that will improve the reliability, affordability, and efficiency of the grid.

D. Conclusion

We appreciate the Department providing the opportunity to submit comments to inform the investigation, and ultimately, report to the legislature. The majority of DLR deployments in the U.S. to date have been at pilot scale only, but have clearly demonstrated significant cost savings and efficiency gains. Massachusetts has the opportunity to become a leader on DLR by scaling the technology and associated benefits more broadly than other states yet have, and the timing is right for the Department to incent or require the use of DLR as a key tool to optimize existing infrastructure, improve the reliability of the grid, and create significant savings to ratepayers. Thank you for considering these comments.

Respectfully submitted,

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[15] National Grid in the UK highlights the incentive developed under the regulatory framework, RIIO-T2, that rewards the utility for helping the system operator to minimize constraint payments: https://www.nationalgrid.com/electricity-transmission/who-we-are/riio-t2-performance#230548828-3345694417

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Topolonet LineID™ – Responses to Massachusetts D.P.U. 25-69 Stakeholder Questions (Docket D.P.U. 25-69)

1. **Please describe any advanced transmission or distribution technologies your company offers.**
   a. **What is the current technology readiness level of your product(s)?**
   b. **Is/are the product(s) commercially available?**

LineID™ is a software-only dynamic line-rating (DLR) platform that runs on utility-owned servers and ingests existing time-synchronized phasor (PMU) streams from both ends of a circuit to compute, in real time, the line's average conductor temperature, rating, and full electrical parameters without additional sensors or weather inputs. A companion module, LineID-Spans™, can incorporate coarse weather data to derive span-by-span temperatures.

a. Technology readiness level: Laboratory validation is complete and utility field pilots are in progress (TRL 6–7).
b. Commercial status: LineID™ is available today for pilot deployments under early-access agreements and will transition to full commercial release after the current pilots conclude.

2. **Please describe the primary cost categories and amounts associated with your product(s).**
   a. **What are the typical installation costs for your technology (per mile, per site, per kilowatt/megawatt, or as applicable)?**
   b. **What are the expected operations and maintenance costs over the technology's useful life?**
   c. **What factors most strongly affect the cost effectiveness of your technology?**

Primary cost categories: (1) perpetual or term software license, (2) one-time system integration and commissioning services, (3) optional annual support and update subscription. There are no sensor, construction, or field-maintenance costs.

a. Installation costs are dominated by software deployment and integration effort because no per-mile hardware is required.
b. Operations and maintenance costs are limited to periodic software upgrades and optional support, normally a small fraction of the initial license fee; there is no field O&M.

c. Cost-effectiveness is driven by the availability and quality of PMU data, the congestion value of incremental capacity, and the avoided capital cost of alternatives such as reconductoring or sensor-based DLR.

3. **Please describe the primary benefits associated with your product(s).**
   a. **What are the technical, operational, and commercial benefits of your technology?**
   b. **Does your technology support broader public policy goals including, but not limited to, the integration of clean energy, emissions reductions, grid resilience, or cost savings for customers and ratepayers?**

Technical benefits: ≤ 1-min refresh of dynamic ratings; ability to detect icing, galloping, and high-resistance joints through changes in calculated electrical parameters; no new field hardware improves safety and reduces cyber-attack surface.

Operational benefits: Unlocks 5–30 % latent capacity on congested corridors, improves situational awareness for operators, and enhances state-estimator accuracy.

Commercial/public-policy benefits: Defers or avoids costly reconductoring, expedites renewable integration by reducing curtailment, and supports Massachusetts decarbonization targets, while protecting ratepayers by leveraging existing grid assets and increasing the capacity of the grid.

4. **Does your technology integrate with existing grid infrastructure and utility operation systems?**
   a. **Are there unique requirements required to operationalize your technology (e.g., siting and permitting, workforce training, operability with utility systems, etc.)?**
   b. **What is the typical deployment timeline for your solution from planning to operation?**
   c. **Do you offer support or training for utilities to assist with the deployment and operation of your technology?**

LineID™ ingests IEEE C37.118 PMU streams and can exchange ratings with any available infrastructure.

a. **Unique requirements:** Access to synchronized three-phase voltage and current phasors from both ends of the circuit and a server (physical or virtual) inside the utility's secure network. Operator training is minimal.
b. **Deployment timeline:** When PMU streams are available, installation, configuration, and acceptance testing can be completed in less than one month.
c. **Support/training:** Topolonet provides installation assistance, on-site or virtual training, and ongoing technical support for the duration of the pilot or license.

5. **Where have your technologies been deployed to date?**
   a. **Are there specific examples where your solution was deemed to be more cost effective than a traditional grid upgrade?**

b. **Are there specific types of projects or system conditions where your technology is particularly valuable?**
c. **Was the deployment subsidized by any government entities or others? If so, how important was this support to deployment?**

LineID™ is currently in pilot deployment with two U.S. utilities (names confidential) and Pacific Northwest National Laboratory on 345 kV corridors. It has been independently evaluated by Pacific Northwest National Laboratory.

a. LineID™ is currently in active pilot testing; quantitative performance metrics will be released after data collection and validation are complete.
b. The solution is especially valuable on lines that already have PMUs, where terrain makes sensor installation costly, or where rapid capacity increases are required.
c. Current pilots are funded by utility R&D budgets; no external subsidies have been necessary.

6. **What, if any, adoption barriers has your company encountered?**
   a. **Are there specific barriers that currently limit the use of your technology in Massachusetts relative to other jurisdictions?**
   b. **Please describe your experience in working with utilities or government entities in Massachusetts and/or other jurisdictions.**
   c. **Do you have any recommendations or considerations on how to facilitate cost-effective and timely adoption of advanced grid technologies?**

Adoption barriers: Limited PMU coverage on some circuits; conservative operational culture; the need for regulatory acceptance of software-only DLR using PMU data; and IT/cyber-security onboarding processes.

a. Massachusetts-specific barriers may include ISO-NE acceptance of real-time software-only ratings and variable PMU availability across the Commonwealth.
b. Topolonet has participated in Northeast utility workshops and engaged with state agencies, but no Massachusetts pilot has yet been executed.
c. **Recommendations:** Expand PMU deployment, streamline IT onboarding for on-premise analytics, clarify cost-recovery for software DLR in DPU proceedings, and incorporate DLR in ISO-NE operational frameworks.

Respectfully Submitted,

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Comments of NewGrid, Inc. to the Commonwealth of Massachusetts Department of Public Utilities, in response to questions from June 2, 2025 Investigation on Grid-Enhancing Technologies

D.P.U. 25-69

Submitted July 3, 2025

Introduction

NewGrid, Inc. (NewGrid) is pleased to submit these written responses to Massachusetts Department of Public Utilities ("DPU"), addressing questions raised in the investigation on Grid Enhancing Technology ("GETs").

NewGrid is a transmission topology optimization technology company. NewGrid was incorporated in 2015, as a spin-off of a research and development project led by Boston University and other Massachusetts organizations, partially funded by the DOE ARPA-E and the MassCEC. NewGrid is headquartered in Somerville, MA.

These responses are a complement to those submitted by the WATT Coalition, of which NewGrid is a member, and whose comments NewGrid supports.

Specific Questions

C.1 Please describe any advanced transmission or distribution technologies your company offers.

> *a. What is the current technology readiness level of your product(s)?*
>
> *b. Is/are the product(s) commercially available?*

NewGrid offers topology optimization software and services. Our software package, NewGrid Router, is like a "GPS app for the grid," in that it can quickly and systematically identify and evaluate options to re-route power flow over the transmission network. The re-routing is achieved by reconfiguring the existing grid: opening or closing existing circuit breakers.

NewGrid Router has been designed to be an offline engineering decision support tool, and it has a technology readiness level (TRL) of 9. It is commercially available.

C.2. Please describe the primary cost categories and amounts associated with your product(s).

> *a. What are the typical installation costs for your technology (per mile, per site, per kilowatt/megawatt, or as applicable)?*
>
> *b. What are the expected operations and maintenance costs over the technology's useful life?*
>
> *c. What factors most strongly affect the cost effectiveness of your technology?*

NewGrid Router is a software package that can perform system wide topology optimization functions. A single installation, for example at a utility or Regional Transmission Organization (RTO) site, can search for reconfiguration options to mitigate constraints anywhere in the system.

As with other software packages used in the transmission utility industry for decision support, the adoption costs involved are the cost of the licenses, the cost of servers on which the software runs, costs for maintenance and support, and staff time (including training). The order of magnitude of these costs for the adoption of NewGrid Router costs are similar to those of other decision support software packages used by utilities for other functions. Compared to the costs of transmission upgrades or extreme congestion, the software costs are 10x to 1000x lower.

Topology optimization is the least expensive technology to mitigate congestion when it is applicable. Factors that affect the cost effectiveness of the technology are really factors that affect whether the technology is applicable. The two factors that strongly affect if topology optimization technology is applicable in a specific transmission network are i) whether the transmission network in question is at least relatively meshed, and ii) whether the said network experiences or is expected to experience material transmission limitations.

C.3. Please describe the primary benefits associated with your product(s).

> *a. What are the technical, operational, and commercial benefits of your technology?*
>
> *b. Does your technology support broader public policy goals including, but not limited to, the integration of clean energy, emissions reductions, grid resilience, or cost savings for customers and ratepayers?*

By mitigating binding transmission limitations, grid reconfigurations identified by NewGrid Router increase the transmission network's transfer capability under modeled optimization conditions, enabling transfers that would otherwise be infeasible. The increased transfer capability reduces congestion costs and renewable curtailment, leading to reduced associated cost and emissions. Additionally, it improves systems reliability by reducing overload risks, and enhances resilience by making additional generation available during extreme events. The technology supports the integration of clean energy by improving the financial performance of renewable plants reducing their congestion risk, and by speeding up their interconnection process through uplocking grid capacity.

There are operational benefits as well: additional planned transmission and generation outages could be accommodated, and transmission operations and operations planning staff can be more productive in congestion management processes. From a planning perspective, these reconfigurations can temporarily mitigate transmission needs while major capital projects are underway. In addition, having reconfiguration solutions can help ensure planning portfolios provide good topology optimization flexibility in operations, and potentially avoid some capital projects.

Being a software technology, topology optimization does not require deploying physical devices. A software deployment provides optimization support for the entire system and can respond immediately to congestion in areas that have not previously experienced congestion. It can also provide effective support to mitigate transient/temporary congestion events with duration on the order of hours to weeks, for example due to outages.

C.4 Does your technology integrate with existing grid infrastructure and utility operation systems?

a. Are there unique requirements required to operationalize your technology (e.g., siting and permitting, workforce training, operability with utility systems, etc.)?

b. What is the typical deployment timeline for your solution from planning to operation?

c. Do you offer support or training for utilities to assist with the deployment and operation of your technology?

The NewGrid Router software package does integrate with existing utility operations systems. NewGrid Router can be run as a stand-alone tool, in which case the integration with other operations software systems is via input and output files. NewGrid Router takes as input the network model in any one of a number of standard file formats that can be produced by different standard power systems software and utility operation systems. In addition to a graphical user interface for viewing the analysis results, the outputs can also be saved in standard formats. NewGrid Router can also be integrated with utility operation systems directly and enable it to run in online mode, whereby data is continuously transmitted from the utility operations systems to NewGrid Router for online analysis.

NewGrid Router runs on premises on Windows servers. Software deployment can be quick, depending on the IT policies and processes of the utility in question, and the availability of IT staff. It is usually implementable within days to weeks.

NewGrid offers training and support on NewGrid Router, as well as studies and analyses as a service performed by NewGrid engineering staff, relying on NewGrid Router.

C.5. Where have your technologies been deployed to date?

a. Are there specific examples where your solution was deemed to be more cost effective than a traditional grid upgrade?

b. Are there specific types of projects or system conditions where your technology is particularly valuable?

c. Was the deployment subsidized by any government entities or others? If so, how important was this support to deployment?

NewGrid Router has been deployed in the Electric Reliability Council of Texas, ERCOT (since 2017) and in ISO New England (since 2022), to support operations planning processes, such as contingency planning and outage coordination. These deployments have had measurable operational impacts. For example, the use of NewGrid Router in ISO New England reduced by 31% on average the flows on the most heavily loaded constraint flows due to major planned outages and resolved the need for flow mitigation in half of the cases reported. [1] Use of NewGrid Router in ERCOT helped the RTO engineers to replace

[1] See Pablo Ruiz et al., Transmission Topology Optimization: A Software Grid-Enhancing Technology, presented at *ISO New England PAC Summit on GETs*, June 18, 2025, slides 6-8.

some outage mitigation plans that employed post-contingency load-sheding with reconfigurations that allowed removing post-contingency load shedding actions from the plans.[2]

In addition, NewGrid Router is used internally by NewGrid to provide congestion monitoring and mitigation services in the Midcontinent ISO (MISO) and Southwest Power Pool (SPP) footprints in the Midwest and Great Plains. Furthermore, consulting firms such as The Brattle Group and TCR use NewGrid Router to conduct studies and provide services for utilities and various electricity industry stakeholders in the U.S. and internationally.

While the main applications of topology optimization are for operations and operations planning support, there are a few examples where transmission reconfigurations served as permanent solutions (i.e., operating as normally open breakers). These solutions have either avoided a traditional grid upgrade or complemented other upgrades by making them more effective. These reconfigurations can be identified using NewGrid Router's optimization engine, which tends to be more efficient and thorough, or manually by expert engineering staff. Such examples include:

- In ISO New England, the "Transmission Planning [team] has developed projects to change the normal operating condition of devices to improve system performance. The most recent example was opening a circuit breaker at K Street which improved Boston Import limits."[3]
- In 2019 the most and fourth most expensive transmission constraints in SPP, both resulting from contingency limitations of a 69 kV line in Oklahoma, were permanently resolved with a transmission reconfiguration. Prior to their resolution in 2020, these constraints had been binding 16% of all the real-time market intervals in 2019, costing the SPP region about $25 million that year in the day-ahead and real-time markets. In addition to being costly and frequently binding, these constraints had resulted in $30 million of Transmission Congestion Rights underfunding.[4]

Usually, topology optimization technology is particularly valuable in transmission networks that:

- Are meshed, at least to some extent, providing additional paths that topology optimization can be used to reroute,
- Have substations designed with operational flexibility, such that they can be reconfigured,
- Experience significant levels of transmission limitations.

For example, twenty two case studies of topology optimization applications are summarized in this document. The highlights of these reported impacts include:

- Alliant Energy Iowa (Interstate Power and Light) customers saved 49% in congestion costs over two years ($24 million in savings),

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[2] Pablo Ruiz, Jay Caspary and Luke Butler, Transmission Topology Optimization Case Studies in SPP and ERCOT, FERC Tech Conf on Increasing Day-Ahead and Real-Time Market Efficiency and Enhancing Resilience through Improved Software (Docket No. AD10-12-011), June 24, 2020, slide 11., and Pablo Ruiz and Nick Steffan, Transmission Topology Optimization Operations and Market Applications and Case Studies, ERCOT DSWG Nov 17, 2017. Slide 12.

[3] See Brent Oberlin, Overview of Grid-Enhancing Technologies: ISO New England Perspective, presented at *ISO New England PAC Summit on GETs*, June 18, 2025, slide 9.

[4] See Southwest Power Pool MMU, State of the Market 2019, May 11, 2020. Pages 194-195, 199 and 214.

- A single transmission reconfiguration saved MISO $3.5 million in three weeks by mitigating the impact of a major planned transmission outage, reducing area wind curtailments by 86% (avoided 37 GWh of wind curtailments),
- SPP released up to 845 MW of stranded generation during Winter Storm Elliott under Energy Emergence Alert conditions by implementing two reconfigurations,
- Topology reconfigurations could have eliminated 98% of transmission overloads on ten significant MISO/SPP seam constraints in the Evergy footprint, reducing congestion costs on these constraints by 85%.

The ISO New England deployment of NewGrid Router was conducted as part of a partnership between NewGrid and ISO New England, enabled by support from the MassCEC. Another effort which started with funds from an external party was a proof-of-concept study with the UK system operator, formerly National Grid ESO, now National Energy System Operator. In that case, the innovation funding was provided by Ofgem, the energy regulator for Great Britain. In both cases, the external support was crucial to fund the start of the partnerships.

C.6 What, if any, adoption barriers has your company encountered?

> *a. Are there specific barriers that currently limit the use of your technology in Massachusetts relative to other jurisdictions?*
>
> *b. Please describe your experience in working with utilities or government entities in Massachusetts and/or other jurisdictions.*
>
> *c. Do you have any recommendations or considerations on how to facilitate cost-effective and timely adoption of advanced grid technologies?*

There are no specific barriers that limit use of topology optimization technology in Massachusetts. In fact, NewGrid topology optimization technology is used by ISO New England, to support long-term outage coordination decisions in the six New England states. Transmission limitations during major outages can be complex to manage, thus the specific application of the technology in outage coordination.

Congestion in New England has been very low the last few years relative to other regions,[5] reducing the potential benefits that the technology would have under current, normal conditions if it was used to support intra-day transmission operations. When congestion in the region increases in the future, the benefits that topology optimization would offer in intra-day operations will be more significant. Until then, the technology's role in intra-day operations support could focus on mitigating the impacts of extreme events, i.e., improving system resilience. For example, NewGrid Router could provide reconfiguration options to operators to increase generation deliverability and import capability from other regions as well as deliverability to load centers during winter weather events, when unplanned transmission and generation outages are more common, and generation margins are likely to be tight.

[5] See ISO New England 2024 Annual Markets Report, May 23, 2025, page 193.

NewGrid has had a very productive partnership with ISO New England, as indicated in the response to C.5. In addition, NewGrid has worked closely with two government organizations in the Commonwealth: MassCEC and MassVentures. Their support over the years in terms of funding to unlock opportunities, enabling partnerships, facilitating product and technology development, as well as providing mentoring resources, has been instrumental in helping NewGrid navigate innovation and advance technology deployment in the utilities industry.

To facilitate cost-effective and timely adoption of advanced grid technologies, we applaud the Commonwealth's continued support for proof-of-concept projects, pilot programs, and technology deployment. Beyond funding the technical and technology aspects of the initial onsite demonstrations and deployment, these efforts address critical regulatory, procedural, and partnership development. Initiatives such as this inquiry signals to the industry the Massachusetts government's commitment to unlocking grid capacity through the adoption of advanced technologies.

Conclusion

We appreciate the DPU's attention to the opportunities and barriers for GETs, including topology optimization. We hope that these comments help describe the potential value for GETs deployments in Massachusetts.

Sincerely,

Pablo A. Ruiz, Ph.D.

Chief Executive Officer

NewGrid, Inc.

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CTC GLOBAL
The Advanced Conductor

July 3, 2025

Chair Jamie Van Nostrand
Massachusetts Department of Public Utilities
1 South Station, 3rd floor
Boston, MA 02110

RE: Docket Proceeding: D.P.U. 25-69. Investigation Into the Use of Advanced Conductors, Grid-Enhancing Technologies and Other Advanced Transmission Technologies to Enhance the Performance of the Commonwealth's Transmission System in Applications that are Subject to Federal Jurisdiction, Pursuant to St. 2024, c. 239, § 121.

Dear Chair Van Nostrand, Commissioner Fraser, and Commissioner Rubin,

We appreciate the opportunity to respond to the Department's inquiry in Docket No. D.P.U. 25-69 regarding advanced conductors, grand enhancing technologies, and other advanced transmission technologies. Carbon composite advanced conductors can double transmission capacity in a matter of months by increasing capacity in existing rights of way. Unlike legacy steel core conductors that are both heavier and sag more, carbon composite advanced conductors accomplish this without having to be placed higher in the right of way, saving significant costs for consumers on the cost of steel structures while avoiding the need for new siting. Because carbon composite conductors are both stronger than steel and lighter, these capacity additions can often utilize existing structures, saving both significant time and money. The speed of new transmission capacity can further save consumers significant costs by reducing the cost of energy in both the capacity and wholesale energy markets. These are some of the elements that make carbon composite advanced conductors both the fastest and least expensive way to add significant transmission capacity to the grid.

CTC Global Corporation ("CTC") is the world's leading manufacturer of carbon core advanced conductors, with over 124,000 miles of its ACCC® Conductor in service worldwide. CTC is a US-based company, headquartered in Irvine, California, where it manufactures carbon core for ACCC Conductors using US-sourced components. CTC also produces ACCC Conductor around the world from four other manufacturing facilities.

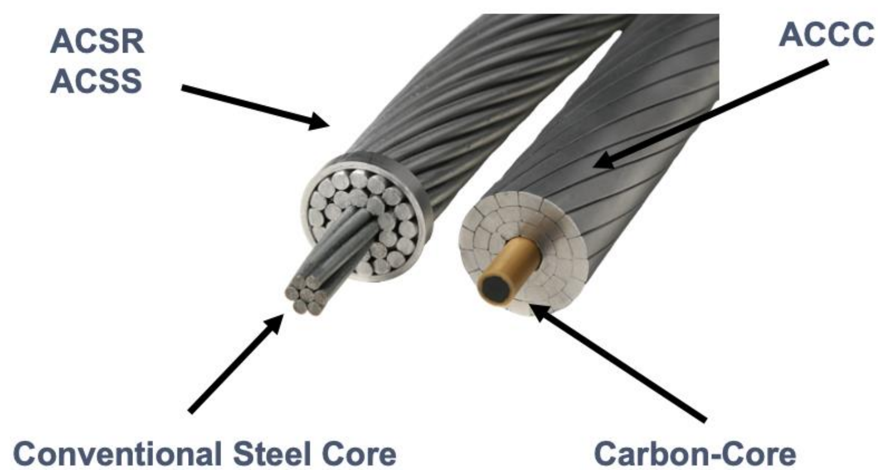
Respectfully submitted,

<u>/s/ Theodore J. Paradise</u>
Theodore J. Paradise
Chief Policy and Grid Strategy Officer
Paige Rodrigues
Senior Manager, Policy & Grid Strategy
David Townley
Senior Advisor, Policy & Grid Strategy
CTC Global Corporation

1. Please describe any advanced transmission or distribution technologies your company offers.

a. What is the current technology readiness level of your product(s)?

CTC invented and makes available the ACCC® Conductor (advanced carbon-core conductor) advanced transmission conductor technology, which is a carbon-composite core advanced conductor. While improved with significant research and development over the years, the product has been available commercially and installed for 20 years. The ACCC Conductor has been installed by more than 300 utilities in over 1,450 projects in more than 65 countries. Currently, there are more than 124,000 miles of ACCC Conductor installed and operating. The ACCC Conductor is at DOE readiness level TRL-9: fully commercial, available to commercial customers, and operating in a full range of environments.



CTC notes that the leading application for the ACCC Conductor (providing rapid and substantial increase in transmission capacity and reduced line losses) is “Advanced Reconductoring”. Advanced Reconductoring means that the ACCC conductor replaces the legacy conductor on an existing transmission structure (same weight for same diameter) using maintenance/storm recovery procedures, and without rebuilding all the structures (i.e., conventional approach), without needing construction permits or environmental permitting. Advanced Reconducting enables an increase in Amperage capacity of the line by 100% or more, a reduction in line losses by 25%- 40% (due to reduced resistance of the Advanced Conductor) and greatly reduces the line sag even at maximum amperage capacity thus increasing ground clearance and providing wildfire risk mitigation due to its very low sag.

Beyond the Advanced Reconductoring application, in many cases, ACCC will also result in significant benefits when used for new or rebuilt transmission lines. These benefits include lower total project costs (due to designs that include shorter structures, less substantial foundations, and potentially longer spans/fewer structures) as well as improvements to resiliency and efficiency (lower line losses). In addition, the ACCC Conductor's heavy ice load sag performance is the same as the best-performing steel core conductors; although not usually necessary, Ultra Low Sag (ULS) and/or Aluminum Zirconium alloy conductor options are also available to meet even the most extreme ice loading requirements in northern New England.

b. Is/are the product(s) commercially available?

Yes. The ACCC Conductor is commercially available and has been since 2005. From its U.S. supply chain, ACCC Conductor can be delivered in a variety of sizes in a matter of several weeks

2. Please describe the primary cost categories and amounts associated with your product(s).

a. What are the typical installation costs for your technology (per mile, per site, per kilowatt/megawatt, or as applicable)?

Project costs for increasing the powerline capacity vary depending on many factors, including voltage levels, urban-suburban-rural location, substation upgrades, whether kept at the same voltage or increased voltage, and many other factors. However, generally our experience across many hundreds of Advanced Reconductoring projects is that the PROJECT COST of the upgraded powerline is about 40%-60% of the cost of the traditional rebuild project for getting the same powerline capacity increase, and 75% less than adding capacity through a new build. The performance characteristics of the ACCC Conductor enables the powerline capacity increase (and other benefits) at a much lower total cost than the traditional new build or rebuild upgrade solution.

Additionally, double-digit total project cost savings, as compared to ACSR or ACSS designs, are possible when using ACCC Conductor as the standard of design for new or rebuild lines, making it often the least cost capital project option.

In addition, the use of ACCC Conductor in new builds and rebuilds can also result in a reduction of line losses by up to 40%. For example, for a 240 circuit mile line rebuild of 345kV in Texas, ACCC Conductor was installed as a live line project, ~35 additional MWs of power were delivered to load that would have otherwise been lost as heat. In addition to being less expensive as a capital cost, this loss reduction resulted in an ongoing savings of ~$15,000,000 per year.

b. What are the expected operations and maintenance costs over the technology's useful life?

The operations and maintenance cost of the ACCC Conductor is similar to that of the traditional ACSR (Aluminum Conductor Steel Reinforced) conductor or ACSS (Aluminum Conductor Steel Supported) conductor, except in corrosive environments, e.g., coastlines, industrial, or agricultural environments. In these corrosive environments, the ACCC Conductor will have a significantly *longer* operational life with much less maintenance due to the absence of the galvanic corrosion interface between the steel core and the aluminum current carrier in the ACSR and ACSS conductors. The ACCC conductor has NO galvanic metal-to-metal interface, and the carbon-core has no corrosion. Further, ACCC Conductor does not stretch out over time due to sag and thus does not require the same sort of retensioning work as steel core conductors.

c. What factors most strongly affect the cost effectiveness of your technology?

The cost-effectiveness of ACCC Conductor technology is largely driven by up-front capital considerations and long-term operational savings.

ACCC Conductors result in lower total project costs. On a wire-to-wire basis, ACCC has a higher initial cost per meter compared to ACSR and ACSS conductors. However, conductor is a relatively small portion of a transmission project. ACCC Conductor's carbon composite core is both lighter and roughly twice as strong as steel used in ACSR conductors, allowing for longer spans and/or fewer towers or shorter towers without upgrading foundations or widening rights-of-way. Reducing tower count, tower height, or simplifying permitting more than offsets the higher conductor price (note that conductor price is only a few percentage points of total project cost) and can significantly shorten overall project timelines, which itself can reduce costs significantly.

Over the life of the asset, ACCC Conductor's superior electrical and mechanical properties translate into substantial savings. For example, ACCC Conductors offer a 30% reduction in conductor resistance, which translates to 25%-40% lower line losses as well as lower infrastructure and maintenance costs.

To illustrate the benefits, consider a 40-mile 220 kV single-circuit transmission line using either a 1113 kcmil Finch size ACSR or a 1447 kcmil Munich size ACCC Conductor.

Line Losses: ACCC Conductors offer a 30% reduction in line losses, equating to 14,512 MWh/year or $1,451,220 annually at $100/MWh. Over 30 years, this results in savings of $43,536,572.

Generation Savings and energy and capacity market savings: this same reduction in losses / higher operating efficiency in everyday, real-world operating levels means that less generation capacity may be needed to serve load. This can reduce generation development costs. Further, by quickly adding capacity and not triggering new siting, new transmission headroom is created to both quickly interconnect new generation and move that generation across the system. In the case of New England, that can translate into fewer significant price spikes with significant cold weather and hot weather events, as well as reduce energy and capacity clearing prices in general. The addition of transmission capacity through the use of advanced conductors can quickly begin to pay for itself. In the winter of 2017 and 2018, a 15-day cold snap added over $1.5 billion in single-year fuel costs due to energy supply constraints. Allowing energy to move more freely and allowing for the addition of new energy from the interconnection queue can reduce those costs. For example, in a 2020 economic study,[1] ISO New England found that the addition of 8 GW of price-taking energy would reduce the RTO-wide production cost of electricity by half and would reduce the production of greenhouse gases by 1/3. The needed element for this effect to be recognized and scaled: transmission.

3. Please describe the primary benefits associated with your product(s).

a. What are the technical, operational, and commercial benefits of your technology?

Advanced Reconductoring with ACCC Conductor enables replacing the legacy ACSR conductor on an existing transmission structure (same weight for the same size ACSR conductor) using maintenance/storm recovery procedures, and without rebuilding all the structures (i.e., conventional approach), without needing construction permits, and without triggering environmental permitting. Through proper maintenance and life extension practices, even older structures can be reused for Advanced Reconductoring applications with ACCC Conductor, deferring the high costs of rebuilding existing structures that have remaining operational life without negatively impacting reliability. Advanced Reconducting enables an increase in amperage capacity of the powerline by 100% or more, a reduction in line losses by 25%- 40% (due to reduced resistance of the Advanced Conductor) and greatly reduces the line sag even at maximum amperage capacity thus increasing ground clearance and providing wildfire risk mitigation due to its very low sag. The lifetime of the conductor is expected to be equal to or greater than the life of the traditional ACSR conductor in most applications and is even better in corrosive environments, e.g., coastlines, industrial, or agricultural environments. (see comments in 2b above) ACCC Conductor's heavy ice load sag performance is the same as the best-performing steel core conductors. While not usually necessary, Ultra Low Sag (ULS) and/or Aluminum Zirconium (AZR) alloy conductor options are available to meet even the most extreme ice loading requirements in northern New England. Similar benefits, including double-digit total project cost savings, as compared to ACSR or ACSS designs,

[1] https://www.google.com/url?sa=t&source=web&rct=j&opi=89978449&url=https://www.iso-ne.com/static-assets/documents/2020/10/2019-anbaric-economic-study-final.docx&ved=2ahUKEwi6-7nEgKGOAxVcL1kFHUSlEB8QFnoECBgQAQ&usg=AOvVaw3YP41ZAx6HUJgJgfgvNIfn

are also possible when using ACCC Conductor as the standard of design for new or rebuilt lines.

Summarizing,
Technical benefits:

- Lighter, stronger, corrosion-free carbon-core
- For any given capacity level (amperage level), ACCC Conductor will operate at a cooler temperature than the steel-core ACSS or ACSR due to lower resistance for the same diameter / size conductor
- ACCC Conductor has greatly reduced sag vs ACSR/ACSS conductor
- ACCC Conductor has more aluminum and lower resistant aluminum on the same diameter as the ACSR and ACSS round wire conductors
- ACCC Conductor can replace ACSR conductor on existing transmission structures because the ACCC Conductor weighs the same as the same diameter ACSR conductor AND the existing structure was designed for that ACSR size and weight
- ACCC Conductor has 30% lower resistance than the ACSR conductor of the same diameter/size
- ACCC Conductor has a lifetime at least as long as ACSR steel-core conductor, and even longer in corrosive environments
- ACCC Conductor has ice load sag performance the same as best best-performing steel-core conductors

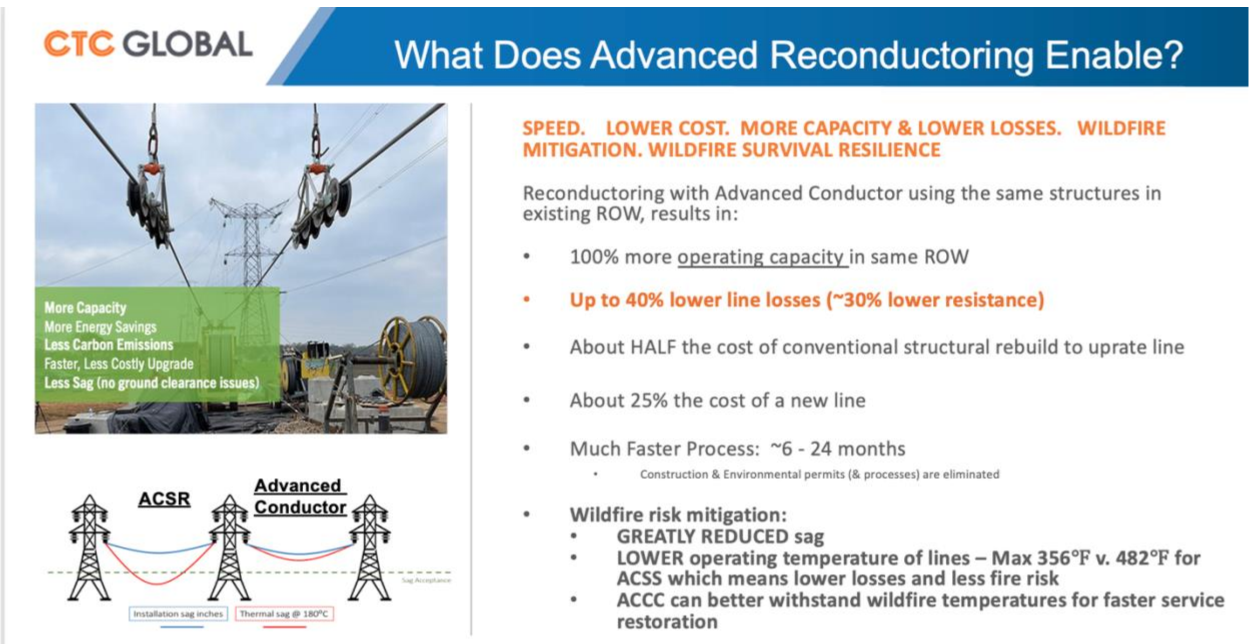
Operational Benefits:

- ACCC Conductor can deliver 100% or more increase in amperage capacity as the same diameter ACSR
- ACCC Conductor reduces line losses by 25%-40% versus the same size ACSR conductor
- The low sag of the ACCC Conductor
  - Increases ground clearance on existing transmission structures when reconductoring
  - Decreases the likelihood of starting a fire due to vegetation contact
  - Increases the likelihood of survival and rapid return to service (resilience) following a wildfire that goes user the powerline
  - Wildfire risk mitigation and resilience
  - Matches the best performance from steel-core conductor under ice load conditions

Commercial benefits:

- 40%-60% lower capital cost to upgrade a powerline by advanced reconductoring versus the traditional solution of rebuilding the structures and foundations to hold more weight of multiple and/or larger ACSR conductors. This reconductoring approach results in adding capacity for 75% less than a new build.

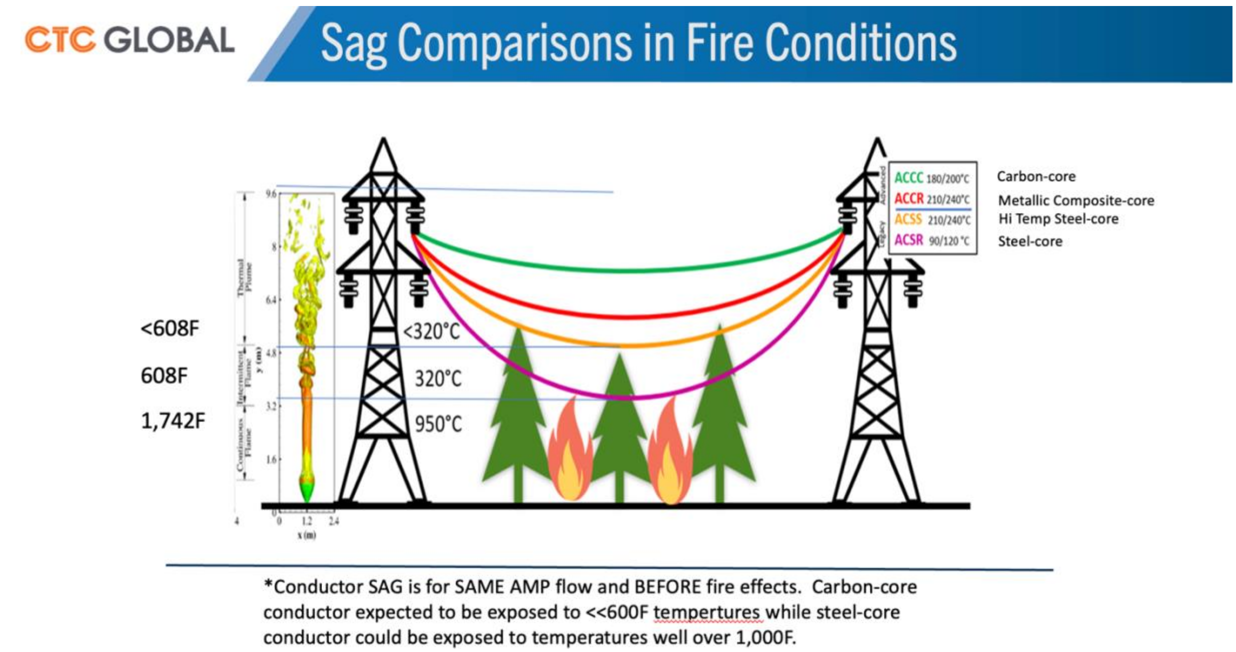
- Double-digit lower total project costs when using ACCC as the standard of design for non-reconductoring new or rebuild lines.
- 25% - 40% lower line losses reduces the energy cost to consumers by reducing fuel burned or energy procured to make up for the energy lost by heat while delivering electricity to the consumer AND reduces the amount of capacity required to serve the peak load (capacity otherwise needed to generate the energy lost to heat in the greater line losses with ACSR or ACSS conductor
- Lower wildfire costs due to the reduced probability of wildfire ignition by low-sag ACCC Conductor and the lower cost for powerline recovery following a wildfire (a higher probability of returning to service following a wildfire without need to replace conductor that has been damaged by wildfire heat, causing ACSR annealing, which requires ACSR replacement)



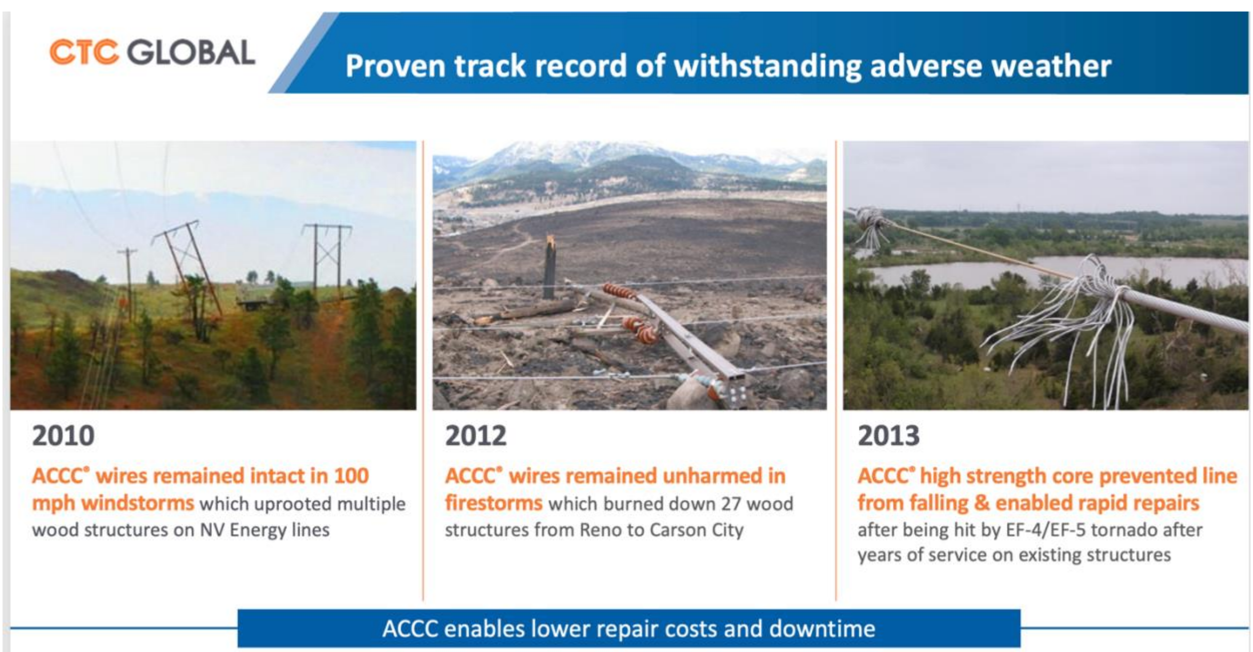
b. Does your technology support broader public policy goals, including, but not limited to, the integration of clean energy, emissions reductions, grid resilience, or cost savings for customers and ratepayers?

Yes. ACCC Conductor supports (as does CTC Global) rapid transmission capacity increase that can enable interconnecting more energy generation resources and supports increasing electrification by end-use technology and by new loads. The lower line losses of the ACCC conductor supports generation emission reductions as well as reduced cost to consumers for energy costs and generation capacity costs needed to serve loads. The ACCC Conductor's carbon-core enables grid resilience, especially:

- following wildfire exposure (remaining higher up on the transmission structures in a lower heat regime due to the lower sag



- due to the increased strength of the carbon-core that supports resilience from damaging high winds and other weather events that could cause steel-core conductors to fail;



- and, lack of corrosion in otherwise corrosive environments for metals due to having no metal-to-metal interface, where galvanic corrosion ultimately destroys the steel-core conductors.

A recent study by UC Berkeley in conjunction with GridLab and Lawrence Livermore National Lab was recently peer reviewed and published in the Proceedings of the National Academies of Science. It found:

As countries pursue decarbonization goals, the rapid expansion of transmission capacity for renewable energy (RE) integration poses a significant challenge due to hurdles such as permitting and cost allocation. However, we find that large-scale reconductoring with advanced composite-core conductors can cost-effectively double transmission capacity within existing right-of-way, with limited additional permitting. This strategy unlocks a high availability of increasingly economically viable RE resources in close proximity to the existing network. We implement reconductoring in a model of the US power system, showing that reconductoring can help meet over 80% of the new interzonal transmission needed to reach over 90% clean electricity by 2035 given restrictions on greenfield transmission build-out. With $180 billion in system cost savings by 2050, reconductoring presents a cost-effective and time-efficient, yet underutilized, opportunity to accelerate global transmission expansion.[2]

4. Does your technology integrate with existing grid infrastructure and utility operation systems?

Yes. More than 124,000 miles of installed ACCC Conductor demonstrates its successful integration in to grid around the world.

a. Are there unique requirements required to operationalize your technology (e.g., siting and permitting, workforce training, operability with utility systems, etc.)?

No "unique" requirements, but we do provide on-site training and project support to ensure rapid, successful installation of the ACCC Conductor. From installation crews across many countries that include emerging economies as well as first-world countries, the feedback is that the ACCC Conductor is easy and even faster to install than the traditional ACSR conductor.

[2] Accelerating transmission capacity expansion by using advanced conductors in existing right-of-way
Emilia Chojkiewicz, Umed Paliwal, et al. Edited by M. Granger Morgan, Carnegie Mellon University, Pittsburgh, PA; received June 4, 2024; accepted August 15, 2024 https://www.pnas.org/doi/10.1073/pnas.2411207121 The conductor utilized for this study is CTC Global's ACCC.

See, for example, this recent video by Southern California Edison that CTC Global was not involved with: https://energized.edison.com/stories/new-technology-increases-electricity-capacity

b. What is the typical deployment timeline for your solution from planning to operation?

For Advanced Reconductoring applications, the typical timeline is 6 months to 18 months. A recent Advanced Reconductoring project was completed in 8 months, uprating a transmission congestion point so that more offshore wind could be integrated into the grid. Deployment timelines when using ACCC Conductor for new or rebuilt lines are expected to be no longer than timelines experienced using traditional steel core conductors.

c. Do you offer support or training for utilities to assist with the deployment and operation of your technology?

Yes. CTC Global supports customers with project engineering analytical support, project deign insights and analysis, installation training, training to use the InfoCore® System for Quality Assurance both for installation QA and for future conductor QA following events that may have caused damage to powerlines, e.g., tornado, high-winds, potential line damage from shooting, etc.

While training to install ACCC Conductpr can be accomplished in a matter of hours and is in use in a range of utilities in both the first and developing world, CTC provides extensive training resources that continue to grow. For example, CTC recently entered into a partnership with Google in which Google is financially supporting the use of CTC ACCC Conductor in the US to accelerate transmission capacity for data center load growth. That financial support has been paired with financial support for training as well from Google. More information about the transmission RFI and RFP, as well as financial support and additional ACCC Conductor training resources, can be found here: https://blog.google/feed/ctc-global-partnership-us-electrical-grid-capacity/

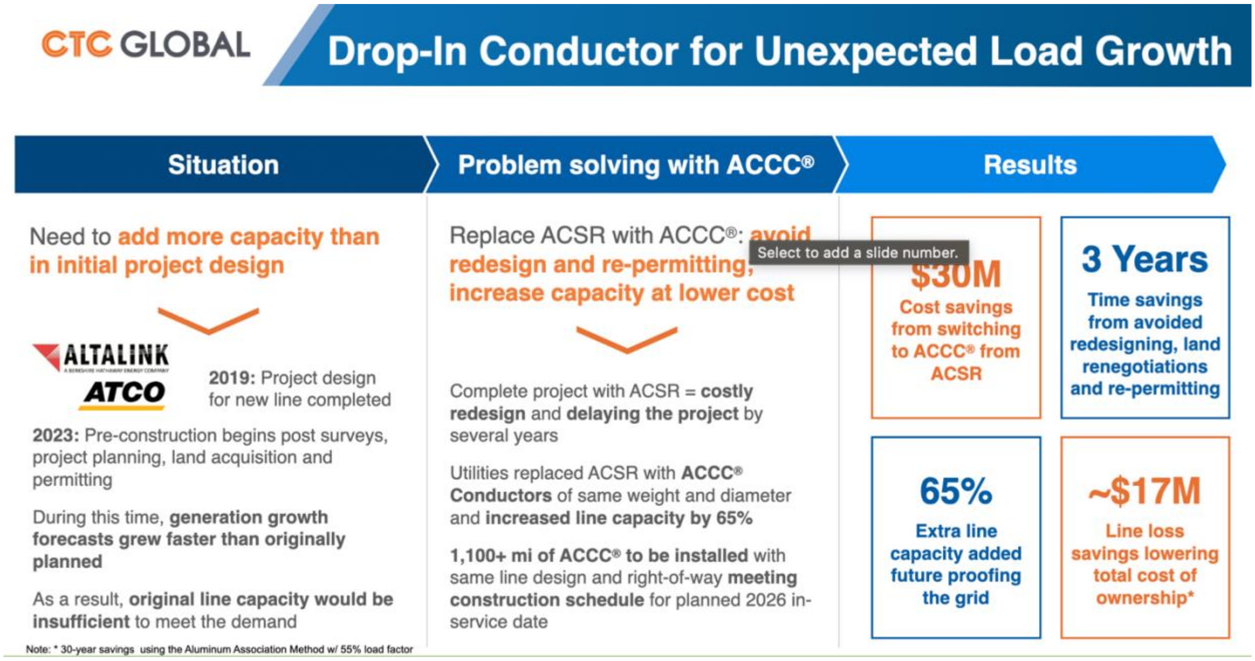
5. Where have your technologies been deployed to date?

The ACCC Conductor is installed in 65 countries. For this response, we will focus on the North American installations. In North America, as of April 2025, there have been 9,200 miles of ACCC Conductor installed in 55 US utilities in more than 30 states.

a. **Are there specific examples where your solution was deemed to be more cost effective than a traditional grid upgrade?**

Yes. Here are some specific examples:

Drop-in Conductor for Unexpected Load Growth: In 2019, Altalink and ATCO completed the project design for a new transmission line, but by 2023—when pre-construction surveys, planning, land acquisition, and permitting were underway—generation growth forecasts had accelerated beyond initial expectations. The originally specified ACSR conductor would no longer deliver sufficient capacity without triggering a costly and time-consuming redesign and re-permitting process. Instead, the utilities elected to swap in ACCC Conductors of the same weight and diameter, immediately boosting line capacity by 65% without altering the approved route or right-of-way. This drop-in solution allowed more 1,100 miles of ACCC Conductor to be installed on the original schedule for a planned 2026 in-service date, yielding **approximately $30 million in cost savings over ACSR**, shaving three years off project delivery, and cutting line losses to save an additional ~$17 million in lifetime ownership costs.



SCE Saved $87 M & Increased Line Capacity: Southern California Edison faced sag violations on its 230 kV, 137-mile Big Creek corridor and initially planned to rebuild or retrofit the entire line using traditional ACSR Dove conductors. That **route would have cost roughly $135 million** and required 48 months to complete. By specifying ACCC Dove Conductors instead, SCE avoided a full rebuild, **reduced project costs to $48 million**, and compressed construction from four years down to 18 months. The ACCC Conductor upgrade raised the line's thermal rating from 936 amps to 1,520 amps (a 60%+ increase), delivered a 40% improvement in conductor sag to eliminate violations, and cut line losses by 30%, collectively saving about $85 million in customer costs.

CTC GLOBAL

SCE Saved $87M & Increased Line Capacity

Utility:	Southern California Edison
Line configuration:	230 kv 137-mile single circuit line
ACCC® conductor installed:	411 conductor miles
Project objective:	SCE needed to rebuild 137 miles of the Big Creek transmission corridor to mitigate sag violations

Project details with traditional vs ACCC® conductor

	ACSR	ACCC®
Rebuild/retrofit required:	Yes	No
Conductor type:	ACSR Dove	ACCC® Dove
Project cost:	$135M	$48M
Time to completion:	48 months	18 months

ACCC® Solution

1 Increased line capacity

Increased the line's rating from 936 amps to 1520 amps, adding **60%+ more capacity**

2 Sag violation mitigation

Realized **40% improvement in line sag**, mitigating all violations and increasing overall line safety

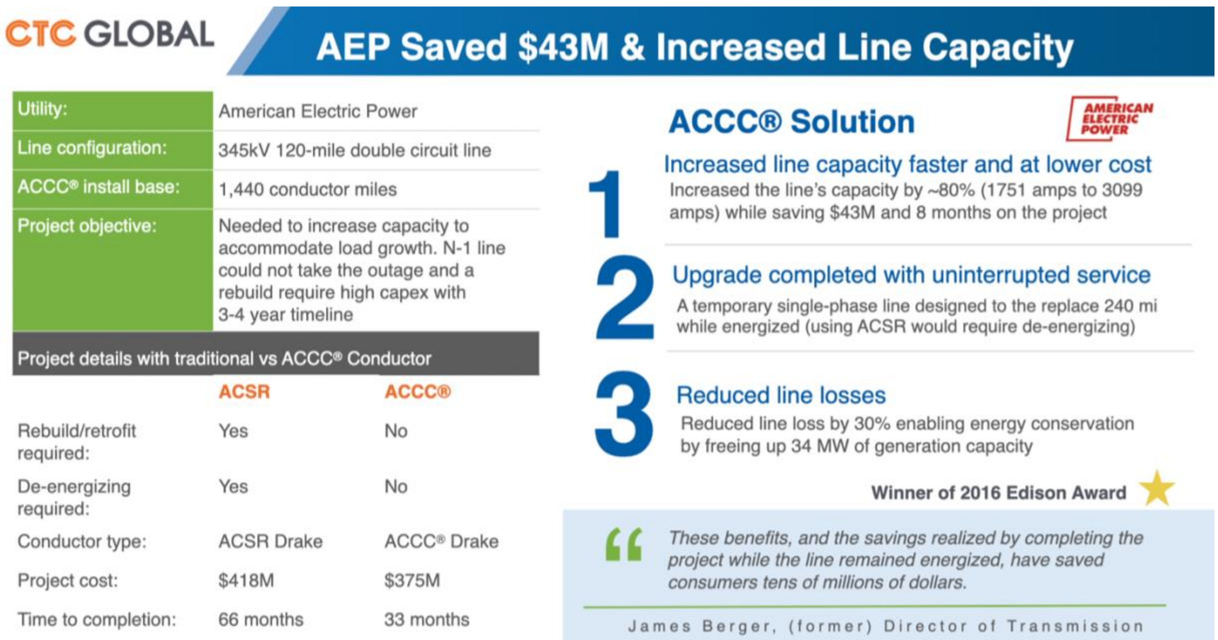
3 Reduced line losses

Reduced line loss by 30% enabling conservation of generation capacity and saving $85M in customer costs

"Reconductoring with ACCC® vs rebuilding saved years of time in permitting and construction, provided significant environmental advantages, and saved tens of millions of dollars in project costs.

SCE

AEP Saved $43 M & Increased Line Capacity: American Electric Power needed to boost capacity on a 345 kV, 120-mile double-circuit corridor to accommodate load growth and maintain reliability without taking the existing line out of service. A traditional ACSR Drake rebuild would have entailed de-energizing the line, a multi-year outage risk, and an estimated $418 million price tag over 36–48 months. Instead, AEP installed ACCC Drake Conductors, leveraging a temporary single-phase circuit to keep the line energized during replacement, and completed the 240-mile swap in 33 months for $375 million. The ACCC Conductor solution increased capacity by 80% (from 1,751 amps to 3,099 amps), enabled uninterrupted service throughout construction, and reduced line losses by 30%, freeing up 34 MW of generation capacity while **saving $43 million** and cutting project duration.



You can find more case studies here on the CTC Global website.

b. Are there specific types of projects or system conditions where your technology is particularly valuable?

The Advanced Reconductoring application is the fastest, lowest-cost way to add substantial grid capacity to the grid. The Advanced Reconductoring grid capacity upgrade solution is usually 40%-60% lower capital cost than the traditional structural rebuilding solution for attaining the same capacity uprate. Similar benefits, including double-digit total project cost savings, as compared to ACSR or ACSS designs, are also possible when using ACCC Conductor as the standard of design for new or rebuild lines.

c. Was the deployment subsidized by any government entities or others? If so, how important was this support to deployment?

Most of the installed projects in the USA have not had government subsidies. Some projects applied for GRIP awards in the 3 rounds of solicitation. So far, none of the GRIP award projects have been completed or installed.

On June 17, Google and CTC Global kicked off a joint initiative to speed U.S. grid upgrades utilizing ACCC advanced conductor, issuing an RFI (due July 14, 2025) for transmission projects that can start work as soon as possible, with priority for significant impact and near-term in-service dates. Respondents (states, utilities, and independent transmission developers) are encouraged to target lines serving existing or announced Google data centers and wholesale markets. Information regarding some of these areas can be found here: https://datacenters.google/locations/

Selected projects will receive:

- Cost Assistance: Funding to deploy ACCC® conductors and accelerate transmission capacity additions.
- Technical Analysis: Engineering studies to validate integration, electrical performance, and system impacts.
- Workforce Development: Funding for hands-on training for utility crews regarding ACCC Conductor installation and maintenance.

6. What, if any, adoption barriers has your company encountered?

The principal barriers to adoption of advanced conductors, including ACCC Conductor, have been engineering conservatism and misperceptions about the properties of advanced conductors.

a. Are there specific barriers that currently limit the use of your technology in Massachusetts relative to other jurisdictions?

For the last 120 years, many utilities have utilized ACSR steel-core conductors for many applications, as well as ACSS since the 1970s. In part, this is a program that has worked for regular capital deployment, and when the acquisition and development of new rights of way has not resulted in reliability issues or the inability to serve new loads. Load growth has been incremental, often at ~1% per year, and even flat in some years. In short, maximizing an existing right of way and prioritizing speed to power and overall project costs have not always been key drivers.

We see this changing in North America, where load growth from electrification, new manufacturing and reindustrialization, new large tech sector loads, and the retirement of older generating resources are giving rise to the need for significant new transmission to interconnect a historic interconnection queue of 2.5 TW of generating resources. As ICF found in its May 2025 report, load growth is now slated to expand by 78% between 2023 and 2030, resulting in the need to add 80 GW of new generation each year between 2025 and 2045 – numbers that are nowhere near being met due to the lack of needed transmission infrastructure.[3]

In some cases, there have also been misperceptions about ACCC Conductor performance in ice conditions and caution about adopting what are perceived as new technologies. CTC Global and third-party engineering analysis show that the ACCC Conductor's heavy ice load sag performance is the same as the best performing steel core conductors; although not usually necessary, Ultra Low Sag (ULS) and/or Aluminum Zirconium alloy conductor options are available to meet even the most extreme ice loading requirements in northern New England, Canada, and indeed, even the Swiss Alps. If utilities were to design their line rebuild projects to the properties of ACCC Conductor, this could result in shorter structures, less significant foundations, and/or longer spans, resulting in large cost savings and lines with less visual impact. In cases where tower condition enables reconductoring, utilities can double line capacity with ACCC Conductor without replacing structures – as they would need to do using their ACSS.

b. Please describe your experience in working with utilities or government entities in Massachusetts and/or other jurisdictions.

Government officials in the region are very supportive of the use of advanced conductors. We have seen support from regulators across the region, including with state government officials in Vermont, Connecticut, and Massachusetts, and at the federal level from both parties. In this video, Senator King from Maine holds up CTC's ACCC Conductor and talks about its benefits: see video at 1:37 and continuing: https://www.energy.senate.gov/hearings/2023/7/full-committee-hearing-to-examine-opportunities-for-congress-to-reform-the-process-for-permitting-electric-transmission-lines-pipelines-and-energy-production-on-federal-lands?utm_source=chatgpt.com.

[3] *How to Manage Surging Electricity Demand*, Lalit Batra, et al, ICF May 2025. https://www.icf.com/insights/energy/demand-growth-challenges-opportunities-utilities

Despite its wide global deployment of over 124,000 miles in a range of harsh conditions, from mountainous cold regions to tropical climates, to date, New England utilities have not made wide use of this technology, though. One utility has had it on their system for 20 years while another has decided to continue to continue to use ACSS steel core conductors on raised tower rebuild projects and new projects.

c. Do you have any recommendations or considerations on how to facilitate cost-effective and timely adoption of advanced grid technologies?

For all transmission projects, require utilities to demonstrate that they've considered designs using advanced conductors, where an advanced conductor is defined as a conductor that

- has at least 10% lower resistance than a same diameter (size) ACSR conductor,
- can provide at least 75% additional potential amperage capacity in projects up to and including 345kV under normal operating temperatures for the same diameter (size) ACSR conductor, and
- has a thermal expansion coefficient[4] no greater than that of a carbon-composite core conductor, ensuring that line sag is minimized, allowing for the use of existing structures or cost-saving and easier-to-site lower and fewer new structures

[4] The coefficient of thermal expansion of steel in nearly all PLS-CADD wire files is 11.5x10^-6/C. By comparison, ACCC has a dramatically better coefficient of thermal expansion than all steel core lines of 1.8x10^-6/C all the way down to 0.75x10^-6/C.

The lower resistance provides energy savings for the consumer and lower carbon emissions for the environment; the greater amperage capacity provides grid capacity, reliability, and resilience; and the low thermal expansion provides wildfire risk mitigation and grid resilience, while reducing siting risks, delays, and costs.

7. Additional information regarding this docket:

a. Correction of claims made in this docket regarding "Giga Steel" conductors:

Below, we have provided some technical clarifications regarding claims made in this docket about so-called "Giga Steel" Conductors:

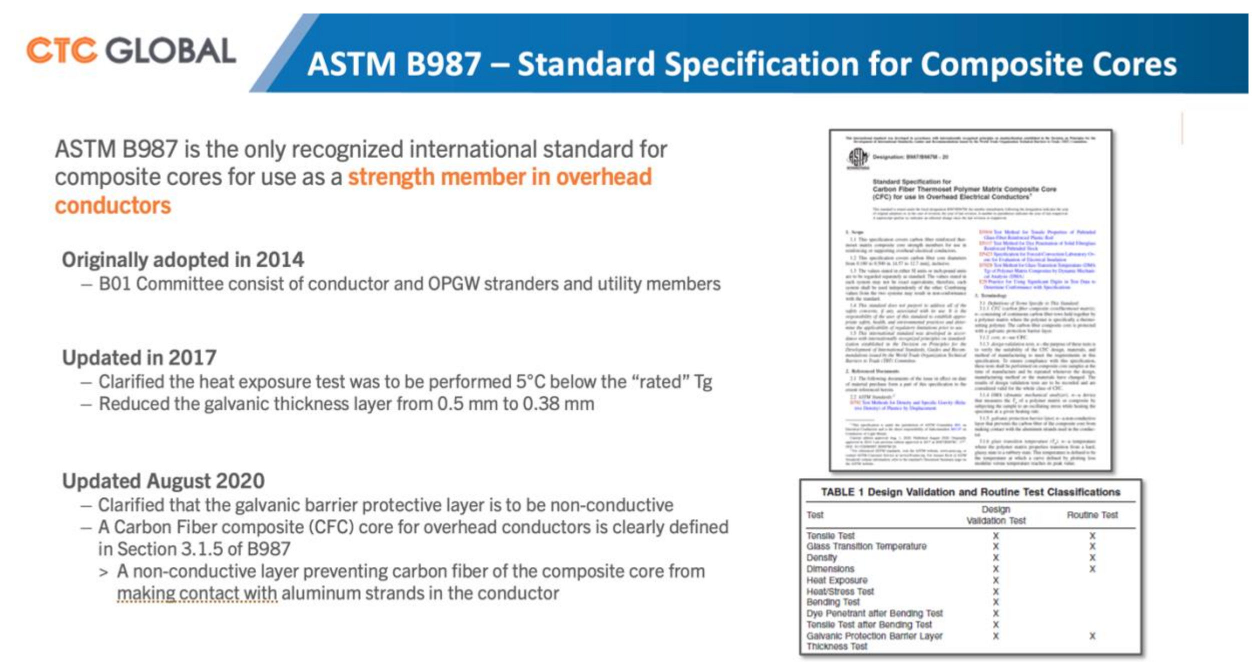
- Advanced Conductor Label: Giga Steel is repeatedly marketed as an "Advanced Conductor," but this classification is debatable. It does not meet the definition of an Advanced Conductor as set out by the Department of Energy in its April 2024 liftoff report: "*Conductors that increase line capacity by >1.5x (at a similar weight per foot); advanced conductors use composite core (instead of traditional steel cores) to improve efficiency and increase capacity with limited sag.*" The DOE has defined newer steel core conductors in that same report as "enhanced" conductors.
- Design Tradeoff: Giga Steel designs can provide either a 218% ampacity increase or a reduction in wind/ice loading area, *but not both*. These outcomes depend on two distinct approaches: OD match vs. kcmil match.
- Sag Reduction Misconception: The claim of "lower sag" is incorrect. Giga Steel may offer higher tensile strength, but the modulus (stiffness) remains unchanged unless steel area increases. For the same maximum tension and area of steel, sag will slightly exceed the sag of ACSR. To reduce sag, tension must be increased, raising structure costs.
- Example Conductor Design from White Paper– ACSS/TW/MA8 Mississippi: This design reduces steel core area to increase aluminum content, resulting in lower modulus and higher sags. This new design exceeds the sag of both ACSR and traditional ACSS. Because removing steel and replacing it with aluminum slightly reduces the weight of the complete conductor, there is a slight sag improvement over ACSS/TW/MA2 Suwannee, the traditional trap wire OD equivalent.
- Reconductor Implications: Reconductoring with ACSS *increases* sag compared to older ACSR for the same ultimate tension. Managing this requires either raising tower heights or increasing tension, both add cost.
- Tripling Capacity Misconception: Tripling capacity typically necessitates a larger conductor than the base ACSR size. If this is acceptable, a larger ACSR could also be

acceptable, reverting the analysis back to only doubling capacity, but again, this would require tower rebuilds or taller tower heights to manage the sag of the heavier and much more thermally pliable steel core conductor.

- Corrosion Resistance: Giga Steel offers no improvement in corrosion resistance over standard ACSS or ACSR using mischmetal-coated steel.
- Line Loss vs. Sag Tradeoff: The ACSS/TW/MA8 Mississippi design may reduce line losses by minimizing steel area, but this comes at the cost of higher or excessive sag.
- INL Cost Claim Challenge: INL suggests reconductoring can achieve higher capacity at 20% the cost of new line construction. This is unrealistic with the proposed Giga Steel design, as sag will exceed ACSR limits unless the line structures are rebuilt or structurally upgraded to handle added sag and/or tension.

b) ACCC is the most tested carbon core advanced conductor and holds the most certifications:

Safety, grid reliability, and strength are paramount for CTC. No other carbon core advanced conductor has gone through the extensive testing that CTC has, and no other has the certifications that CTC has as a manufacturer and that ACCC Conductor has as a carbon core advanced conductor. Below is information regarding the range of testing of ACCC Conductor.



CTC GLOBAL
The Advanced Conductor

CTC GLOBAL

ACCC® Testing & Validation

Core Testing

2.1.1 Tensile Testing
2.1.2 Flexural, Bending & Shear Tests
2.1.3 Sustained Load Tests
2.1.4 Tg Tests
2.1.5 CTE Measurements
2.1.6 Shear Testing
2.1.7 Impact and Crush Testing
2.1.8 Torsion Testing
2.1.9 Notched Degradation Testing
2.1.10 Moisture Resistance Testing
2.1.11 Long Term Thermal Testing
2.1.12 Sustained Load Thermal Testing
2.1.13 Cyclic Thermal Testing
2.1.14 Specific Heat Capacity Testing
2.1.15 High Temperature Short Duration
2.1.16 High Temperature Core Testing
2.1.17 Thermal Oxidation Testing
2.1.18 Brittle Fracture Testing
2.1.19 UV Testing
2.1.20 Salt Fog Exposure Tests
2.1.21 Creep Tests
2.1.22 Stress Strain Testing
2.1.24 Micrographic Analysis
2.1.25 Dye Penetrant Testing
2.1.26 High Temperature Shear Testing
2.1.27 Low Temperature Shear Testing

Mechanical Conductor Testing

2.2.28 Stress Strain Testing
2.2.29 Creep Testing
2.2.30 Aeolian Vibration Testing
2.2.31 Galloping Tests
2.2.32 Self Damping Tests
2.2.33 Radial Impact and Crush Tests
2.2.34 Turning Angle Tests
2.2.35 Torsion Tests
2.2.36 High Temperature Sag Tests
2.2.37 High Temperature Sustained Load
2.2.38 High Temperature Cyclic Load Tests
2.2.39 Cyclic Ice Load Tests
2.2.40 Sheave Wheel Tests
2.2.41 Ultimate Strength Tests
2.2.42 Cyclic Thermo-Mechanical Testing
2.2.43 Combined Cyclic Load Testing
2.2.44 Conductor Comparison Testing

Mechanical Conductor Testing

2.4.55 Current Cycle Testing
2.4.56 Sustained Load Testing
2.4.57 Ultimate Assembly Strength Testing
2.4.58 Salt Fog Emersion Testing
2.4.60 Static Heat Tests
2.4.61 Suspension Clamp Testing
2.4.62 Thermo-Mechanical Testing
2.4.63 Cyclic Load Testing
2.4.64 EPRI Longevity Assessment (1,500 cycles)

Electrical Conductor Testing

2.3.45 Resistivity Testing
2.3.46 Power Loss Comparison Testing
2.3.47 Ampacity
2.3.48 EMF Measurements
2.3.49 Impedance Comparison Testing
2.3.50 Corona Testing
2.3.51 Radio Noise Testing
2.3.52 Short Circuit Testing
2.3.53 Lightning Strike Testing
2.3.54 Ultra High Voltage AC & DC Testing

Field Testing

2.5.64 Ambient Temperature
2.5.65 Tension, Sag, and Clearance
2.5.66 Conductor Temperature
2.5.67 Electric Current
2.5.68 Wind Speed and Direction
2.5.69 Solar Radiation
2.5.70 Rainfall
2.5.71 Ice Buildup
2.5.72 Splice Resistance
2.5.73 Infrared Measurements
2.5.74 Corona Observations
2.5.75 Electric and Magnetic Fields
2.5.76 Wind and Ice Load Measurements
2.5.77 Vibration Monitoring

CTC GLOBAL

Design Validation Test Reports

Testing performed at **CTC's Irvine ISO 17025 Testing facility**
All testing witnessed by Element, an outside testing company
B987 Design Validation Test reports available for all ACCC Core sizes and types

This extensive testing and quality assurance helps ensure that ACCC Conductor is not only the fastest and most cost-effective way to add transmission capacity, it also helps ensure that ACCC Conductor provides extreme durability, longevity, and safety.

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June 19, 2025

Massachusetts Department of Public Utilities
1 South Station
3rd floor
Boston, MA 02110
Submitted via email to dpu.efiling@mass.gov and andrew.w.strumfels@mass.gov.

Re: Docket Proceeding: D.P.U. 25-69. Investigation Into the Use of Advanced Conductors, Grid-Enhancing Technologies and Other Advanced Transmission Technologies to Enhance the Performance of the Commonwealth's Transmission System in Applications that are Subject to Federal Jurisdiction, Pursuant to St. 2024, c. 239, § 121.

Dear Chair Nostrand, Commissioner Fraser, Commissioner Rubin,

Bekaert Corporation is pleased to respond to the Massachusetts Department of Public Utilities' inquiry (D.P.U. 25-69) regarding Grid-Enhancing Technologies and Advanced Conductors. As a global leader in steel wire transformation, Bekaert offers innovative steel core strands for Advanced Conductors known by the name of Aluminum Conductor Steel Supported/Trapezoidal Wire (ACSS/TW). The advanced steel cores are designed to enhance grid capacity, reliability, and resilience. Below, we address the inquiry's questions, drawing on insights from the Midcontinent Independent System Operator (MISO) Transmission Cost Estimation Guide, Idaho National Laboratory (INL) Advanced Conductor Scan Report, and Bekaert's Ratepayer Impact and Giga Core White Papers, with a focus on total cost of ownership (TCO) and reliability benefits for Massachusetts' grid modernization goals.

Bekaert Corporation North America, established in the 1950s and expanded in the 1970s, operates fifteen locations in the United States. Known for our expertise in steel wire transformation and coating technologies, Bekaert is the largest independent manufacturer of steel wire solutions in North America. In Arkansas, Bekaert manufactures steel cores for domestic overhead transmission conductors, crucial for reliable power transmission infrastructure. With nearly 1,600 employees in the United States, Bekaert continues to lead in innovation and quality in the energy sector.

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1. Description of Advanced Transmission or Distribution Technologies

a. Giga-Strength Steel Core (MA8):

Bekaert's steel core solutions for ACSS/TW conductors are highlighted by our pinnacle achievement, the Giga-Strength Steel Core (MA8). The advanced steel core product offering allows for high-temperature, low-sag (HTLS) solutions that increase transmission capacity by up to 218% compared to traditional Aluminum Conductor Steel Reinforced (ACSR) conductors, leveraging existing infrastructure[1]. These conductors use annealed aluminum strands for enhanced conductivity (63% IACS vs. 61.2% for ACSR[2]) and an ultra-high-strength steel core (MA8 Giga Core, >305 kpsi tensile strength) to operate at temperatures up to 250°C with lower sag. The trapezoidal wire geometry reduces wind and ice loading, making it ideal for Massachusetts' coastal and winter conditions. The MA8 Giga Core's 7 or 19-wire strand configuration, coated with Bezinal® (zinc-aluminum alloy), enhances corrosion resistance and flexibility, as detailed in Bekaert's Giga Core White Paper.

b. Technology Readiness Level (TRL):

ACSS/TW conductors with Bekaert's advanced steel cores are at TRL 9, fully mature and deployed globally, per INL's Advanced Conductor Scan Report, which notes over 95% of U.S. utilities have adopted advanced conductors like ACSS/TW. The MA8 Giga Core builds on proven High Strength (MA3) and Ultra High Strength (MA5) core designs, with field validations confirming its performance[5,6].

c. Commercial Availability:

These conductors are commercially available through Domestic manufacturers, supporting rapid production for utility-scale projects. Compliance with ASTM, CSA, IEEE, ISO 9001:2008, and ISO 14001:2004 standards ensure quality and scalability.

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2. Primary Cost Categories and Amounts

a. Typical Installation Costs:

Per the MISO Transmission Cost Estimation Guide, costs for advanced conductors like ACSS can be within 2-5% the cost of a similar diameter ACSR. This can be confirmed by actual case studies from Eversource Energy. Bekaert's advanced steel cores for ACSS/TW conductors align with these estimates, with installation costs reduced due to compatibility with standard ACSR techniques[1].

b. Expected Operations and Maintenance (O&M) Costs:

Bekaert's Ratepayer Impact White Paper calculates O&M costs for advanced conductors at different loads by using a Fixed charge rate on a conductor (Annual charge as percentage of total installed cost, for operation and maintenance of conductors.) of 19% and a Fixed charge rate on generation capacity (Annual charge as a percentage of capital investment, for operation and maintenance of generation assets needed to cover the line losses) of 17% over a 50 year lifespan[2]. The MA8 Giga Core's Bezinal® (including MA2-5) coating minimizes corrosion-related maintenance, particularly in coastal environments, reducing costs compared to ACSR. The INL report confirms advanced steel core conductors' lower maintenance due to durability[1].

c. Factors Affecting Cost-Effectiveness:

Capacity Increase: Doubling or tripling capacity on existing lines avoids new infrastructure costs[1,4].

Line Loss Reduction: 63% IACS conductivity saves $0.01–$0.03 per kWh, as quantified in Bekaert's Ratepayer Impact White Paper.

Environmental Resilience: Corrosion resistance lowers O&M in Massachusetts' climate.

Scale and Incentives: Larger projects and state subsidies enhance TCO, aligning with MISO's cost allocation principles for regional benefits. The MA8 Giga Core's high strength and recyclability further optimize TCO, as detailed in Bekaert's Giga Core White Paper. Existing installation techniques apply with advanced steel core technology.

3. Primary Benefits of the Technology

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a. Technical, Operational, and Commercial Benefits:

Technical: Bekaert's advanced steel cores >305 kpsi strength allows for a smaller inner diameter core. The space savings can be replaced with more aluminum allowing higher ampacity and lower line loss (resistance)[4]. Steel cores have excellent modulus of elasticity and is the top choice to handle ballast sag (Ice Loading). The 19-wire strand enhances flexibility and resilience with multiple core wires to increase the safety factor.

Operational: Advanced steel core conductors safely operate at high temperatures of 250 degrees Celsius and in high ice/wind areas, perfect for peak load situations where electricity demand is high. These conductors are the most reliable and resilient material options as variations have been in operation since the grid's inception in the early 1900's. Lineman are trained in this technology and supply chains are setup to handle demand.

Commercial: TCO savings stem from 218% capacity increases, 25% line loss reduction, and minimal O&M, per Bekaert's Ratepayer Impact White Paper.

b. Support for Public Policy Goals:

Clean Energy Integration: Increased capacity supports Massachusetts' offshore wind and solar goals, aligning with INL's emphasis on advanced conductors for renewable integration[1].

Emissions Reductions: Reduced line losses lower greenhouse gas emissions. Steel core conductors offer the lowest carbon footprint of any advanced conductor type (cradle to gate analysis SCS Global Services available upon request).

Grid Resilience: Advanced steel core conductors withstand extreme weather, enhancing reliability[1].

Cost Savings: Lower TCO and avoided infrastructure costs reduce ratepayer impacts, consistent with MISO's benefit-cost framework yielding 2.2x benefits for transmission upgrades[3].

4. Integration with Existing Grid Infrastructure

a. Unique Requirements:

Sitting and Permitting: No unique requirements, as ACSS/TW uses existing rights-of-way[1].

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Workforce Training: Standard ACSR installation techniques apply, with minimal training needed, as highlighted in Bekaert's Giga Core White Paper.

Operability: Compatible with existing fittings, wedges, and SCADA systems, ensuring seamless integration.

b. Typical Deployment Timeline:
Reconductoring projects take 6–18 months, per MISO's planning timelines, including permitting and installation. New lines require 12–24 months. Compatibility with existing infrastructure accelerates deployment.

c. Support and Training:
Bekaert and our conductor partners provide technical consulting, installation guidelines, and training, ensuring utilities can deploy and maintain ACSS/TW conductors effectively.

5. Deployment Examples

a. Cost-Effectiveness Examples:
INL's report cites many U.S. projects achieving 2–3x capacity at 10–20% of new line costs, applicable to Massachusetts' aging grid. A few have been detailed below.

Eversource: uses ACSS (Figure A-48) in transmission systems and had previously standardized on its use. Eversource prefers to use ACSS instead of ACSR because of the increased current carrying capacity. In 2023, Eversource announced that Eversource would be using ACSS with E3X coating as an enhancement to the ACSS for improved efficiency.

Avangrid: Used ACSS in their system on a long span over the Housatonic River. The Derby Junction-Ansonia project is an example of how utilities have been increasing capacity on existing corridors. United Illuminating rebuild considered ACSR and ACSS, and ultimately selected ACSR to meet future needs.

National Grid: Commenced an upgrade of 157 miles of transmission line from Edic to New Scotland and from New Scotland to Leeds with 954-kcmil ACSS Cardinal and 795-kcmil ACSS Drake conductors. The upgraded line has entered service in 2023.

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Duke Energy: Commonly uses ACSS and ACSS/TW. Duke Energy has experience with composite core conductors. In 2022, Duke Energy testified to the North Carolina Utilities Commission that Duke no longer considers composite core conductors due to recent installation concerns.

Consolidated Edison: Is a partner in a 17.5-mile transmission project that ties the Cricket Valley Energy Center to one of its substations. The ACSS conductor was selected for the New York Energy Solution project and for Cricket Valley Energy Center transmission based upon consideration of construction costs, line losses, and line performance for the line rating. New York is aggressively building capacity to connect lower cost renewable generation in the upstate region to the city. NY Transco completed a 54-mile 345-kV rebuild project along existing 115-kV corridors using ACSS. ACSS/E3X was selected for a short section of the line, which enabled reconductoring of existing 345-kV structures.

Dominion Energy: Used ACSS for high-capacity lines and has a standard to use ACSS/TW for new and reconductored 230-kV circuits. Recognized benefits of using ACSS for high-capacity applications have been codified in Dominion Energy's strategy.

Duquesne Light: Used ACSS/TW to reconductor multiple projects, including a 7-mile transmission line installed on towers constructed in the 1960s.

Evergy: Predecessor company KCP&L performed a live line reconductoring using ACSS on a 32-mile line connecting the LaCygne power station. The project used an ACSS/TW conductor to replace the existing ACSR conductor. The cost savings of the added transmission capacity paid for the cost of the upgrade in 14 months. There are other reconductoring projects in the queue for Evergy along with several historic use cases. The Maryville to Creston 161-kV Rebuild is a typical case and is a reconductoring effort for 62.4 miles using 556.5 ACSS Parakeet conductor costing ~$14,900,000. Evergy has made their analytic process for selecting candidate corridors and technologies for reconductoring open to the public. The company is forward-thinking regarding new technology but is looking for the best design fit for their system and geography.

Allegheny Power: Now part of First Energy, utilized ACSS and ACSS/TW in several different reconductoring, rebuilds, and new applications. ACSS conductor was chosen for projects noted in 2016, 2017, 2019, 2022, and 2023 for lengths under 20 miles on 138-kV and 345-kV transmission lines. On the Dowling-Midway project, a 336.4-kcmil ACSR conductor was replaced with a 336.5-kcmil ACSS conductor without replacing the existing

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lattice structures. This indicates the existing structures had sufficient clearance for the sag from the ACSS. On the Black River Carlisle-Lorain project, a 954-kcmil ACSR was replaced with a smaller 795-kcmil ACSS/TW. It was noted in planning documents that while the ACSS conductor was physically smaller, it had a larger current carrying capacity.

Northwestern Energy: One 20-mile section of a 100-kV line between the cities of Great Falls and Two Dot was constructed with an ACSS/TW/MA5 conductor with ultra-high strength steel in a project, which has received national media attention as an example of a utility choosing a lower loss conductor. The annealed aluminum of the ACSS conductor increases conductivity compared to ACSR and the trapezoidal shaped wires allow more aluminum to be packed in the same diameter as a traditional ACSR. This project was undertaken in 2021. One of the primary motivating factors for the project between Great Falls and Two Dot was wildfire prevention. The ~20-mile section was through a heavily wooded area so the reduced sag of the ACSS conductor, in addition to the use of modern steel structures, reduced the risk of fires in this historically wildfire prone region. Additionally, the conductor has increased efficiency, which provides more value to the utility and ratepayers. It was estimated if the entire 105-mile line was replaced with this ACSS/TW conductor the total savings could be as much as $440,000 per year. This project was recently used as an example for state regulators to argue for increased incentives for utilities to adopt advanced conductors in the state of Montana.

b. Valuable Project Types and Conditions:
Reconductoring: Ideal for upgrading ACSR lines to meet electrification and data center demands. ACSS conductors excel in high ice and wind areas.

Coastal Climates: Corrosion resistance excels in Massachusetts' environment.

Renewable Integration: Supports offshore wind connections.

Congested Corridors: Highest aluminum area maximizes capacity in constrained areas[1].

c. Subsidies and Importance:
Some deployments, including U.S. pilots, received DOE grants[1]. Subsidies accelerate adoption by offsetting upfront costs, critical for utilities with limited capital.

6. Adoption Barriers and Recommendations

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a. Barriers in Massachusetts:
Awareness: Limited utility familiarity with advanced conductors[1].

Permitting Delays: Even reconductoring faces regulatory hurdles.
Upfront Costs: Despite TCO savings, initial investment is a barrier without financing[3].

b. Experience with Utilities and Governments:
Bekaert has partnered with conductor manufacturers and utilities, deploying advanced steel cores for ACSS/TW conductors in Massachusetts as described in above examples.

c. Recommendations for Adoption:
Streamlined Permitting: Expedite approvals for reconductoring.

Incentives: Expand state grants, mirroring DOE's GRIP program.

Education: Host D.P.U.-led workshops on advanced conductor benefits, using MISO's stakeholder engagement model.

Planning Integration: Incorporate more advanced steel core conductors into Massachusetts' grid plans.

Bekaert's advanced steel cores used in ACSS/TW conductors offer a TRL 9, commercially available solution to enhance Massachusetts' grid. By delivering 218% capacity increases, 25%-line loss reductions, and extreme weather resilience. Our technology supports clean energy integration, emissions reductions, and ratepayer savings. We welcome collaboration with the D.P.U. and utilities to continue deploying this technology.

7. Certification

Bekaert Corporation certifies that the information provided is complete and accurate to the best of our knowledge.

Thank you for considering our advanced conductor technologies. We are available to provide additional information or clarification as needed.

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Sincerely,

Daniel Berkowitz
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8. References

[1] Idaho National Laboratory Report No. INL/RPT-23-75873 "Advanced Conductors Scan Report"

[2] Aluminum Association Guide 54, "Estimating the Cost of Line Losses"

[3] Midcontinent Independent System Operator (MISO) 2024 Transmission Cost Estimation Guide.

[4] D. Berkowitz, "Comparing Advanced Cores – Achieving Maximum Grid Capacity," CIGRE US National Committee, Proceedings of 2024 Grid of the Future Symposium.

[5] I. Banas, M. Bindzar, "High Temperature Wires as a Replacement for ALFE240," Proceedings of 2023 CIRED Conference, Czech Republic, November 2023.

[6] M. Mach, M. Kincl, et al., "The Intent to Use High Temperature Wires in Čez Distribuce," Proceedings of 2023 CIRED Conference, Czech Republic, Nov. 2023.

AMP COALITION

July 3, 2025
VIA EMAIL
Andrew Strumfels
Hearing Officer
Massachusetts Department of Public Utilities

RE: Response to Request for Comments in MA D.P.U. 25-69

Dear Andrew,

The Advancing Modern Powerlines (AMP) Coalition respectfully submits these comments in response to the Massachusetts Department of Public Utilities' inquiry D.P.U. 25-69: "Investigation Into the Use of Advanced Conductors, Grid-Enhancing Technologies and Other Advanced Transmission Technologies to Enhance the Performance of the Commonwealth's Transmission System in Applications that are Subject to Federal Jurisdiction," issued June 2, 2025, pursuant to St. 2024, c. 239, § 121.

High Performance Conductors (HPCs) represent a proven, cost-effective, and rapidly deployable solution for modernizing the electric grid. HPCs significantly increase transmission capacity, improve system efficiency, and reduce environmental and siting impacts compared to traditional infrastructure buildout. While HPC technologies have been commercially available for over two decades and are in use in more than 60 countries, adoption in the U.S. has lagged behind. Increased deployment of HPCs presents an opportunity for Massachusetts to maximize the use of existing rights-of-ways while advancing clean energy, resilience, and affordability goals.

We appreciate the Department's leadership in initiating this proceeding and hope the enclosed responses are helpful in informing its evaluation of High Performance Conductors. We are happy to provide additional detail or engage further with D.P.U staff as requested.

Sincerely,

Nathan Shreve
AMP Coalition

RESPONSES

<u>QUESTION 1: Please describe any advanced transmission or distribution technologies your company offers</u>

The AMP Coalition is an ad hoc coalition of High Performance Conductor technology providers and manufacturers, including CTC Global Corporation, TS Conductor, VEIR, and MetOx. AMP's goal is to further the use of High Performance Conductors as a tool for modernizing and increasing grid capacity, as well as improving the overall resilience, reliability, and energy efficiency of the grid.

High Performance Conductors (HPCs) is a term that encompasses modern conductor technologies which have greater performance characteristics when compared to traditional conductors (e.g., ACSR, ASCC), including increased capacity, higher efficiency, and less thermal sag. We categorize HPC offerings into two categories:

- **Carbon and Composite Core Conductors**, also known as Advanced Conductors, are overhead, bare conductors that use a trapezoid shaped wire of annealed aluminum to carry electrical current and use a carbon or composite core for support. Carbon and composite core conductors have three key advantages over traditional conductors: stronger and lighter weight cores, which allows for more aluminum to be added to the conductor, doubling the capacity; 20% or greater efficiency, and half as much thermal sag. Used commercially for 20 years, the conductors are deployed in over 60 countries across 5 continents. [1] They are available from multiple vendors and have been installed by utilities in a variety of climates, terrain types, and system configurations.

- **Superconducting transmission lines** use a class of metallic compounds that exhibit negligible resistance when cooled using liquid nitrogen, enabling very low losses and very high power-flow capacities. Superconductors have three key advantages over traditional conductors: they increase capacity 5-10 times at lower voltages, reduce substation build and cost, have no thermal sag (and line sag does not vary with ambient weather conditions or exposure to elements), and are at least 50% more energy efficient. Developed in the 1980s, superconductors have also been commercially deployed, with

[1] ACORE, Grid Strategies, *Unlocking the Grid: A Playbook on High Performance Conductors for State and Regional Regulators and Policymakers* (Oct. 2024), https://acore.org/wp-content/uploads/2024/10/Unlocking-the-Grid-A-Playbook-on-High-Performance-Conductors-for-State-and-Regional-Regulators-and-Policymakers.pdf ("HPCs Playbook"), at 2.

operational projects in the United States, Europe, and Asia over the past 20 years.[2] While superconducting technology has historically been used in specialized or urban settings due to its higher upfront costs, it is now increasingly viewed as a commercially viable solution for high-capacity, space-constrained corridors, particularly in urban areas and around substations.[3]

QUESTION 3: Please describe the primary benefits associated with your product(s)

1. **Increased capacity:** Both carbon/composite core conductors and superconductors offer substantial technical advantages over traditional aluminum conductor steel-reinforced (ACSR) and aluminum conductor steel-supported (ACSS) lines. One of the most important benefits is increased capacity. Carbon and composite core conductors can double the ampacity of an existing transmission line without requiring changes to the supporting structures. This is made possible by their lighter and stronger cores, which allow for a greater cross-sectional area of conductive aluminum. A 2024 GridLab and UC Berkeley study found that reconductoring with HPCs can add approximately four times the transmission capacity when compared to the current rate of new transmission development.[4] Superconducting cables add even more capacity: they can carry 5 to 10 times the power of a conventional conductor at the same voltage, enabling higher capacity transfers at lower voltages.[5] This is because superconductors have almost no resistance, allowing the conductor to carry high currents at low voltages with limited line losses. Superconductors can be used as high-capacity transmission in space-constrained or urban settings; when installed underground, superconductors can deliver three to ten times more capacity than traditional underground cables, making them especially well-suited for dense areas or constrained corridors.

2. **Improved energy efficiency:** HPCs also significantly improve the energy efficiency of the transmission system.[6] Carbon and composite core conductors can reduce line losses by 20% or more, resulting in measurable energy savings and lower

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[2] *Id*.

[3] ENTSO-E, Technopedia: High Temperature Superconducting (HTS) Cables (Mar. 2025), https://www.entsoe.eu//technopedia/techsheets/high-temperature-superconducting-cables/ (“Technopedia”).

[4] GridLab, *Reconductoring with Advanced Conductors Can Accelerate the Rapid Transmission Expansion Required for a Clean Grid* (Apr. 2024) https://www.2035report.com/wp-content/uploads/2024/06/GridLab_2035-Reconductoring-Technical-Report.pdf (“Reconductoring Technical Report”).

[5] *HPCs Playbook*, at 2.

[6] For additional specific examples of reducing line losses, *see HPCs Playbook*, at 11; *See also* CTC Global, *American Electric Power Doubles Capacity, Saves Time and Money*, (accessed Sept. 2024), https://ctcglobal.com/aep-reconductor-project/ (“CTC AEP Case Study”); *See also* CTC Global*, Tech Talk at NRECA Tech Advantage 2023* (Mar. 2023), https://ctcglobal.com/ctc-global-participates-at-techadvantage-2023/.

emissions over time. Superconductors offer even greater efficiency gains, reducing losses by 50-80%, because their resistance is near zero when operating at cryogenic temperatures.[7] This dramatically reduces the amount of electricity wasted during transmission and increases the value of delivered power, particularly over long distances. A 2022 ACORE and Grid Strategies report estimated that reconductoring with HPCs can prevent annual transmission losses of approximately 21 million megawatt-hours (MWh) and lower annual total system peak demand by 5.9 GW, generating over $2.2 billion in annual consumer savings at the national level.[8]

3. **Resilience (including extreme weather):** One of the most important benefits is improved resilience to extreme weather and environmental hazards. Both types of HPCs minimize thermal sag, which is a key constraint on traditional conductor performance. Carbon and composite core conductors exhibit approximately 50 percent less sag under high temperatures compared to traditional conductors, as they are mechanically stronger than traditional conductors. This helps maintain safe clearances from vegetation, built structures, and potentially wildfires,[9] enhancing both safety and reliability in regions prone to extreme heat or fire risk. Superconductors have no thermal sag at all and maintain consistent mechanical performance regardless of ambient weather conditions, since they are cooled and enclosed.[10] When installed underground, superconductors are shielded from wind, fire, ice, and debris, significantly improving operational reliability in both urban and rural settings.[11]

4. **Speed to deployment:** Another key operational advantage is the speed at which HPCs can be deployed. Reconductoring projects using carbon fiber or composite core conductors typically take between one and three years to complete, compared to seven to ten years for most new transmission lines.[12] This is primarily because HPC projects can be implemented within existing rights-of-way and often avoid the need for new land acquisition, lengthy permitting processes, or extensive environmental reviews. Even in rebuild scenarios where towers may need to be replaced to accommodate superconductors, the use of existing corridors streamlines construction timelines. This speed of deployment is critical

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[7] *Id.*

[8] *Reconductoring Technical Report.*

[9] *HPCs Playbook*, at 7.

[10] *Id.*

[11] For additional specific examples of resiliency, see *MDU Press Release; See also* CTC Global *SCE Press Release; See also* M. Ross, *Utility applications and experience with resilient electric grid systems utilizing high temperature superconductor wires in Chicago*, Science Direct Physica C: Superconductivity and its Applications, Volume 614 (Nov. 2023), https://doi.org/10.1016/j.physc.2023.1354374 ("AMSC"); *See also INL Report* at 158.

[12] U.S. Department of Energy*, Innovative Grid Deployment: Pathways to Commercial Liftoff, Interim Webinar Update* (Dec. 2023), https://www.energy.gov/sites/default/files/2023-12/Grid%20Liftoff%20Webinar%20Final.pdf ("Innovative Grid Deployment") at 19.

in the current context of rapidly increasing demand, interconnection backlogs, and climate-related threats to grid reliability.[13]

5. **Reduced land and visual impacts**: HPCs offer a lower-impact alternative to traditional transmission expansion by enabling utilities to upgrade existing corridors rather than acquiring new rights-of-way. Reconductoring projects minimize land disturbance and eliminate the need for extensive siting and permitting processes. Because these conductors are stronger and lighter, they can often be installed on existing towers, or if installed on new lines, require fewer or shorter towers than conventional alternatives—significantly reducing visual and environmental impacts. For example, Arizona Public Service was able to nearly double the capacity of a line without modifying its structures, eliminating the need for structure replacement or corridor expansion.[14] In another case, the Long Island Power Authority used superconducting cable to deliver 574 MW of capacity in a right-of-way just one meter wide.[15] These examples illustrate how HPCs support public acceptance and reduce barriers to timely project development.[16]

6. **Improved interconnection and curtailment outcomes**: By accelerating capacity upgrades in existing corridors, HPCs improve the ability of the grid to accommodate new generation and load.[17] Faster deployment (typically 1 to 3 years for reconductoring projects) helps clear interconnection backlogs and reduces costly curtailments. HPCs can relieve localized congestion and increase transfer capability across constrained interfaces, enabling more renewables and lower-cost power to reach load centers. The U.S. Department of Energy's (DOE) 2024 *Pathways to Commercial Liftoff: Grid Innovation* report found that deploying

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[13] For additional specific examples of speed to deployment, *see MDU Press Release; See also CTC AEP Case Study; See also CTC Global SCE Press Release.*

[14] Idaho National Laboratory, *Advanced Conductor Scan Report* (Dec. 2023), https://inl.gov/content/uploads/2024/10/23-50856_R12a_-AdvConductorsScanProjectReportCompressed.pdf ("INL Report"), at 131; See also CTC Global, Arizona Public Service Completes ACCC® Conductor Installation in Tempe, Arizona (Jul. 2020), https://ctcglobal.com/arizona-public-service-completes-accc-conductor-installation-in-tempe-arizona/ ("CTC Global Arizona Press Release").

[15] Advanced Energy United, *THIS IS ADVANCED ENERGY: High Temperature Superconducting Transmission* (Dec. 2016), https://blog.advancedenergyunited.org/this-is-advanced-energy-high-temperature-superconducting-transmission ("This is Advanced Energy").

[16] For additional specific examples of reduced land and visual impacts, *see INL Report at 131; CTC Global Arizona Press Release; See also* Transformer Magazine*, The Munich Superlink Project (2021),* *https://ivsupra.de/wp-content/uploads/2021/05/Transformer-Magazine_SuperLink-140521.pdf; See also This is Advanced Energy; See also ASMC.*

[17] For additional specific examples of improved interconnection and curtailment outcomes, *see MDU Press Release; See also Reconductoring Technical Report; See also* CTC Global*, SCE Uses ACCC® Conductor to Mitigate Sag and Increase Capacity (Mar. 2021),* *https://ctcglobal.com/sce-uses-accc-conductor-to-mitigate-sag-and-increase-capacity/, ("CTC SCE Press Release"); See also CTC Global Arizona Press Release; See also INL Report at 139.*

HPCs nationally can increase the capacity of the existing grid to support over 100 GW of incremental peak demand, which is enough to meet the North American Electric Reliability Corporation (NERC)'s estimated 10-year peak demand growth.[18] Another report estimated that reconductoring with HPCs would enable the integration of roughly 27 GW of additional generation capacity by replacing 5,000 miles of aging (50+ years old) transmission lines annually.[19] A 2024 GridLab and UC Berkeley study found that reconductoring with HPCs could account for roughly 80% of the transmission capacity needed to achieve 90% clean energy by 2035.[20]

7. **Cost savings:** The benefits described above allow High Performance Conductors (HPCs) to provide meaningful cost savings by allowing utilities to expand grid capacity using existing infrastructure.[21] Reconductoring with carbon or composite core conductors typically costs approximately 25 percent less than building new transmission lines, while still doubling the ampacity of the corridor.[22] These projects often avoid the need for new towers, foundations, and substation upgrades, reducing both capital and labor costs. Superconducting cables, though higher in upfront cost, can avoid costly voltage transformations and enable high-capacity delivery using existing lower-voltage infrastructure, yielding system-level savings in urban and space-constrained environments. A 2022 ACORE and Grid Strategies report found that reconductoring with HPCs has the potential to save consumers at least $140 billion over 10 years.[23] Similarly, a 2024 GridLab and UC Berkeley study found reconductoring with HPCs results in $85 billion in total savings by 2035 and $180 billion by 2050. These cost-savings are achieved by unlocking access to lower-cost, higher-quality generation in more locations across the country, thereby lowering wholesale electricity costs.[24] The study also found that pursuing widespread reconductoring with HPCs alongside development of new transmission lines without restrictions on transmission buildout can further yield significant cost savings of over $400 billion by 2050, over the business-as-usual case.[25]

QUESTION 4b: What is the typical deployment timeline for your solution from planning to operation?

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[18] U.S. Department of Energy, "Pathways to Commercial Liftoff: Innovative Grid Deployment," April 2024, https://liftoff.energy.gov/innovative-grid-deployment/ ("DOE Liftoff Report").
[19] *Advanced Conductors to Accelerate Grid Decarbonization,* at 19.
[20] *Reconductoring Technical Report.*
[21] For additional specific examples of cost savings, *see INL Report, at 143; See also MDU Press Release; See also CTC AEP Case Study; See also CTC SCE Press Release.*
[22] *Reconductoring Technical Report*, at 3.
[23] Grid Strategies, ACORE, *Advanced Conductors to Accelerate Grid Decarbonization* (Mar. 2022), https://acore.org/resources/advanced-conductors-on-existing-transmission-corridors-to-accelerate-low-cost-decarbonization/, ("*Advanced Conductors to Accelerate Grid Decarbonization*").
[24] *Reconductoring Technical Report,* at 7.
[25] *Id.*

Please see the response to Question 3 above on *Operational Benefits: Speed to Deployment.*

QUESTION 5: Where have your technologies been deployed to date?

- Carbon fiber / composite core conductors have seen robust global deployment, with over 125,000 miles worldwide, including countries such as Belgium, the Netherlands, Italy, India, and China,[26] while only about 10,000 miles have been deployed domestically.[27]

- Superconductors have seen robust global deployment across Chicago,[28] Long Island,[29] and several countries in Europe including Germany, Hungary, Norway, Belgium, Sweden, Spain, Denmark, Switzerland, France, United Kingdom and Italy.[30]

QUESTION 5a: Are there specific examples where your solution was deemed to be more cost effective than a traditional grid upgrade?

Please see the response to Question 3 above on *Commercial Benefits: Cost Savings*

Question 5b: Are there specific types of projects or system conditions where your technology is particularly valuable?

Please see the response to Question 3 above on *Commercial Benefits: Reduced Land and Visual Impacts*

Question 5c: Was the deployment subsidized by any government entities or others? If so, how important was this support to deployment?

Federal support—particularly through the U.S. Department of Energy's Grid Resilience and Innovation Partnerships (GRIP) program—has played an important role in accelerating the deployment of High Performance Conductors (HPCs). GRIP grants help de-risk projects and overcome barriers to adoption by supporting utilities with deployment costs, technical assistance, and planning resources.

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[26] *Reconductoring Technical Report*, at 42.
[27] *HPCs Playbook.*
[28] *AMSC.*
[29] Nexans, *Superconductors for Electricity Grids* (2022), https://www.nexans.com/app/uploads/2024/01/superconductors-for-electricity-grids-nexans-white-paper-2022.pdf, at 20.
[30] *Technopedia.*

The National Association of Regulatory Utility Commissioners (NARUC) has recognized the value of this support. At its 2024 Annual Meeting, NARUC adopted a resolution urging continued federal funding for systemwide deployment of Advanced Transmission Technologies (ATTs), which includes HPCs. The resolution highlights both the technical potential and ratepayer benefits of these solutions and encourages Congress to sustain funding beyond the expiration of the Infrastructure Investment and Jobs Act in 2025.[31]

Question 6: What, if any, adoption barriers has your company encountered?

1. **Current incentives do not encourage maximizing power in existing rights-of-way using carbon / composite core conductors:**
    a. Most utilities earn revenue from a return on new capital investments and can increase their revenue through spending on more capital-intensive projects, such as new generation or transmission, or distribution lines and related equipment. This model made sense when the utility industry was forming, and policymakers wanted to incentivize the expansion of the power system to ensure residential, commercial, and industrial customers received service. This means utilities have historically added new transmission capacity to the grid by building new transmission lines or rebuilding existing lines to higher voltages. Reconductoring has generally been reserved for replacing aging transmission lines, and given an equal choice, a utility would make more money building a new line over reconductoring with carbon / composite core conductors if both added the same amount of grid capacity.
    b. Separately, utilities have generally addressed transmission line maintenance and replacement independent of planning for transmission capacity expansion, and due to differences in upfront costs, there is typically less regulatory resistance to replacing an aging line with the same, newer conductor, known as "in-kind replacement." For these reasons, utilities may be more hesitant to replace or reconductor aging lines with HPCs if those projects are met with more skepticism from regulators, cannot be approved due to "least cost" requirements, or the utility cannot demonstrate immediate need for the additional capacity. Furthermore, utilities are rightfully focused on reliability, but that emphasis may lead risk-aversion and a preference for status quo technologies.

2. **Regulators may be required to only consider lowest upfront costs**: State utility regulators are economic regulators tasked with monitoring utilities to ensure they don't overinvest in capital projects at the expense of customers. The financial

[31] NARUC, *Resolutions Passed by the NARUC Board of Directors at the November 10-13, 2024 NARUC Annual Meeting and Education Conference In Anaheim, California* (Nov. 2024), https://pubs.naruc.org/pub/812873F4-E348-B77F-4D75-E513FF13A86D?_gl=1*1dz94t4*_ga*MjYwNzQwOTc5LjE3MTc0MjMzMzQ.*_ga_QLH1N3Q1NF*MTczMTYxMDU1MS4xMy4wLjE3MzE2MTA1NTEuMC4wLjA.

incentive for utilities to potentially overinvest in the system is known as "gold-plating" and has led to requirements or a focus on the lowest upfront capital cost solutions, rather than considering longer-term net-benefits for customers. For reconductoring on existing structures, HPCs do provide the lowest capital cost solution per megawatt of power delivered, even if other benefits are ignored. HPCs may have a higher upfront cost compared to use of traditional conductors for rebuilding or new line projects, but almost always have greater long-term cost savings for customers. However, regulators may not accept such investments for utilities as HPCs may be viewed as "gold-plating." With FERC Order No. 1920, the utilities are now required to consider 7 benefits over a long-term total life cycle analysis when considering project net life-cycle costs. This will more accurately compare project conductor choices and the total benefits and costs for consumers.

3. **Insufficient information limits understanding of HPCs:** The number and type of advanced technologies on the distribution side has significantly increased over the past 20 years. Given the host of advanced technologies now available for deployment, utilities and regulators are faced with the challenge of identifying optimal solutions given the different benefits, costs, and uses of each technology. New technology adoption often requires development of new processes and education for planners, engineers, and regulators. While HPCs are not new to utilities, planners and engineers may need to update planning models with correct conductor technical specifications and costs. Regulators and policymakers also need access to information about the additional benefits and costs of HPCs.

4. **Current planning and permitting models do not holistically incorporate HPCs:** Current transmission planning frameworks often fail to fully incorporate HPCs as viable system expansion options. Asset replacements, such as reconductoring, are typically treated as engineering decisions made after the formal planning process, rather than as integrated solutions within the broader set of transmission alternatives. As a result, planning models frequently overlook the full range of benefits HPCs can provide—including improved reliability, faster deployment, increased efficiency, and reduced permitting risk. FERC Order No. 1920 marks an important step forward by requiring transmission planners to evaluate regional and interregional solutions—including those that use existing rights-of-way. This opens the door for reconductoring projects using HPCs to be considered alongside new lines, rather than being excluded due to narrow planning scopes focused solely on greenfield expansion. However, implementation will require deliberate efforts by planners and stakeholders to ensure that reconductoring options are meaningfully analyzed in needs assessments, scenario modeling, and benefit-cost evaluations. On the permitting side, while reconductoring can often avoid the full permitting burden of new transmission lines, that is not guaranteed. Many existing lines were built before modern environmental regulations, and any substantial upgrade—including

reconductoring or tower rebuilds—may trigger new environmental review requirements. These permitting uncertainties can erode the speed advantage of reconductoring. The DOE took a step to address this in 2024 by approving a Categorical Exclusion to National Environmental Policy Act (NEPA) to streamline the permitting process for reconductoring and rebuild projects subject to DOE authority.

MA DPU (D.P.U. 25-69) questions for GETs companies:

1. **Please describe any advanced transmission or distribution technologies your company offers.**

VEIR is a Massachusetts company developing the next generation of superconducting electric transmission lines that operate with 5-10 times the transfer capacity of conventional lines at a given voltage level. VEIR lines can both greatly increase the transfer capacities in existing transmission corridors (both underground and overhead) and greatly reduce the space required for new corridors, reducing the burden of siting/permitting requirements and right-of-way acquisition.

The principal innovative hardware components of the VEIR superconducting system include:

(1) The conductor assembly housing the superconducting cable and the liquid nitrogen (LN) coolant that flows along the length of the line.
(2) The superconducting cable sitting within the conductor assembly that carries the electrical current. VEIR uses a superconductor called rare-earth barium copper oxide (ReBCO) that contains small quantities of either the element yttrium (Y) or gadolinium (Gd). ReBCO tapes are readily available from a growing number of vendors globally.
(3) Proprietary heat exchanger units that passively re-cool LN flowing inside the line in a distributed fashion along the entire length of the line. The heat exchanger units are positioned about 1 kilometer apart along the length of the line.
(4) Liquid nitrogen infrastructure that ensures the reliable supply of LN to the line at controlled temperatures and pressures. LN infrastructure includes industry-standard LN storage, pressurization, cooling, and pumping equipment, all of which can be operated remotely.

   a. What is the current technology readiness level of your product(s)?

VEIR's system is currently at TRL-7.

   b. Is/are the product(s) commercially available?

VEIR's system is currently in the process of being commercialized, with several active commercial discussions underway.

VEIR has conducted an outdoor, energized demonstration at their Massachusetts test facility in 2023. The company has been awarded projects from both NYSERDA and ARPA-E and was selected for negotiations for a DOE GRIP award (negotiations pending) for a commercial interconnection line.

2. **Please describe the primary cost categories and amounts associated with your product(s).**
    a. What are the typical installation costs for your technology (per mile, per site, per kilowatt/megawatt, or as applicable)?

At scale, VEIR's overhead AC transmission line products will operate at voltages up to 230 kV with rated capacities of 2,400 MVA. Those subsequent products will be deployed with a capital cost that is 50%+ lower than conventional XLPE transmission lines, dependent on the specific application.

    b. What are the expected operations and maintenance costs over the technology's useful life?

For the 230 kV line configuration, VEIR anticipates O&M costs for both overhead and underground applications to be comparable to those of conventional underground transmission lines, which also have active cooling systems. VEIR's O&M costs are expected to be driven largely by the cost of liquid nitrogen for the open-loop, evaporative cooling system.

    c. What factors most strongly affect the cost effectiveness of your technology?

A key component in VEIR's system is high-temperature superconducting (HTS) tape. HTS tape is produced by numerous domestic and international manufacturers. The supply of HTS tape is rapidly expanding to serve several markets, including fusion reactors, power lines, and other applications. During the 2020s, prototype fusion reactors alone have required a 10-fold increase in HTS supply, which has subsequently catalyzed manufacturing advances that deliver increasing volumes at lower costs; a trend which VEIR is able to benefit from.

3. **Please describe the primary benefits associated with your product(s).**
    a. What are the technical, operational, and commercial benefits of your technology?

VEIR's technology excels when existing transmission corridors need large transfer capacity upgrades and when there are space constraints for new corridors. VEIR lines also add grid capacity without triggering as many or as onerous and time-consuming siting and permitting requirements as conventional lines. VEIR lines are applicable to all forms of transmission, including the high-voltage transmission grid, data center and large electrical load integration, and generation interconnection tie-lines.

Traditionally, when utilities needed to increase capacity, they would rebuild an existing corridor using a higher-voltage conductor, which would require the installation of additional transformers, or in some cases new high-voltage substations. However, replacing conventional conductors with superconductors provides several benefits, particularly for corridors that are in urban areas where construction and access to the conductor are very challenging.

Upgrading to a superconductor allows for:

- **Higher capacity transfers at lower voltages.** Superconductors have no resistance which allows the conductor to carry high currents at low voltages with limited line losses. Superconductors can add 5-10 times more capacity at the same voltage as a conventional conductor.
- **Avoided upgrades and reuse of existing infrastructure.** Because superconductors can operate at lower voltages it helps avoid the need for costly and difficult voltage upgrades in substations and the need for new transformers that would traditionally be needed to add new capacity. Superconductors are also more compact than conventional conductors, which allows for easier and less costly installation in crowded urban infrastructure, and often allows reuse of existing low- or medium-voltage corridors, infrastructure, or underground conductor ducts.
- **Minimized impacts on surroundings.** Superconductors have almost no external magnetic fields and are cooled. These properties minimize the impact on surrounding electronic and communication systems and result in no thermal restrictions on their placement underground, as well as no thermal requirements to allow spacing between phases. This reduces the space required for installation and eliminates the overheating related failures associated with conventional underground conductors.

b. Does your technology support broader public policy goals including, but not limited to, the integration of clean energy, emissions reductions, grid resilience, or cost savings for customers and ratepayers?

VEIR's technology supports numerous Massachusetts' public policy goals including integration of clean energy, emissions reductions, resilience, and cost savings, while also minimizing impacts of new infrastructure on local communities.

VEIR's advanced conductor technology offers much higher transfer capacities compared to conventional conductors, at a given voltage level. This feature enables renewable developers to build projects that would be infeasible with conventional conductors due to land and interconnection capacity constraints.

In addition to driving system emissions reductions by integrating more clean energy, VEIR's superconductors also increase the efficiency of the power system. Superconducting lines operate with negligible line losses, making them 50-80% more energy efficient than conventional transmission lines, leading to both emissions and cost savings.

Long-distance superconducting power lines, only possible today through VEIR's innovative approach, can also unlock new capacity within the transmission network by increasing the transfer capacities of existing corridors by a factor of at least 5. Being able to deploy such large capacity increases in existing corridors supports improved grid reliability and resilience by increasing transfer capacity headroom in the network, allowing for additional contingency power flow pathways to stabilize the grid in the face of system disturbances.

Finally, by enabling high-capacity, lower-voltage lines, VEIR can materially reduce the impacts to communities and the environment that result in lengthy permitting and siting processes for high-voltage projects. This is especially the case in areas with heightened land-use sensitivities, including urban centers and environmental justice communities. VEIR's technology provides a pathway to add transmission capacity where it is most needed—without exacerbating existing infrastructure burdens.

4. **Does your technology integrate with existing grid infrastructure and utility operation systems?**
    a. Are there unique requirements required to operationalize your technology (e.g., siting and permitting, workforce training, operability with utility systems, etc.)?

The VEIR superconductor system utilizes standard structures/trenching and standard substation terminal equipment, and as such, it is compatible with existing utility systems. VEIR's cooling system utilizes liquid nitrogen which is a common industrial gas, and makes up 78% of earth's atmosphere. Typically, no additional permitting is required for the use of this gas, as nitrogen is a non-toxic, non-warming and inert.

Because VEIR's systems carry more power at a given voltage, they can reduce permitting requirements. VEIR's lower voltage lines are able to go through more streamlined permitting processes relative to the conventional lines, as these conventional lines would be at higher voltages to carry the same amount of power, and therefore be subject to more onerous permitting requirements.

    b. What is the typical deployment timeline for your solution from planning to operation?

VEIR's deployment timelines are consistent with conventional transmission projects, ranging from 3-6 years, inclusive of the planning process, depending on the complexity and nature of the project being proposed. Higher voltage regional projects going through the ISO planning process will typically take more time, as opposed to local upgrades or rebuilds, which can be undertaken on an expedited timeline.

c. Do you offer support or training for utilities to assist with the deployment and operation of your technology?

Yes. VEIR is currently working with a partner utility under a NYSERDA grant to co-develop maintenance and installation procedures for overhead superconducting lines. These procedures will be made available to additional utilities seeking to deploy VEIR's lines.

Additionally, VEIR will provide ongoing operational support to ensure the reliable operation of the lines and associated infrastructure, including nitrogen cooling system.

5. **Where have your technologies been deployed to date?**
    a. Are there specific examples where your solution was deemed to be more cost effective than a traditional grid upgrade?

VEIR's initial deployments are occurring in projects where traditional grid upgrades are not an option for execution.

b. Are there specific types of projects or system conditions where your technology is particularly valuable?

VEIR's technology is particularly valuable where moving large amounts of power through constrained areas is required. This manifests in several scenarios such as a powerline rebuild in a transmission ROW that cannot be expanded due to the surrounding environment or community, or a renewable energy interconnection where land for a solar or wind development is available, but the available corridors for transmission infrastructure are limited.

VEIR has also seen increasing interest in application of the technology for underground infrastructure, where the costs of trenching and burying conventional infrastructure can be greatly reduced by instead using a much smaller superconducting line.

c. Was the deployment subsidized by any government entities or others? If so, how important was this support to deployment?

VEIR's work is primarily investor funded but has also received federal and state funds for an ARPA-E research project, as well as funds from NYSERDA for a project developing installation and operations procedures for overhead superconductor infrastructure. In October 2024, VEIR was selected to negotiate a $30 million award through the United States

Department of Energy's Grid Resilience and Innovation Partnerships (GRIP) Smart Grid Grants Program. This project, which is still under negotiation, is to design and construct a generation tie-line for new solar photovoltaic installation in Michigan

6. **What, if any, adoption barriers has your company encountered?**
    a. Are there specific barriers that currently limit the use of your technology in Massachusetts relative to other jurisdictions?

VEIR is not aware of any MA specific barriers compared to other jurisdictions.

    b. Please describe your experience in working with utilities or government entities in Massachusetts and/or other jurisdictions.

VEIR has experience working with regulated electric utilities, including an early partnership with National Grid, on product development and pilot deployment projects across the northeast United States. Additionally, VEIR is experienced in engaging with government funding organizations in Massachusetts, as well as numerous other states and at the federal level.

    c. Do you have any recommendations or considerations on how to facilitate cost-effective and timely adoption of advanced grid technologies?

Utilities are rightfully focused on reliability, but that emphasis can make them overly risk-averse and create a preference for status quo technologies. There are very few incentives for utilities to innovate on the grid on behalf of customers, though the advanced transmission technology legislation passed in last year's climate bill is helping to change that.

In current transmission planning paradigms, asset replacements are not generally integrated into broader planning for transmission expansion. Within transmission planning and development, decisions regarding conductors are often considered an engineering choice that occurs after planning. Utilities have generally addressed transmission line maintenance and replacement independent of planning for transmission capacity expansion, and due to differences in upfront costs, there is typically less regulatory resistance to replacing an aging line with the same, newer conductor, known as "in-kind replacement." For these reasons, utilities may be more hesitant to replace or reconductor aging lines with a superconductor if there is the potential for those projects to be met with more skepticism from regulators, cannot be approved due to "least cost" requirements, or the utility cannot demonstrate immediate need for the additional capacity.

In addition, state utility regulators are economic regulators tasked with monitoring utilities to ensure they don't overinvest in new capital projects at the expense of customers. The financial incentive for utilities to potentially overinvest in the system is known as "gold-plating" and has led to requirements or a focus on the lowest upfront costs solutions, rather than considering longer-term net-benefits for customers. Superconductors may have a higher upfront cost compared to traditional conductors but often have greater long-term cost savings for customers. However, regulators may not accept such investments for utilities as use of a superconductor may be viewed as "gold-plating."

Ensuring that utilities know the DPU is expecting and will be supportive of incorporation of advanced grid technologies, including superconductors, into their transmission plans is critical to facilitating cost-effective and timely adoption of advanced grid technologies. In addition, regulators can make it clear they expect advanced grid technology solutions not just be a box checking exercise when utilities come before the Commission, but that advanced grid technologies are included early in solutions developed along with robust analysis of the long-term benefits and costs for deploying advanced grid technologies compared to alternatives. The advanced grid technology requirements passed in last year's climate bill and this docket opened by DPU are excellent first steps.

VIA ELECTRONIC MAIL
July 3, 2025
Andrew Strumfels, Hearing Officer
Massachusetts Department of Public Utilities
andrew.w.strumfels@mass.gov

Re: Investigation by the Department of Public Utilities on its Own Motion into the Use of Advanced Conductors, Grid-Enhancing Technologies, and Other Advanced Transmission Technologies to Enhance the Performance of the Commonwealth's Transmission System in Applications that are Subject to Federal Jurisdiction (D.P.U. 25-69)

Dear Hearing Officer Strumfels:

Advanced Energy United submits for filing the attached comments in response to the June 2nd Vote and Order Opening Investigation issued in D.P.U. 25-69.

Respectfully submitted,

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Advanced Energy United Comments

Re: Investigation by the Department of Public Utilities on its Own Motion into the Use of Advanced Conductors, Grid-Enhancing Technologies, and Other Advanced Transmission Technologies to Enhance the Performance of the Commonwealth's Transmission System in Applications that are Subject to Federal Jurisdiction (D.P.U. 25-69)

Introduction

Advanced Energy United ("United") appreciates the opportunity to submit comments in response to the Massachusetts Department of Public Utilities' ("Department") Vote and Order Opening Inquiry in D.P.U. 25-69. We commend the Department for initiating this critical investigation, pursuant to Section 121 of An Act Promoting a Clean Energy Grid, Advancing Equity, and Protecting Ratepayers (St. 2024, c. 239), into the potential deployment of advanced conductors, grid-enhancing technologies ("GETs"), and other advanced transmission technologies ("ATTs") to optimize the Commonwealth's transmission system. For the purposes of these comments, references to ATTs or GETs include ATTs, GETs, and advanced conductors.

United strongly supports the Department's exploration of these technologies, which offer significant opportunities to improve the efficiency, affordability, and reliability of the electric grid. Our comments below demonstrate how these technologies can alleviate transmission congestion, accelerate the integration of clean energy, reduce ratepayer costs, and enhance system resilience.

United is a national association of businesses that works to accelerate the move to 100% clean energy and electrified transportation in the U.S. The term advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting our energy needs today and tomorrow. These include electric vehicles ("EVs"), energy efficiency, demand response ("DR"), energy storage, solar, wind, hydro, nuclear, heat pumps (air- and ground-sourced), and smart grid technologies. United represents more than 100 companies in the $374 billion U.S. advanced energy industry, which employs 4.1 million U.S. workers and over 136,200 in the Commonwealth of Massachusetts.

Policy and Regulatory Recommendations

We encourage the Department to take the following actions as part of D.P.U. 25-69:

- Require utilities to evaluate and incorporate ATTs as part of all major transmission planning and upgrade proposals, especially where congestion or interconnection backlogs exist.
- Ensure that benefit-cost analyses reflect the full range of reliability, resilience, and emissions reduction benefits associated with these technologies.
- Establish a transparent reporting mechanism to track utility deployment of ATTs and their cost-effectiveness.
- Explore pilot programs and cost recovery pathways to accelerate the adoption of promising technologies.

The Role of Advanced Transmission Technologies in Grid Optimization and Congestion Relief

ATTs offer utilities affordable, near-term solutions to optimize the performance of existing infrastructure and alleviate grid congestion. Like DR and flexible interconnection, which are cost-effective tools to avoid or defer the need for distribution system upgrades, ATTs enhance power system flexibility, reduce the curtailment of renewables, and provide a scalable alternative to costly transmission infrastructure investments. Key technologies include:

- **Dynamic Line Ratings ("DLR"):**
    - Uses real-time weather and environmental data to determine the actual thermal capacity of transmission lines.
    - Typically unlocks 20–40% more capacity compared to static ratings.
    - Helps operators avoid unnecessary curtailments and increases utilization of existing infrastructure.
    - Enables better system visibility and supports asset health monitoring.
- **Advanced Power Flow Controllers ("APFCs"):**

- Actively control the direction and magnitude of power flows.
    - Allow grid operators to reroute electricity to underutilized lines, easing bottlenecks.
    - Improve overall system flexibility and reduce congestion costs.
- **Topology Optimization (“TTO”):**
    - Software-driven system that identifies optimal grid configurations under various operational conditions.
    - Helps prevent overloads, improves reliability, and identifies cost-effective solutions to operational constraints.
    - Supports grid operators in mitigating reliability risks in real time.
- **Reconductoring with Advanced Conductors:**
    - Reconductoring is the act of replacing conventional wires on existing towers with conductors that can carry significantly more current.
    - Can double the capacity of existing lines without expanding rights-of-way.
    - Offers deployment timelines of 1–3 years, compared to 7–10 years for new lines.
    - Provides up to 4x more transmission capacity than current reconductoring rates and can meet up to 80% of grid expansion needs for a 90% clean energy future.

Together, these technologies form a critical toolkit for meeting growing electricity demand and integrating low-cost clean energy while avoiding or deferring new infrastructure buildout.

Cost Savings and Economic Benefits for Ratepayers

Numerous studies show that adopting ATTs results in material cost savings for consumers. According to the study, “Unlocking the Queue", ATTs could reduce grid congestion by over 40%, which would have saved U.S. ratepayers between $4 and $8 billion annually over the past five years. The same study estimated $5 billion in annual energy cost savings nationwide, with payback periods as short as six months. These benefits are not hypothetical:

during the 2018 "bomb cyclone" event, ISO-NE successfully deployed DLR to avoid significant congestion costs, demonstrating real-world applicability in the Northeast[1] [2]

Similarly, reconductoring with advanced conductors can double line capacity at approximately half the cost of building new lines. A 2024 report by the American Council on Renewable Energy ("ACORE") found that replacing aging lines with advanced conductors could quadruple grid capacity additions compared to current rates of new build-out, enabling the integration of 27 GW of new generation per year if just 25% of lines slated for replacement were upgraded in this way.[3]

Case Studies Demonstrating Value and Feasibility

- **ComEd Case Study (Illinois):** RMI examined delays in connecting new generation due to interconnection backlogs. Traditional upgrades were projected at $100 million and three years. GETs provided an alternative at $12 million and 12-15 months.[4]
- **Five-State Midwestern Analysis**: A study covering Illinois, Indiana, Ohio, Pennsylvania, and Virginia found that deploying a suite of three ATTs would cost $100 million and yield $1 billion in annual production cost savings.
- **Texas and Kansas GETs Deployments**: DLR and APFCs have been deployed in Texas and Kansas to manage congestion and reduce stress on system assets. In Kansas, the deployment of GETs led to production cost savings of $175 million annually, with a capital

[2]Utility Dive, Grid operations technologies protected customers from the bomb cyclone, (Feb. 14, 2018) https://www.utilitydive.com/news/grid-operations-technologies-protected-customers-from-the-bomb-cyclone/516799/

[3]AMP Coalition and Grid Strategies, Unlocking the Grid: A Playbook on High Performance Conductors for State and Regional Regulators and Policy Makers (Oct. 2024) https://acore.org/wp-content/uploads/2024/10/Unlocking-the-Grid-A-Playbook-on-High-Performance-Conductors-for-State-and-Regional-Regulators-and-Policymakers.pdf

[4]RMI, Getting Interconnected in PNJM: Gird-Enhancing Technologies (GETs) Can Increase the Speed and Scale of New Entry from PNJM's Queue, RMI, (Feb. 2024) https://rmi.org/wp-content/uploads/dlm_uploads/2024/02/GETs_insight_brief_v3.pdf

investment of only $90 million, effectively paying for itself within six months (WATT Coalition, 2021).[5]

Conclusion

Massachusetts faces increasing demand for clean, reliable, and affordable electricity. As transmission congestion and resource integration challenges grow, ATTs provide a vital toolkit for achieving the Commonwealth's climate, equity, and affordability goals. United commends the Department for opening this inquiry and urges the integration of these technologies into utility practices and planning processes moving forward.

We appreciate the opportunity to submit these comments and look forward to continued engagement.

[5] WATT Coalition, Unlocking the Queue: Summary of the Report Findings (Feb. 24, 2021) https://watt-transmission.org/unlocking-the-queue/

Comments of the WATT Coalition to the Commonwealth of Massachusetts Department of Public Utilities, in response to questions from June 2, 2025 on Advanced Transmission Technologies

D.P.U. 25-69

Submitted July 3, 2025

Introduction

The WATT Coalition is pleased to submit comments to the Massachusetts Department of Public Utilities ("DPU"), to supplement responses by utilities and Grid Enhancing Technology ("GETs") vendors. These comments collect examples from across the world that show how GETs can achieve many of the goals of the legislation that the DPU is charged with implementing:

- access to lower cost and zero carbon electricity;
- reduced generator curtailment or congestion;
- reduced environmental impacts;
- maximization of the value of planned investments;
- improved resilience; and
- improved outage coordination and mitigation.

Massachusetts utilities are well-positioned to move forward with GETs deployment. National Grid has already had significant experience with Dynamic Line Ratings ("DLR"), with successful case studies going back to 2021.[1] Eversource is collaborating with the University of Connecticut to evaluate DLR for offshore wind integration.[2] However, these initial steps are insufficient to fully realize the benefits of GETs for ratepayers. Utilities must fully evaluate and implement GETs as solutions for reliability, policy and economic goals to ensure that their investments are prudent and that electric rates are just and reasonable.

Specific Questions

B.1.b Provide a list of the transmission and distribution technologies that the Company considers mature, commercially available, and ready for integration into utility planning and grid operations.

WATT's membership includes Grid Enhancing Technology companies with commercialized products:

- Transmission Topology Optimization (TTO) finds reconfigurations for the grid that can prevent curtailment of low-cost generation, and address planned or unplanned outages.
  - Member vendor:: NewGrid Inc.

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[1] Marmillo, J., et al. "An Empirical Analysis of the Operational Efficiencies and Risks Associated with Static, Ambient Adjusted, and Dynamic Line Rating Methodologies." *2021 Next Generation Network Paper Competition*, 2021, https://cigre-usnc.org/wp-content/uploads/2021/11/An-Empirical-Analysis-of-the-Operational-Efficiencies-and-Risks-Associated-with-Line-Rating-Methodologies.pdf.

[2] Severance, Jaclyn. "UConn Receives Department of Energy Grant Supporting Offshore Wind Grid Integration." *UConn Today*, 20 Nov. 2023, https://today.uconn.edu/2023/11/uconn-receives-department-of-energy-grant-supporting-offshore-wind-grid-integration/.

- Advanced Power Flow Control (APFC) can help implement reconfigurations, and push or pull power over different circuits such that all assets are used safely and efficiently.
    - Member vendor: Smart Wires Inc.
- Dynamic Line Ratings (DLR) measure true capacity of transmission lines to make full use of existing infrastructure.
    - Member vendors: Ampacimon, LineVision, Lindsey Systems, Heimdall Power, Prisma Photonics

These technologies share challenges when it comes to utility adoption. To be fully implemented, they require most utilities to undertake internal technical and process changes. Efficient use of grid assets is not traditionally part of utility infrastructure or operations planning. When technologies were not available to measure line capacity or direct power flow, this made sense. Now, these technologies have been commercialized for 10-20 years. Their capabilities have improved while they have become more affordable. Today, even the most proactive U.S. adopters are lagging far behind utilities in Europe,[3] the Middle East, Australia,[4] and South America.[5] In 2021, experts at a FERC technical conference identified that the main obstacle to GETs deployments in the United States was a lack of incentive for utilities to deploy grid efficiency technologies.[6]

We commend the leaders in Massachusetts for working to identify the opportunities and obstacles for these technologies. The benefits to ratepayers from full integration of these technologies will be significant, as we detail below.

B.2.a a. Under what circumstances (e.g., load conditions, network congestion, geographic area) would these technologies be more cost effective than conventional transmission or distribution upgrades?

The WATT Coalition advocates for the use of GETs on the transmission grid rather than the distribution grid, because the potential cost savings are much clearer and more transparent. However, some of our members have deployed on sub-transmission lines and there will be more applications on the distribution grid as utilities develop digital twins and other tools to monitor the distribution grid and identify needs.

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[23] See examples in "Technopedia: Showcase of Grid Enhancing Technologies," ENTSO-E, June 2021, https://www.entsoe.eu/events/2021/06/29/webinar-on-grid-enhancing-technologies/

[4] See, e.g., Carroll, David, "Australian grid operator turns to Smart Wires technology to unlock renewables," PV Magazine, September 16, 2022, https://www.pv-magazine.com/2022/09/16/australian-grid-operator-turns-to-smart-wires-technology-to-unlock-renewables/

[5] See also "A Guide to Case Studies of Grid Enhancing Technologies," Idaho National Lab, October 2022, https://inl.gov/wp-content/uploads/2023/03/A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf which features both modeling and physical deployments.

[6] See testimony from the Federal Energy Regulatory Commission's September 10, 2021 Workshop to Discuss Certain Performance-Based Ratemaking Approaches, https://www.ferc.gov/news-events/events/workshop-discuss-certain-performance-based-ratemaking-approaches-09102021

In some cases, GETs can be used in place of traditional transmission grid upgrades. In the UK, where National Grid UK is incentivized to lower infrastructure costs,[7] they have used DLR to unlock one gigawatt of additional transfer capacity[8] and APFC to unlock two gigawatts.[9] When GETs solve a problem, they should be cheaper than the traditional solution by definition. However, they are not applicable for every grid constraint.

GETs are not always a permanent replacement for new transmission lines, but they serve other important roles in lowering consumer costs. These benefits are discussed in detail in "Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts,[10]" and are summarized below:

1. GETs reduce congestion costs. By increasing the capacity of the existing system, the existing poles and wires can deliver the cheapest generation more often. Before construction, GETs can reduce congestion by 40% or more, and can be deployed in weeks or months, with little or no outage time.
2. GETs create more room on the grid for new energy resources and for new load. New generation will need to interconnect quickly to meet forecasted load growth from industry and electrification. The speed of deployment is an important value of GETs in this context, where traditional grid upgrades can take years to plan, permit and build.
3. GETs optimize existing transmission lines to be used to their full capacity, avoiding or delaying costly upgrades or rebuilds. By considering GETs, planners can identify which lines truly need to be fully rebuilt, saving money on lines that can be salvaged with GETs and increasing the overall value of any transmission investments.
4. GETs can reduce constraints while transmission lines are under development and construction, a process that often takes years and leads to disruptive medium-term outages. With GETs in service on a much faster timeline than new transmission, generation or load projects can proceed while construction is underway. Interruptions of service that come with reconductoring, rebuilding, or building new transmission lines can be reduced through applications of GETs such as rerouting power along alternative circuits with Advanced Power Flow Control or Topology Optimization or increasing the capacity of other lines with DLR.

Other benefits of GETs are less quantifiable, but still important. GETs support operator decision-making by serving as tools to maintain reliability: GETs measure capacity, control grid use, and

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[7] Tsuchida, Bruce T., and Rob Gramlich, "Improving Transmission Operation with Advanced Technologies: A Review of Deployment Experience and Analysis of Incentives" at 23, June 24, 2019 https://watt-transmission.org/wp-content/uploads/2019/06/brattle-grid-strategies-paper-improvingtransmissionoperationwithadvancedtechnologies.pdf
[8] See How Dynamic Line Ratings Accelerated Renewable Energy Integration, LineVision Inc., March 14, 2024, https://www.linevisioninc.com/news/how-dynamic-line-ratings-accelerate-renewable-energy-integration
[9] See "National Grid: Northern England Projects," Smart Wires Inc., April 4, 2024, https://www.smartwires.com/2024/04/02/national-grid-northern-england-projects/
[10] Tsuchida, Bruce T., Linquan Bai, Jadon M. Grove, ""Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts," The Brattle Group, April 20, 2024 https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf

identify options for how power could flow on the grid. The information and data from GETs allow operators to use infrastructure differently, which can protect the grid and ensure continuous service to customers. Operators can also use the grid more flexibly with GETs. With improved visibility and control from GETs, a utility might redirect power flow to prevent icing or reduce risks of outages with topology optimization or advanced power flow control. Grid operators might avoid rolling blackouts during a cold snap because DLR data allows them to send more power down their lines.

Outage mitigation with GETs often enhances reliability while also reducing costs, as the examples below demonstrate:

a. Colombia: APFC was used to mitigate an outage, saving $70M+ over a 3.5 year outage period. The savings induced by avoiding redispatch were estimated to be over $20.5 million a year, while the annual costs of the modular FACTS devices were estimated to be between only $1.5 million and $4 million.[11]

b. Minnesota: MISO implemented a reconfiguration solution to mitigate costs from a major transmission outage, saving ~$40M over a nine-month period by successfully and reliably increasing throughput by up to 56% in the area.[12]

c. Northeast US: ISO-NE was able to avoid significant congestion costs during the 2018 “Bomb Cyclone” by leveraging weather-adjusted line ratings to increase their transmission line ratings to allow more power to flow.[13]

B.2.b Can these technologies help to avoid or delay the need for building new power lines or substations? Please explain your answer.

In some cases, GETs may be an alternative to transmission expansion and reinforcement, as discussed above. Using GETs as bridge solutions while new infrastructure is planned and permitted can also preserve optionality; if a grid need does not materialize on the expected timeline, the larger scale project may not be needed. However, most new transmission projects are needed far before they come into service.[14] GETs may be most helpful for planning asset maintenance projects. DLR sensors, for instance, can determine whether a line is in good condition or if it needs to be replaced in part or in whole. VELCO is using APFC to extend the life of a more expensive grid asset, which avoids a larger infrastructure investment.[15]

See other examples of delayed or avoided infrastructure investments with GETs:

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[11] Ibid.
[12] Ibid.
[13] Ibid.
[14] St. John, Jeff, “The US is building power lines faster, but not fast enough,” Canary Media, September 18, 2023, https://www.canarymedia.com/articles/transmission/the-us-is-building-power-lines-faster-but-not-fast-enough
[15] Sandbar Station SmartValve Project, VELCO, https://www.velco.com/sandbar

i. Texas: AEP installed real-time line ratings on a congested 138 kV transmission line to avoid a $20 million upgrade that would have quickly become a stranded asset as new lines were built to serve increased wind generation.[16]

ii. Pennsylvania: PPL Electric Utilities deployed DLR for less than $1 million, compared to $20 million for reconductoring, and $40 to $60 million for rebuilding transmission. DLR would also be operational in less than 1 year with no outages, compared to 2 to 3 years with extended outages for reconductoring, and 3 to 5 years with extended outages for rebuilding transmission.[17]

iii. New York: A DLR project upstate will avoid the need to rebuild 26 miles of transmission lines. With an estimated cost of $3.2 million, the project budget is less than the average cost of rebuilding just a single mile of a 115 kV line in the area.[18]

B.2.c Generally, do these technologies support Massachusetts climate goals and clean energy objectives? Please explain your answer.

The benefits to Massachusetts's climate goals can be extrapolated from studies of other regions. In a study of PJM's interconnection queue, RMI found that GETs could enable interconnection for 6GW of renewable energy, saving $1.3 billion over traditional upgrades.[19] This result indicates that Massachusetts may also see cheaper and faster generator interconnection with GETs, which could also support the state's climate goals. Another study using the Kansas and Oklahoma systems and interconnection queues found a similar result: GETs could double the capacity for new generation on existing infrastructure, per a study done by the Brattle Group.[20]

B.4 Are there quantifiable benefits to Massachusetts ratepayers from the implementation of these technologies?

While no study has specifically quantified the value of GETs in Massachusetts, the Idaho National Laboratory looked at a case study of GETs for offshore wind delivery at Brayton Point and found that GETs provided a cost-effective solution, reducing modeled curtailment by more

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[16] Aivaliotis, Sandy. *Dynamic Line Ratings for Optimal and Reliable Power Flow*. https://cms.ferc.gov/sites/default/files/2020-05/20100623162026-Aivaliotis%2C%2520The%2520Valley%2520Group%25206-24-10.pdf.

[17] Tsuchida, Bruce T., Linquan Bai, Jadon M. Grove, ""Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts," The Brattle Group, April 20, 2024 https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf

[18] Ibid.

[19] "GETting Interconnected in PJM." *RMI*, https://rmi.org/insight/analyzing-gets-as-a-tool-for-increasing-interconnection-throughput-from-pjms-queue/.

[20] Tsuchida, T. Bruce, et al. *Unlocking the Queue with Grid-Enhancing Technologies*. Case Study of the Southwest Power Pool, The Brattle Group, 1 Feb. 2021, https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

than 50%.[21] The payback period for the DLR/APFC solutions were less than one year, compared to several years for a traditional upgrade.

Other examples of cost savings from specific implementations include:

i. Pennsylvania: PPL Electric Utilities deployed DLR to avoid over $20 million in annual grid congestion costs.[22]

ii. Australia: APFC technology is expected to deliver net benefits of up to $268 million to electricity customers by allowing an additional 170 MW of power to be transferred into New South Wales.[23]

iii. England: APFC technology is estimated to save $500M+ by avoiding curtailment costs through an effort by National Grid Electricity Transmission to use APFC on five 275 kV and 400 circuits.[24]

iv. United States: Topology optimization studies in PJM, MISO, SPP and ERCOT markets show reduced congestion costs by 25-50% and reduce renewables curtailment by 50%.[25]

B.5 What are the primary barriers and/or implementation concerns that may prevent a wider adoption of such technologies?

The WATT Coalition sees two primary obstacles to the adoption of GETs:

1. Institutional inertia: Utilities and system operators are slow to change their practices and adopt new approaches. GETs often require buy-in from multiple teams and may touch multiple process at a utility and system operator. Full integration of GETs into grid planning and operations can require new lines of collaboration and additional staff training.

2. Incentives: Investor-owned utilities are not rewarded for reducing energy or transmission costs – their business models are based on building new grid infrastructure. This is why they do not have teams working on operational efficiency of the grid. Without financial incentive to pursue GETs, utilities have generally deployed

[21] Gentle, Jake, "Webinar: Assessing the Value of Grid Enhancing Technologies: Modeling, Analysis, and Business Justification," Energy Systems Integration Group, June 1, 2024.
[22] *Dynamic Line Rating Activated by PPL Electric Utilities | PJM Inside Lines*. https://insidelines.pjm.com/dynamic-line-rating-activated-by-ppl-electric-utilities/. Accessed 3 Jul. 2025.
[23] Castro, Roberto. "Transgrid Unlocks 170 MW of Capacity Using SmartValve." *Smart Wires Inc.*, 3 Nov. 2022, https://www.smartwires.com/2022/11/03/transgrid-delivers-45-million-victoria-nsw-interconnector-upgrade-releasing-flow-of-renewable-energy-between-states/.
[24] *Working Smarter to Get to Net Zero | National Grid*. https://www.nationalgrid.com/stories/journey-to-net-zero-stories/working-smarter-get-net-zero. Accessed 3 Jul. 2025.
[25] Tsuchida, Bruce T., Linquan Bai, Jadon M. Grove, ""Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts," The Brattle Group, April 20, 2024 https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf

them as R&D projects to collect data, or one-off implementations that have not been scaled.

These barriers are not insurmountable, and there is growing momentum for GETs in spite of these challenges. In 2021, comments representing 90 stakeholder organizations (including the Massachusetts Attorney General,[26] the Massachusetts Municipal Wholesale Electric Company[27] and National Grid[28]) encouraged FERC to include GETs in transmission planning and/or generator interconnection.[29] Since then, the U.S. had its first fully operational deployment of DLR in Pennsylvania in 2022,[30] and large deployments have followed in the Midwest[31] and New York.[32] However, nearly four years after so many stakeholders pushed FERC to act on GETs, the deployments in the U.S. are still very modest. Meanwhile, utilities in Norway[33] and Finland[34] are deploying DLR system-wide. FERC policy in Order Nos. 881, 2023 and 1920 will eventually require utilities to consider GETs in operations, interconnection and regional planning, but the implementation deadlines have been pushed out and the requirements for transmission technologies may not be enforced. State policy will help push these technologies forward on a faster timeline to serve state goals.

B.6 What changes, if any, does the Company recommend to the current regulatory framework to facilitate the cost-effective deployment of these technologies?

Improved transparency and specific incentives would both accelerate GETs deployments in Massachusetts. Transparency into grid constraints and/or utility timelines and processes for GETs adoption would help vendors understand the opportunities for GETs in Massachusetts, and

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[26] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=A0CA6B13-1EFB-C87E-A4A6-7C797D500000 at 30-33.
[27] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=EFB676CB-3BEE-C830-BD56-7C7A2A200000 at 6.
[28] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=03F7E29F-2EE0-CFD8-9F6E-7C79C8C00000 at 32-33.
[29] WATT Coalition Reply Comments, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, FERC RM21-17-000, November 30, 2021, https://watt-transmission.org/wp-content/uploads/2021/11/Reply-Comments-of-the-WATT-Coalition.pdf
[30] PPL Electric Utilities Wins 95th Annual Edison Award, Edison Electric Institute, June 12, 2023, https://www.eei.org/en/news/news/all/ppl-electric-utilities-wins-95th-annual-edison-award
[31] *See* "Great River Energy Launches Largest Dynamic Line Rating Project in the U.S. with Heimdall Power," Chicago WGN9, March 20, 2024, https://wgntv.com/business/press-releases/ein-presswire/697107716/great-river-energy-launches-largest-dynamic-line-rating-project-in-the-u-s-with-heimdall-power/ *and* "AES and LineVision release results of study assessing largest single deployment of Dynamic Line Ratings in the US," AES Corporation, April 15, 2025, https://www.aes.com/press-release/aes-and-linevision-release-results-study-assessing-largest-single-deployment-dynamic
[32] LineVision Operationalizes Dynamic Line Ratings in New York to Increase Transmission Capacity and Grid Safety for National Grid, LineVision Inc., May 9, 2024, https://www.linevisioninc.com/news/linevision-operationalizes-dynamic-line-ratings-in-new-york-to-increase-transmission-capacity-and-grid-safety-for-national-grid
[33] "Heimdall Power launches world's first system-wide capacity monitoring project with Elvia," Heimdall Power, September 18, 2023, https://heimdallpower.com/system-wide-with-elvia/
[34] "Fingrid deploys Gridraven DLR solution across transmission grid," Smart Energy International, June 4, 2025, https://www.smart-energy.com/industry-sectors/smart-grid/fingrid-deploys-gridraven-dlr-solution-across-transmission-grid/

help stakeholders engage productively in forums from local rate cases to the independent system operator. Incentives would help the utility justify the cost of system upgrades and allocate staff time and resources towards identifying good GETs opportunities. The incentives can be designed to ensure that ratepayers save money, through models like "shared savings" where a utility is compensated based on the cost-savings generated by a solution.[35]

Regulatory jurisdiction is a jagged line when it comes to transmission technologies. Because Massachusetts's transmission rates are set at FERC, the state cannot directly incentivize specific transmission investments in the transmission rates. However, an incentive could be paid from a general fund. Alternatively, the DPU could support utilities in filing for an incentive with FERC. FERC is directed to incentivize transmission technologies under Section 219(b)3 of the Federal Power Act, which it has never implemented.[36] In addition, FERC's regulation of local transmission planning is far more limited than its regulation of regional transmission planning, which could leave authority with states to require specific technologies.

Conclusion

We appreciate the DPU's attention to the opportunities and barriers for GETs. We hope that these comments help describe the potential for GETs deployments in Massachusetts

Sincerely,

Julia Selker

Executive Director

WATT Coalition

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[35] Rob Gramlich and T. Bruce Tsuchida, "Improving Transmission Operation with Advanced Technologies: A Review of Deployment Experience and Analysis of Incentives," June 24, 2019. https://watt-transmission.org/wp-content/uploads/2019/06/brattle-grid-strategies-paper-improvingtransmissionoperationwithadvancedtechnologies.pdf

[36] WATT/AEE filing to FERC in incentives Notice of Proposed Rulemaking, June 2020. https://watt-transmission.org/wp-content/uploads/2020/08/watt-coalition-aee-filing-to-ferc-in-incentives-nopr.pdf

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BY ELECTRONIC DELIVERY ONLY

July 3, 2025

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Re: D.P.U. 25-69
Investigation Into the Use of Advanced Conductors, Grid-Enhancing Technologies and Other Advanced Transmission Technologies to Enhance the Performance of the Commonwealth's Transmission System in Applications that are Subject to Federal Jurisdiction, Pursuant to St. 2024, c. 239, § 121.
Comments submitted by Conservation Law Foundation

Dear Hearing Officer Andrew Strumfels:

I. Introduction

Conservation Law Foundation ("CLF")[1] encourages the Department to support Companies implementing grid-enhancing technologies ("GETs") with pilot programs and demonstration projects to avoid the need for building new power lines or substations and increase the capacity of existing infrastructure. These technologies have the potential to play a pivotal role in helping the Commonwealth achieve its climate and energy affordability goals. CLF appreciates the opportunity to comment on this inquiry as a stakeholder and offers the

[1] Founded in 1966, CLF is a nonprofit, member-supported, regional environmental organization working to protect New England's environment for the benefit of all people. We use the law, science, and markets to create solutions that build healthy communities, sustain a vibrant economy, and preserve natural resources. CLF appreciates the opportunity to submit comments in D.P.U. 25-59.

following responses to the questions posed by the Department to inform the General Court of its report.[2]

II. CLF's Recommendations

CLF offers the following responses to the questions posed by the Department:

What types of advanced technologies have the Companies used or will consider integrating:

CLF encourages the DPU to ensure that electric distribution companies ("EDCs") and other necessary parties deploy and consider integrating a wide array of GETs to optimize the existing grid and meet the Commonwealth's climate change and energy goals. The industry generally groups GETs under three categories: Dynamic Line Ratings ("DLR"), Topology Optimization ("TO"), and Flexible Alternating Current Transmission Systems ("FACTS").

EDCs should deploy GETs wherever feasible, including DLR systems, which have been shown to reduce transmission congestion by optimizing the use of existing infrastructure and "improving the transfer capability of individual lines."[3] Unlike static line ratings ("SLR"), DLR systems adjust in real time to ambient conditions and "can increase transfer capability of lines by 5-25 percent," helping to alleviate congestion costs and reduce the curtailment of renewable energy resources.[4] In addition, FACTS offer significant benefits.[5] Advanced FACTS devices, particularly the latest-generation devices, improve the speed and flexibility of grid response to faults, disturbances, and other events that can destabilize the grid, and can support the integration of variable renewable resources to the grid by helping to regulate voltage and frequency.[6] TO software uses artificial intelligence to find ways to reconfigure the grid and "reroutes power flows around bottlenecks."[7] TO software can help reduce congestion and optimize transmission by automatically rerouting power flows, opening and closing circuit breakers to redirect energy from overloaded lines to underutilized ones.[8]

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[2] DPU 25-69, GET NOI VO Opening (June 2, 2025) (CLF notes the DPU, after coordinating with the Department of Energy Resources ("DOER") and the Massachusetts Clean Energy Center ("MassCEC") will submit a report to the Joint Committee on Telecommunications, Utilities, and Energy no later than September 1, 2025).[2]
[3] Srishti Slaria et al., *Expanding the Possibilities: When and Where Can Grid-Enhancing Technologies, Distributed Energy Resources, and Microgrids Support the Grid of the Future?* RESOURCES FOR THE FUTURE (Sept. 2023), https://media.rff.org/documents/Report_23-13.pdf (hereinafter RFF GETs Report).
[4] *Id*.
[5] *Id*.
[6] *Id*. (citing U.S. Department of Energy 2020).
[7] *Id*.
[8] *Id*. (citing U.S. Department of Energy 2020).

Can these technologies help to avoid or delay the need for building new power lines or substations? Please explain your answer.

GETs can improve efficiency, capacity, and operational flexibility of the existing grid and the transmission system. By maximizing the use of current infrastructure, GETs can reduce or defer the need to build new power lines or substations. As noted by Resources for the Future, GETs "maximize the capacity of existing rights of way, reducing the need for some new transmission projects and deferring the construction of others."[9] This can result in costs savings and faster deployment timelines.

In addition to reducing infrastructure needs, GETs can mitigate siting impacts of new transmission development.[10] For example, installing FACTS devices on nearby lines can reduce stress on the grid during construction and upgrades.[11] One study found that installing FACTS on nearby lines could save up to $70 million in costs of redispatch over a 3.5-year upgrade period, with installation costs amounting to 2 to 6 percent of those savings in avoided congestion costs.[12]

GETs can also improve reliability during system upgrades by minimizing the frequency and duration of outages while new lines are built or upgraded. As new projects come online, GETS can "enhance their value, increasing the benefit–cost ratio of these traditional investments and potentially improving their approval rate."[13] In cases where proposed infrastructure may have negative environmental justice, community, or ecological impacts, planners should be required to prioritize GETs and other lower-impact alternatives.[14]

Generally, do these technologies support Massachusetts climate goals and clean energy objectives? Please explain your answer.

GETs can play a key role in supporting Massachusetts' climate mandates and clean energy objectives, including the Commonwealth's binding target of net-zero greenhouse gas emissions by 2050, as required by the *Global Warming Solutions Act* ("GWSA")[15] and *An Act to Create A Next-Generation Roadmap for Massachusetts Climate Policy* ("Roadmap Law"),[16] as well as the goals set out in the state's Clean Energy and Climate Change Plans for 2025 and 2030 and 2050.[17] Meeting these goals will require a substantial buildout of offshore wind and other

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[9] *Id*.
[10] Reply and Post-Technical Conference Comments of Acadia Center and Conservation Law Foundation, No. RM21-17-000, U.S. Federal Energy Regulatory Commission (Nov. 30, 2021) (citing NARUC Comments at 9; NESCOE Comments at 41).
[11] RFF Report, *supra* note 3.
[12] *Id*.
[13] *Id*. (citing Tsuchida et al. 2023).
[14] *Id*.
[15] St. 2008, c. 298.
[16] St. 2021, c. 8.
[17] *Massachusetts Clean Energy and Climate Plan for 2025 and 2030*, Executive Office of Energy and Environmental Affairs (June 30, 2022), https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-

clean energy generation and storage projects. By reducing the need for new transmission infrastructure, GETs can help advance decarbonization efforts more quickly while also saving costs.[18] Importantly, GETs can be deployed within months, helping relieve congestion in renewable energy projects that are backlogged in interconnection queues and face multi-year delays due to capacity constraints.[19] They can also optimize transmission pathways while new offshore wind infrastructure is being developed and brought online.[20]

Are there quantifiable benefits to Massachusetts ratepayers from the implementation of these technologies?

GETs can provide benefits to Massachusetts ratepayers. GETs help avoid costly investments in new transmission lines and substations by increasing the capacity of existing infrastructure. Additionally, GETs reduce congestion costs and accelerate the integration of clean energy infrastructure into the grid, providing reliability improvements to Massachusetts consumers.

According to the U.S. Department of Energy, transmission capacity within the United States must expand 2.7-4.1 times the 2020 level in order to achieve a clean energy grid by 2050 "under a high electricity demand scenario."[21] However, at the end of 2023, nearly 2,600 GW gigawatts of renewable energy projects remained stalled in interconnection queues nationwide "due to high network upgrade costs and insufficient transmission capacity," bottlenecks that "resulted in over $11.5 billion in congestion charges for U.S. consumers in 2023."[22] GETs can help overcome these barriers and benefit Massachusetts ratepayers by increasing capacity of existing infrastructure, directly benefiting Massachusetts ratepayers.

GETs can also benefit Massachusetts ratepayers by providing efficient and cost-effective solutions compared to traditional transmission upgrades.[23] For example, "replacing end-of-life phase-shifting transformers with [advanced power flow control] APFC devices can provide a

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2030/download; *Clean Energy and Climate Plan for 2050*, Executive Office of Energy and Environmental Affairs (Dec. 2022).

[18] *Transmission Rules to Boost Clean Energy Transition, Cut Costs, and Enhance Climate Resilience*, ENVIRONMENTAL LAW & POLICY CENTER (May 13, 2024), https://elpc.org/news/transmission-rules-to-boost-clean-energy-transition-cut-costs-and-enhance-climate-resilience/.

[19] Mike O'Boyle et al., *Supporting Advanced Conductor Deployment: Barriers and Policy Solutions*, ENERGY INNOVATION: POLICY & TECHNOLOGY LLC AND GRIDLAB (April 9, 2024), https://www.2035report.com/wp-content/uploads/2024/04/Supporting-Advanced-Conductor-Deployment-Barriers-and-Policy-Solutions.pdf.

[20] Jay Caspary, T. Bruce Tsuchida, *Unlocking the Queue with Grid Enhancing Technologies: Case Study-Southwest Power Pool Study Approach*, THE BATTLE GROUP, GRID STRATEGIES LLC (Jan. 27, 2021), https://www.brattle.com/wp-content/uploads/2021/06/21200_unlocking_the_queue_with_grid_enhancing_technologies.pdf.

[21] Assessment and Evaluation of Grid Enhancing Technologies (GETs) Prepared for American Council on Renewable Energy (ACORE), Electric Power Engineers (Feb. 24, 2025), https://acore.org/wp-content/uploads/2025/02/Assesment-and-Evaluation-of-Grid-Enhancing-Technologies-GETs-Report.pdf.

[22] *Id*.

[23] *Id*.

more cost-effective and efficient alternative."[24] Because GETs can be deployed within one to two years, they enable faster connection of renewable energy resources, reducing costs for consumers and providing potential financial incentives to utilities.[25]

What are the primary barriers and/or implementation concerns that may prevent a wider adoption of such technologies?

There are barriers and concerns to implementation that may prevent a wider adoption of such technologies, but there are ways to overcome such barriers. Key challenges include but are not limited to regulatory challenges within the planning process, gaps in awareness and technical expertise regarding GETs, and questions on how to allocate costs and benefits.

To overcome these obstacles, a standardized approach by the Department regarding the planning, control, and operation of GETs is essential. Standardization will ease integration and reduce the burden on individual utilities.[26] The Department should also promote greater awareness of GETs and require that utilities educate their customers about these technologies and their benefits such as reducing costs and meeting the Commonwealth's climate change goals.

III. Conclusion/CLF Additional Recommendations

CLF encourages the Department to take proactive steps to encourage wider adoption of GETs within the Commonwealth.

Pilot Projects/Demonstration Projects

The DPU can encourage pilot programs and demonstration projects to build utility and stakeholder confidence in GETs. For example, the Smart Wires' National Grid project in the United Kingdom at three substations unlocked 1.5 gigawatts of additional transmission capacity without building new infrastructure.[27] Similarly, the New York State Energy Research and Development Authority is allocating $12 million to fund GET demonstration projects focused on

[24] *Id*.
[25] *Id*.
[26] *Id*.
[27] *National Grid: Northern England Projects*, SMART WIRES, https://www.smartwires.com/2024/04/02/national-grid-northern-england-projects/ (last accessed on June 30, 2025).

improving transmission capacity in New York.[28] ISO-New England forums have also showcased case studies exploring TO algorithms to improve grid operation and reduce congestion.[29]

Performance-Based Incentives and Reporting

The Department should also require utilities to evaluate GETs as part of their transmission planning processes. To further incentivize adoption, the Department should establish performance-based incentives rewarding utilities that successfully deploy GETs and achieve measurable benefits.[30] The DPU should also mandate regular reporting by utilities on GETs deployment to identify opportunities for support and improvement.

Stakeholder Engagement and Education

Effective stakeholder engagement and education on GETs is crucial to advancing deployment of GETs.[31] Utilities should promote greater awareness among customers and community groups about the capabilities and advantages of these technologies. Increased understanding will help gain support and facilitate the Commonwealth's progress toward its climate and clean energy goals.

CLF appreciates the Commonwealth's efforts to engage the public in its work and looks forward to working with the DPU as it helps move our Commonwealth toward a cleaner and electrified future. Thank you for your time and attention to this matter. Please do not hesitate to reach out with any questions.

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[28] *$12 Million is Now Available to Support Innovative Electric Grid Technologies*, NYSERDA (April 16, 2025), https://www.nyserda.ny.gov/About/Newsroom/2025-Announcements/2025-04-16-Governor-Hochul-Announces-12-Million-Is-Now-Available-To-Support-Grid-Tech#:~:text=The%20Grid%20Enhancing%20Technologies%20(GETs,electricity%20to%20homes%20and%20businesses (NY seeks "eligible proposers for product development projects, demonstration projects or research studies that will help to enable a high-performing electric grid and have the potential to transform the delivery of clean, renewable energy resources.").

[29] New Grid: *Transmission Topology Optimization: A Software Grid-Enhancing Technology*, ISO-NE Forum on Grid-Enhancing Technologies, Westborough, MA (June 18, 2025), https://www.iso-ne.com/static-assets/documents/100024/2025_06_18_gets_newgrid_materials.pdf.

[30] *Increasing Transmission and Grid-Enhancing Technologies (GETs)*, NATIONAL CAUCUS OF ENVIRONMENTAL LEGISLATORS (Feb. 26, 2024), https://ncelenviro.org/articles/increasing-transmission-and-grid-enhancing-technologies-gets/ ("This year, at least nine states are considering legislation that encourages or incentivizes the introduction of GETs into transmission systems. This includes California, Connecticut, Maryland, Massachusetts, Minnesota, New York, South Carolina, Utah, and Virginia); *see also* Montana Senate Bill 301: *Generally revise utility lines and facilities laws* (May 12, 2025); https://bills.legmt.gov/#/laws/bill/2/LC0322.

[31] *DPU Docket No. 21-50 Notice of Inquiry by the D.P.U. on its own Motion into Procedures for Enhancing Public Awareness of and Participation in its Proceedings*, CLF Comments on Draft Policy (Jan. 20, 2023), https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//hdfghebj?4zhmsaRDsxIe6+0f2aYgRWFJ0ioKRMXdZYr4j7j/42qk9v9pxUxyG6LkaCeWBSjqbmMlNqhcSkxPf0qUr1gASPKrYE1qejvebf677PtCVStUdHoHpEGELGLGjR+ZpYgt.

Respectfully Submitted,

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Outlook

[Draft] Fw: [EXTERNAL] Follow-up to MassCEC Stakeholder Session

From Andrew.W.Strumfels@mass.gov

From: Tsuchida, Bruce <Bruce.Tsuchida@brattle.com>
Sent: Monday, June 23, 2025 4:26 PM
To: Sarah Cullinan <scullinan@masscec.com>
Subject: [EXTERNAL] Follow-up to MassCEC Stakeholder Session

CAUTION: This email originated from outside of the organization. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Hi Sarah,

It was a pleasure to meet you at the MassCEC Stakeholder Session today.
Below are a few public reports I can share with you.
They are listed in reverse-chronological order (from newest to oldest).
The first (latest) may cover all three questions we discussed today.

April 2025:
Whitepaper titled "Incorporating GETs and HPCs into Transmission Planning Under FERC Order 1920."
https://www.brattle.com/wp-content/uploads/2025/04/Incorporating-GETs-and-HPCs-into-Transmission-Planning-Under-FERC-Order-1920.pdf
This whitepaper highlights both the pitfalls and opportunities of Grid-Enhancing Technologies (GETs) and High-Performance Conductors (HPCs) under FERC Order 1920.
Using 25 real-world case studies it demonstrates how GETs and HPCs can fulfill the *Seven Benefits* discussed in Order 1920, and discusses how state regulators can take advantage of the Order to help integrate GETs and HPCs into transmission planning, which is not just an opportunity but a necessity for achieving cost-effective, sustainable grid development over the next several decades.

April 2023:
This whitepaper titled "Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts."
https://www.brattle.com/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf
This whitepaper looks at different timeframes of how GETs can help with transmission buildouts and was filed as part of the client's comments for the draft DOE Transmission Study.

February 2021:
Unlocking the Queue Study
https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf
The study analyzed how three types of GETs (Dynamic Line Rating, Topology Optimization, and Advanced Power Flow Control) can help interconnect more renewables using SPP as a testbed.

At the time of the study, SPP had more than 9,000 MW of renewable projects with Interconnection Agreements that did not move forward because of the perceived curtailment (that would lead to undesirable commercial outcomes for the renewable developers).
The study showed that GETs could double the amount of renewables that the SPP grid can interconnect, with a one-time expense of $90 million, or a payback period of half a year.
When scaled, the nationwide annual benefits would exceed $5 billion and offset carbon emission from more than all new cars sold in a year.
FERC has cited this study a number of times, including the recent two FERC NOPRs (Generation Interconnection, and Long-term Transmission Planning and Cost Allocation) and their final rules (Order 2023 and 1920).

June 2019:
Whitepaper titled "Improving Transmission Operation with Advanced Technologies: A Review of Deployment Experience and Analysis of Incentives."
https://www.brattle.com/wp-content/uploads/2021/05/16634_improving_transmission_operating_with_advanced_technologies.pdf
This whitepaper lists various examples of how GETs can help the grid, and provides a discussion on the misaligned incentives that are hindering the widespread adoption of GETs, along with a "benefitssharing" incentive proposal.
The whitepaper was filed by the client at the Federal Energy Regulatory Commission (FERC) in response to FERC's "Inquiry Regarding the Commission's Transmission Electric Incentives Policy (PL193000)."
The whitepaper was later cited in the House Select Committee report on climate crisis.
Most recently, the "benefits sharing" mechanism discussed in the whitepaper was introduced as a new legislation to the House and Senate in March this year (See: Advancing Grid Enhancing Technologies Act.)

Bruce

T. Bruce Tsuchida
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ASI
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June 4, 2025

Re: Responses to DPU 25-69

To the Massachusetts Department of Public Utilities,

Below, please find ASI's responses to the Department's Request for Comments under DPU 25-69, addressing questions for grid-enhancing technology companies. We appreciate the opportunity to contribute to this effort and are committed to supporting Massachusetts' clean energy, resilience, and grid modernization goals.

If you have questions regarding this submission, please do not hesitate to reach out directly.

Sincerely,

Tate Krasner
Chief of Staff
ASI
704-654-0419
tate@airspace-intelligence.com

1. **Please describe any advanced transmission or distribution technologies your company offers.**
   ASI is a Massachusetts-based AI company that builds platforms to predict, simulate, and optimize critical industries. It builds a 4D predictive simulation and decision-support platform that enables utilities and grid operators to optimize grid planning and operations in order to increase reliability, reduce costs, and enhance sustainability.
   a. **What is the current technology readiness level of your product(s)?**
      ASI's platform is currently at TRL 9 in other critical infrastructure sectors, including aviation, defense, and logistics. It actively manages over 25% of all U.S. air traffic and supports live defense operations. We are currently prototyping with utilities to adapt and deploy the technology for grid planning and clean energy integration.
   b. **Is/are the product(s) commercially available?**
      Yes. Our platform is commercially available and in operational use in aviation and logistics. We are now actively partnering with utilities to bring the same decision-support and optimization capabilities to energy planning and grid operations.

2. **Please describe the primary cost categories and amounts associated with your product(s).**
   ASI leverages a software-as-a-service (SaaS) model that provides access, data integration, workflow configuration, and support under a fixed licensing model.
   a. **What are the typical installation costs for your technology (per mile, per site, per kilowatt/megawatt, or as applicable)?**
      As a software platform, costs are determined by the scope, complexity, and data associated with deployments.
   b. **What are the expected operations and maintenance costs over the technology's useful life?**
      Under the software-as-a-service (SaaS) model, operations and maintenance costs are fully covered under the license.
   c. **What factors most strongly affect the cost effectiveness of your technology?**
      Cost effectiveness is primarily driven by data availability and quality, complexity of grid scenarios, and avoided capital costs by optimizing the grid via software vice hardware.

3. **Please describe the primary benefits associated with your product(s).**
   ASI's platform helps utilities and developers make faster, data-driven planning and operational decisions by simulating millions of grid scenarios and identifying high-impact strategies for resilience, clean energy integration, and cost-effective infrastructure deployment. It enables outcomes such as more accurate outage forecasts, optimized energy storage siting, and faster interconnection assessments–leading to measurable reductions in factors such as restoration time, emissions, and project delays.
   a. **What are the technical, operational, and commercial benefits of your technology?**
      Technical: Creates a dynamic, forward-looking, continuously updating 4D digital twin of the grid over time and space using data fusion and AI modeling.
      Operational: Improves accuracy of outage forecasting, interconnection feasibility, and system planning.
      Commercial: Reduces interconnection study churn, avoids overbuilding, accelerates clean energy deployment timelines, and positions Massachusetts as a grid-ready state that's attractive to developers.

b. **Does your technology support broader public policy goals including, but not limited to, the integration of clean energy, emissions reductions, grid resilience, or cost savings for customers and ratepayers?**
   Yes. ASI's platform directly supports Massachusetts' clean energy, resilience, and affordability goals by enabling faster integration of renewables and energy storage; reducing emissions through better outage preparedness and less reliance on backup generation; improving resilience with scenario-based planning; and lower costs for customers by avoiding inefficient upgrades and stabilizing electricity prices.

4. **Does your technology integrate with existing grid infrastructure and utility operation systems?**
   Yes. ASI's platform is designed as a modular software overlay that integrates with existing utility datasets, planning tools, and operational workflows–without requiring changes to physical infrastructure.
   a. **Are there unique requirements required to operationalize your technology (e.g., siting and permitting, workforce training, operability with utility systems, etc.)?**
      There are no unique requirements required to operationalize our technology. The primary needs are access to relevant data (e.g., topology, load, interconnection queues, etc.) and collaboration with planning and engineering teams.
   b. **What is the typical deployment timeline for your solution from planning to operation?**
      ASI prioritizes rapid deployment, typically launching an initial operational version of the platform within weeks. From there, we scale functionality and model complexity iteratively based on utility feedback and project goals, enabling fast value delivery while aligning with internal planning processes.
   c. **Do you offer support or training for utilities to assist with the deployment and operation of your technology?**
      Yes. Support, training, and onboarding are all included under ASI's license to ensure alignment with workflows across grid planning and operations.

5. **Where have your technologies been deployed to date?**
   ASI's platform is fully deployed and operational in aviation and defense–including United Airlines, Alaska Airlines, and the United States Air Force–managing real-time operations for over 25% of U.S. air traffic and supporting live defense operations. Within the energy sector, ASI is currently prototyping new capabilities with National Grid and Eversource in Massachusetts to support energy storage planning and outage forecasting, respectively.
   a. **Are there specific examples where your solution was deemed to be more cost effective than a traditional grid upgrade?**
      ASI is currently exploring early-stage initiatives with utilities such as National Grid and Eversource to validate that our platform can discover cost-effective alternatives–such as optimized energy storage siting and dispatch or proactive resilience planning–to traditional upgrades.
   b. **Are there specific types of projects or system conditions where your technology is particularly valuable?**
      ASI's technology is especially valuable in systems with congested interconnection queues, demand-capacity imbalances, frequent outages, or complex distributed energy resource integration challenges. It excels in complex scenario-planning requiring

multi-variable analysis and optimization across physical, economic, topology, climate, and policy constraints.

c. **Was the deployment subsidized by any government entities or others? If so, how important was this support to deployment?**
ASI has submitted proposals to the MassCEC InnovateMass program in partnership with National Grid and Eversource, and we are actively exploring additional funding opportunities through the Commonwealth. Public support is critical to help de-risk early-stage validation and accelerate deployment in the energy sector, where procurement and planning cycles are long and complex.

6. **What, if any, adoption barriers has your company encountered?**
A key barrier is the slow procurement and planning cycle for emerging technologies in the utility sector, especially for software solutions. Further, the current lack of active federal pilot funding increases reliance on state-level programs to support early-stage demonstration, limiting opportunities for rapid validation.

a. **Are there specific barriers that currently limit the use of your technology in Massachusetts relative to other jurisdictions?**
Yes. While Massachusetts is a national policy leader on energy initiatives, it lacks state funding mechanisms on par with states like New York and California, where software innovation is more strongly supported and well funded. Even with well-developed, clearly scoped projects and engaged utility partners, it remains difficult to identify and secure funding for early-stage demonstration. Further, the funding that is available is often narrowly focused on hiring incentives or tax credits, rather than directly supporting grid modernization and planning innovation. Additionally, Massachusetts' innovation programs are more oriented toward deep tech and hardware, which can overlook software-based solutions that deliver faster, lower-cost outcomes and reduce reliance on physical infrastructure upgrades.

b. **Please describe your experience in working with utilities or government entities in Massachusetts and/or other jurisdictions.**
ASI is actively engaging with National Grid, Eversource, and other utilities to pursue projects related to outage forecasting, energy storage planning, and additional grid use cases. In parallel, ASI is in discussions with MassCEC, the Executive Office of Economic Development, and the Department of Public Utilities to align our technology with the Commonwealth's resilience, decarbonization, electricity cost, and economic development goals.

c. **Do you have any recommendations or considerations on how to facilitate cost-effective and timely adoption of advanced grid technologies?**
Massachusetts can accelerate adoption by creating dedicated, streamlined funding pathways for grid planning and software innovation, not just loan programs, venture capital, hiring initiatives, or tax credits. We recommend establishing flexible pilot programs that allow rapid deployment and iterative validation, while also providing longer-term funding for ramp-up pathways. Additionally, the Commonwealth could support cross-agency coordination and funding efforts to streamline projects, enable access to data, and reduce friction in early-stage utility partnerships. Finally, we encourage evaluating total system value–including avoided infrastructure costs and speed to deployment–when assessing new technologies.

June 30, 2025

Massachusetts Department of Public Utilities
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Boston, MA 02110

Submitted via email to dpu.efiling@mass.gov and andrew.w.strumfels@mass.gov.

Re: Docket number D.P.U. 25-69
The response of Noteworthy AI to the D.P.U.'s Request for Comment included in their June 2, 2025 Order Opening Investigation: *D.P.U. 25-69: The Commonwealth of Massachusetts Department of Public Utilities – Investigation Into the Use of Advanced Conductors, Grid-Enhancing Technologies and Other Advanced Transmission Technologies to Enhance the Performance of the Commonwealth's Transmission System in Applications that are Subject to Federal Jurisdiction, Pursuant to St. 2024, c. 239, § 121.*

To Grid-Enhancing Technology Companies:

1. Please describe any advanced transmission or distribution technologies your company offers.

   Founded in 2020, Noteworthy AI offers cutting-edge distribution-grid technology designed to significantly enhance utilities' asset visibility, situational awareness, and reliability of overhead distribution circuits through automated, fleet-based inspections. Their flagship product—Noteworthy Inspect—combines two advanced components:

   - Inspect Edge: Rugged machine-vision cameras and edge-compute mounted on standard utility fleet vehicles. It automatically captures high-resolution images, accurately geolocates poles and pole-top hardware, and generates LiDAR-comparable 3D point clouds. The real-time, on-vehicle AI detects anomalies such as pole damage, leaning poles, vegetation encroachment, lighting issues, and unauthorized attachments.

   - Inspect Cloud: A secure analytics platform that aggregates data from Inspect Edge, applies proprietary machine learning models, and provides a map-centric interface. Users can filter and search for specific asset conditions, review images, and integrate findings via APIs into GIS and asset-management systems.

   This automated edge-to-cloud pipeline enables utilities to shift from manual, labor-intensive inspections, assessments and audits of their overhead distribution system to continuous, condition-based monitoring—delivering significant O&M cost reductions and faster and improved identification of asset issues, asset inventory, post-storm damage assessments, lighting audits, 3rd Party attachment audits and make-ready surveys, and vegetation condition assessments.

   a. What is the current technology readiness level of your product(s)?

   Noteworthy AI's Inspect Platform is at Technology Readiness Level 9 (TRL 9).

   b. Is/are the product(s) commercially available?

Noteworthy AI's Inspect Platform is a commercially mature, mission-proven solution ready for at-scale deployment. Noteworthy AI has achieved this through successful, ongoing field installations with utilities such as Florida Power & Light, Exelon, Southern Company, FirstEnergy, and United Illuminating, thereby validating its performance, reliability, and seamless integration into utility workflows and asset management systems.

2. Please describe the primary cost categories and amounts associated with your product(s).

   a. What are the typical installation costs for your technology (per mile, per site, per kilowatt/megawatt, or as applicable)?

   The two main cost components of the technology include the Inspect Edge camera system and the analytics. The camera system can be rented or purchased. The analytics are priced on a per-pole basis. The installation costs of the camera system, on a per-vehicle basis, are negligible and can usually be completed in a few hours.

   b. What are the expected operations and maintenance costs over the technology's useful life?

   The system requires little ongoing maintenance, aside from periodically wiping the camera's lenses to ensure clarity. Its usable life is 3 years.

   c. What factors most strongly affect the cost effectiveness of your technology?

   The cost-effectiveness of Noteworthy AI's Inspect platform stems from several key factors: it converts routine utility fleet operations into high-frequency, autonomous inspections—eliminating the need for dedicated crews or vehicles; it delivers up to 75% reductions in operations & maintenance costs by enabling continuous, condition-based monitoring (versus time-based inspections); early detection of defects like leaning poles, vegetation encroachment, and component damage prevents costly unplanned outages and repairs, improving reliability; and it delivers multi-use data—supporting storm damage assessment, vegetation management, broadband planning, and joint-use auditing—which amplifies value per inspection effort. These combined efficiencies yield strong financial ROI and heightened grid resilience.

3. Please describe the primary benefits associated with your product(s).

   a. What are the technical, operational, and commercial benefits of your technology?

   Noteworthy AI's Inspect platform delivers a suite of technical, operational, and commercial benefits:

   - Technical: It uses rugged, machine-vision cameras combined with edge-based AI on routine fleet vehicles to generate high-resolution, geolocated imagery and LiDAR-like 3D point clouds. Proprietary machine-learning models running both at the edge and in the cloud detect defects such as pole leaning, hardware damage, vegetation encroachment, lighting issues, idle transformers, and unauthorized attachments. The Inspect Cloud platform enables search, asset tagging, and seamless GIS integration, facilitating rapid, data-driven assessment.

- Operational: By converting normal fleet operations into automated inspection workflows, the system minimizes the need for dedicated patrols and crews. It enables continuous, condition-based monitoring—substantially reducing inspection cycle time and improving situational awareness. Pilots demonstrate up to 75% reduction in O&M costs, enhanced crew safety, and prioritized field response through proactive defect identification.

- Commercial: The technology is fully commercial and field-proven (TRL 9), with deployments completed or ongoing at utilities such as Florida Power & Light, Exelon, Southern Company, FirstEnergy, and United Illuminating. Installations have shown strong ROI through capital deferrals, better risk mitigation, and streamlined operations. The system's multi-use data supports diverse business functions, including storm response, vegetation management, lighting audits, and broadband surveys, maximizing value through a single data collection effort.

In summary, Noteworthy AI provides a robust, scalable, and ROI-driven inspection solution that delivers immediate operational improvements and long-term commercial value.

b. Does your technology support broader public policy goals including, but not limited to, the integration of clean energy, emissions reductions, grid resilience, or cost savings for customers and ratepayers?

Yes —Noteworthy AI's technology supports broader public policy goals as follows:

- Grid resilience: The platform provides continuous situational awareness and early identification of infrastructure issues (e.g., pole defects, vegetation encroachment), which improves storm preparedness and accelerates recovery—enhancing overall system resilience.

- Cost savings for customers & ratepayers: Automated inspections can reduce O&M costs by up to 75%, reduce outage-related costs, and enable targeted capital investments, leading to more stable rates and better customer value.

- Equity & community benefits: Deployments—such as our $1.8M Connecticut PURA IES project—prioritize underserved communities, supporting infrastructure equity and economic development in vulnerable areas.

In sum, Noteworthy AI's Inspect technology delivers tangible contributions to reliability, affordability, and equity—advancing key public utility policy objectives.

4. Does your technology integrate with existing grid infrastructure and utility operation systems?

Noteworthy AI's Inspect platform is designed for seamless integration with existing utility infrastructure and operational systems. The Inspect Cloud component features an extensible API that integrates directly with utilities' GIS, asset management, and work-order scheduling systems—Noteworthy AI is an ESRI partner, with built-in ArcGIS support. The system also supports flexible deployment architectures, including deployment in customers' cloud tenants, ensuring compatibility with utilities' existing IT/OT environments. In practice, this enables utility engineers to access geolocated images and AI-identified defects directly within their familiar platforms, allowing for seamless integration into routine operations and workflows.

a. Are there unique requirements required to operationalize your technology (e.g., siting and permitting, workforce training, operability with utility systems, etc.)?

Inspect requires only minimal hardware installation, quick workforce onboarding, and standard IT integration—enabling utilities to operationalize the technology rapidly and cost-effectively with no permitting or additional infrastructure requirements. Inspect Edge units mount directly onto existing fleet vehicles—no specialized vehicles or system operators are required. Noteworthy AI ensures secure, encrypted data management, granting utilities full ownership and control over collected imagery and asset data—aligned with critical infrastructure security standards. Lastly, since the platform uses existing fleets for deployment, no new site permits, rights-of-way, or FAA clearances are required, significantly lowering deployment barriers compared to stationary sensors or LiDAR setups.

b. What is the typical deployment timeline for your solution from planning to operation?

Utilities can expect full solution activation—from planning to continuous operation—to take approximately 1 month, depending on scale and extent of fleet operations. Larger deployments (i.e. more camera installations) could take significantly longer, as the installations would require additional coordination with utility fleet management teams.

c. Do you offer support or training for utilities to assist with the deployment and operation of your technology?

Yes. Noteworthy typically handles deployment (installation). As the camera systems operate fully autonomously once deployed, no direct or manual operation is required. Our team provides training and support on our cloud application, including guidance on understanding and integrating analytics results.

5. Where have your technologies been deployed to date?

In December 2024, Noteworthy AI was awarded a $1.8M project through the Connecticut Public Utilities Regulatory Authority's (PURA) Innovative Energy Solutions (IES) Program. This is a 15-month project commencing in Q1 2025, in which Noteworthy AI partners with United Illuminating to pilot and further develop three use cases utilizing Noteworthy AI's fleet vehicle-mounted smart cameras and AI. These use cases are focused on automating pole load and clearance field assessments, enhancing vegetation management performance, and identifying specific defects in overhead distribution infrastructure.

Noteworthy has also deployed its technology for various use cases across multiple pilot and expansion projects with large investor-owned utilities and cooperatives, including FirstEnergy, Florida Power & Light, Alabama Power, Georgia Power, and Xcel Energy. With FirstEnergy, for example, Noteworthy has deployed its platform across three separate demonstration programs. The demonstrations identified and geolocated poles, detected crossarm damage such as split wood or other deterioration, and conducted an audit of streetlights. Additionally, in 2024, working with a major IOU in the Southeastern US, Noteworthy demonstrated the value of real-time damage assessments immediately following the landfall of two major hurricanes, an engagement that is expected to significantly expand for the 2025 storm season.

a. Are there specific examples where your solution was deemed to be more cost effective than a traditional grid upgrade?

Not applicable. Noteworthy AI's technology is not an alternative to a traditional grid upgrade, but rather a valuable tool for operating the existing overhead distribution system in a more effective and cost-efficient manner, enabling data-driven decision making through increased situational awareness.

b. Are there specific types of projects or system conditions where your technology is particularly valuable?

Noteworthy AI's Inspect platform is especially valuable in distribution overhead circuit environments characterized by:

- Aging infrastructure — Areas with wood poles, deteriorating hardware, or structural degradation benefit greatly from automated inspections that identify defects early, preventing failures and extending asset life.
- Storm-prone areas — Frequent severe weather zones see improved resilience and post-storm response, as automatic, drive-by data collection enables quick condition awareness before and after events.
- Dense pole attachment activity — Regions with extensive third-party attachments or joint-use arrangements gain from Inspect's precision in identifying and measuring such attachments, speeding service requests, and ensuring NESC compliance.
- High vegetation encroachment — Feeders passing through tree-heavy corridors or prone to overgrowth see outsized benefits, as Inspect can detect risky vegetation encroachment and reduce outage risks through proactive trimming.

In summary, Noteworthy AI's technology is particularly well-suited for projects involving legacy asset management, vegetation risk reduction, attachment oversight, storm resilience, and multi-use infrastructure assessments—all use cases where it delivers automation, accuracy, and cost-effective scale.

c. Was the deployment subsidized by any government entities or others? If so, how important was this support to deployment?

Yes, for one of our deployments. In December 2024, Noteworthy AI was awarded approximately $1.8 million through the Connecticut PURA IES Program to partner with UI on a grid inspection project.

This subsidy was crucial to advancing the deployment:

- It provided dedicated funding for the deployment of edge cameras on UI fleet vehicles, enabling automated inspections of ~34,000 poles (roughly 20% of UI's system) over a 15-month period.
- This public support covered the majority of project costs, significantly reducing the financial burden on Noteworthy AI, and accelerated its implementation timeline and development of use cases specifically tailored to meet UI's challenges and opportunities.
- Importantly, the subsidy helped de-risk early-stage adoption of the technology, allowing operational validation in real-world utility environments—an essential step toward securing additional partnerships and future commercial rollouts.

6. What, if any, adoption barriers has your company encountered?

a. Are there specific barriers that currently limit the use of your technology in Massachusetts relative to other jurisdictions?

The barriers are only limited by the Massachusetts electric utilities priorities to advance and automate to more efficient and effective overhead distribution system inspection, surveys and audits, as well as competing initial funding sources necessary to pilot and bring Noteworthy AI's technology to scale, which will unlock significant future savings and improvements to the quality of service.

b. Please describe your experience in working with utilities or government entities in Massachusetts and/or other jurisdictions.

To date, other than several preliminary discussions with Massachusetts-based utilities, Noteworthy AI has not directly deployed its technology in the state. Separately, we have worked with MassCEC through its internship program to source engineering interns in prior years.

c. Do you have any recommendations or considerations on how to facilitate cost-effective and timely adoption of advanced grid technologies?

To facilitate cost-effective, timely adoption of advanced grid technologies such as Noteworthy AI's Inspect platform, I recommend the following:

Conduct brief, focused pilot programs to validate readiness and quantify value, including clearly defined mechanisms embedded in regulatory planning for pilots, as well as bringing the technology to scale. These mechanisms should include predetermined cost-recovery pathways, such as inclusion in DPU-approved Electric Sector Modernization Plans (ESMPs) and associated tariffs, to ensure utilities can confidently plan and fund expansion.

In the absence of these structured pathways, utilities often lack the necessary budgets to move beyond pilot stages, resulting in a loss of momentum and unrealized benefits. Establishing explicit regulatory requirements for business-case justification and project funding approval would incentivize utilities to adopt proven technologies at scale, ensuring Massachusetts ratepayers swiftly reap the benefits of grid resilience, clean energy integration, and cost savings.

Sincerely,

Christopher Ricciuti
Founder & CEO
Noteworttthy AI Inc