# COST AND BENEFITS ASSESSMENT OF GRID-ENHANCING TECHNOLOGIES IN MAINE

*Prepared for the Maine Public Utilities Commission*

August 2025

Energy+Environmental Economics

Energy and Environmental Economics (E3) is an analytically driven consulting firm focused on the transition to clean energy resources with offices in San Francisco, Boston, New York, Calgary, and Denver. Founded in 1989, E3 delivers analysis that is widely utilized by governments, utilities, regulators, and developers across North America. E3 completes roughly 350 projects per year, all exclusively related to the clean energy transition, across our three practice areas: Climate Pathways and Electrification, Integrated System Planning, and Asset Valuation, Transmission, and Markets. The diversity of our clients – in their questions, perspectives, and concerns – has provided us with the breadth of experience needed to understand all facets of the energy industry. We have leveraged this experience and garnered a reputation for rigorous, unbiased technical analysis and strong, actionable strategic advice.

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# Acronym Definitions

| Acronym | Definition |
|---|---|
| **DoE** | Department of Energy |
| **DLR** | Dynamic Line Ratings |
| **GETs** | Grid Enhancing Technologies |
| **GRIP** | Grid Resilience and Innovation Partnerships |
| **ISO-NE** | ISO New England |
| **MPUC** | Maine Public Utilities Commission |
| **NMISA** | Northern Maine Independent System Administrator |
| **PFC** | Power Flow Controls |
| **RPS** | Renewable Portfolio Standard |
| **T&D** | Transmission and Distribution |
| **TO** | Topology Optimization |
| **VPP** | Virtual Power Plants |

# Executive Summary

Maine's electric grid is entering a period of transformation. To meet its climate goals, the state has enacted a suite of policies aimed at decarbonizing its energy system. These policies include a Renewable Portfolio Standard (RPS) that mandates 80% renewable electricity by 2030 and 100% by 2050, alongside initiatives to electrify fossil fuel–dependent energy sectors such as heating and transportation. Together, these policies are set to fundamentally reshape how energy is produced and consumed across the state, driving increased demand for electricity while shifting where and how it is generated. This transformation will place new demands on Maine's transmission and distribution (T&D) infrastructure, which must adapt to deliver power from new generation sources to emerging centers of consumption.

After decades of flat or declining load growth, electricity demand in Maine is now expected to rise due to widespread electrification, increased reliance on electric end uses, and the growing adoption of electric vehicles. This rising demand may place a strain on the state's aging T&D infrastructure, which was not designed for the evolving dynamics of a renewables-heavy grid. At the same time, climate change is amplifying the risk of extreme weather events such as ice storms and high winds, which threaten system reliability. These compounding pressures highlight the urgent need for resilient, flexible, and cost-effective solutions to modernize Maine's grid.

Conventional grid investments alone may yield suboptimal results in the effort to reform the grid to meet these challenges. Transmission projects are capital-intensive and often face long lead times for planning, permitting, and construction. Due to the timeline and cost associated with these investments, novel technological tools may be able to provide immediate relief to stressed grid infrastructure in a cost-effective manner. Grid Enhancing Technologies (GETs) represent a set of such tools and have been identified for review by the Maine legislature under Public Law 2023, Chapter 553 ("An Act to Ensure That the Maine Electric Grid Provides Additional Benefits to Maine Ratepayers"). In this legislation, GETs are defined in Maine statute as technologies – excluding generation assets or energy storage – that enhance or increase the efficiency of existing T&D assets.

**This report outlines the opportunities and considerations for deploying Grid Enhancing Technologies in Maine**, as evaluated by E3 in collaboration with the Maine Public Utilities Commission (MPUC) under the directive of Public Law 2023, Chapter 553. The report focuses on commercially available, cost-effective GETs that are well-suited to Maine's grid conditions that could defer or reduce the need for traditional infrastructure investments, ultimately lowering ratepayer costs, easing grid constraints, and supporting the state's decarbonization goals. Specifically, it evaluates Dynamic Line Ratings (DLRs), which use sensors and associated data integration software to provide real-time transmission line capacity ratings based on environmental conditions; Power Flow Controls (PFC), which use modular power electronics to redirect power flows; and Topology Optimization (TO), which leverages software to dynamically reconfigure grid topology in real time. In addition to traditionally defined GETs, this document also considers the application of Virtual Power Plants (VPPs), which aggregate distributed resources that can provide grid services, mitigate peak demand, and increase resilience for isolated communities.

Maine's unique grid characteristics, including its long radial lines, limited redundancy in rural areas, and seasonal demand fluctuations, present both opportunities and challenges for some of these GETs. For instance, DLR technologies can be especially valuable during winter peaks by leveraging low ambient temperatures to increase transmission line capacity, albeit with a potential reduction in transmission line capacity during summer months. PFC can reduce congestion on key corridors by shifting power flows away from constrained paths. TO can help improve grid resilience by identifying alternate configurations when faults or line outages occur. However, both benefits may be limited if there are few alternative power flow routes along existing corridors that connect rural renewable sites to major load centers. VPPs can reduce the need for costly upgrades in distribution-constrained areas by lowering net demand during critical periods.

The broader policy and market landscape in Maine is generally favorable for GET adoption. Recent federal programs – such as the Grid Resilience and Innovation Partnerships (GRIP) program, authorized under the Infrastructure Investment and Jobs Act – have provided funding and technical assistance for states to deploy innovative grid solutions. National laboratories, the US Department of Energy (DoE) and other jurisdictions are continuing to evaluate proper use cases for GETs by tracking validated performance data, deployment best practices, and regulatory frameworks. Other countries and states, including the United Kingdom, New York, and Pennsylvania, have begun incorporating GETs into formal T&D planning processes. By performing targeted evaluations of how specific GETs might affect aging or constrained lines, Maine has an opportunity to join this cohort in leveraging GETs to help achieve its decarbonization targets and reduce ratepayer costs as part of an integrated system planning process.

E3's evaluation of GETs for the MPUC involved an extensive literature compilation and review of existing GETs application and studies. In addition, E3 conducted an illustrative case study for the deployment of DLRs to increase the penetration of wind resources along a congested transmission line. This study revealed that DLRs return a benefit-cost ratio of over 12:1, indicating that resources invested into targeted DLRs may deliver significantly higher returns to ratepayers through curtailment reduction than comparable investments in traditional transmission upgrades. To move from illustrative concept to implementation, further detailed analysis and stakeholder engagement would be required.

**Key Takeaways:**

1. **Maine Faces a Confluence of Grid Pressures**: Aging infrastructure, rising electrification-driven demand, integration of variable renewables, and climate-related reliability risks all point to the need for significant investment in T&D infrastructure. Maine's geographic and climatic characteristics exacerbate these challenges.
2. **GETs Can Be Part of the Solution**: Technologies such as DLR, PFC, TO, and VPPs offer viable, cost-effective alternatives to traditional grid upgrades in certain use cases. They can

increase utilization of existing assets, reduce congestion, and provide operational flexibility while deferring or avoiding more expensive capital projects.

3. **Maine's Grid Characteristics Are Well-Suited for Select GETs**: The state's radial transmission lines, forecasted winter peaking conditions, and constrained interconnection points suggest particularly strong alignment with DLR, which can help modulate transmission line capacity to increase deliverability during high winter demand periods. Conversely, the cost-effectiveness of PFC and TO may be limited by the radial nature of the transmission network, which are better suited for alleviating congestion on networks with greater redundancy. VPPs offer additional benefits by enhancing resilience and managing distributed load and generation, and can help reduce peak demand if deployed at sufficient scale.

4. **Early Deployment Opportunities Exist**: E3 identified near-term use cases where GETs could provide immediate value. These can serve as pilots to demonstrate effectiveness, build institutional knowledge, and refine deployment strategies.

5. **The Broader Investment Landscape is Evolving**: Federal funding allocated prior to 2025, growing industry experience, and a supportive policy environment are reducing barriers to GET deployment. Maine is well-positioned to take advantage of this momentum and incorporate GETs into its broader grid modernization strategy.

# Section 1. Introduction and Legislative Context

On March 19, 2024, Gov. Janet Mills signed Public Law 2023, Chapter 553 ("An Act to Ensure That the Maine Electric Grid Provides Additional Benefits to Maine Ratepayers") into law, which amended Title 35-A of the Maine Revised Statutes to require the Public Utilities Commission to periodically review the applicability of grid-enhancing technologies ("GETs") on the Maine T&D systems.[1] The Act defines grid-enhancing technology or GETs as "any hardware or software technology that enables enhanced or more efficient flow of electricity across the existing electric transmission and distribution system," excluding generation assets and energy storage. Specifically, the goal of the periodic review is to determine whether GETs "could be implemented by a large investor-owned transmission and distribution utility to reduce or defer the need for investment in grid infrastructure" in Maine.[2] In keeping with the legislative mandate, the Maine Public Utility Commission ("MPUC" or "the Commission") may produce a report describing the GETs identified in the review, and may file information from the report for use in rate cases or other proceedings involving large investor-owned utilities (IOUs), including the integrated grid planning proceeding required pursuant to 35-A MRS section 3147(2). MPUC has commissioned Energy and Environmental Economics, Inc. ("E3") to conduct the 2025 review.

The key value proposition of GETs is that they may improve the utilization of existing T&D systems, reducing the need to build out new lines or replace existing lines. In some cases, these technologies may be more cost-effective than investments in new or upgraded conventional infrastructure. The State of Maine has multiple electric grid objectives that GETs could potentially facilitate:

- **Customer Affordability:** Maine's average retail electricity cost across all sectors in January 2025 was $0.2170/kWh, the fifth-highest rate in the continental U.S.[3] Deferring transmission upgrades through lower-cost improvements to existing infrastructure has the potential to reduce costs to Maine ratepayers.
- **Renewable Integration:** GETs can enable transmission networks to accommodate variability in power flows stemming from solar and wind production. This flexibility can help reduce curtailment of renewable generators and facilitate the integration of additional renewable energy resources. The additional flexibility provided by GETs could be an additional tool for grid operators to support Maine's achievement of its legislative target of generating 80% of its electricity from renewable sources by 2030 and 100% by 2050.[4]

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[1] *Maine Legislature, SP0257, Item 3, 131st Legislature,* *https://legislature.maine.gov/legis/bills/getPDF.asp?paper=SP0257&item=3&snum=131*

[2] ***Maine Legislature**, SP0257, Item 3, 131st Legislature,* *https://legislature.maine.gov/legis/bills/getPDF.asp?paper=SP0257&item=3&snum=131*

[3] ***U.S. Energy Information Administration**, Electric Power Monthly: Table 5.6.A.,* *https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a*

[4] ***DSIRE**, Maine – Net Metering,* *https://programs.dsireusa.org/system/program/detail/452*

- **End-Use Electrification:** Maine utilities forecast future load increases driven by electric vehicle adoption and electrification of building heating needs.[5] More efficient use of existing transmission assets might help serve these growing loads without requiring (or deferring) new transmission or distribution system upgrades, new generation buildout, or increased dispatch of high-cost and emission-intensive thermal plants.

As part of this analysis E3 evaluated the following three GETs, selected in consultation with the MPUC due to their relatively short deployment timelines and low upfront costs. Further details on these GETs can be found in Table 1.

- **Dynamic Line Ratings ("DLRs")**: Use of sensors to dynamically adjust line and transformer ratings in near-real time in response to environmental conditions. DLRs can be used to increase line ratings and reduce congestion, especially during winter months.
- **Advanced Power Flow Controls ("APFCs")**: Installation of hardware to change the reactance in a transmission or distribution line to alter the power flow direction and increase line capacity. This can redirect power from congested lines to alternate circuits, reducing congestion costs.
- **Topology Optimization ("TO")**: Software models that automatically reconfigure power flow routes around congested areas. This can more efficiently utilize spare grid capacity to bypass congestion.

E3 also evaluated the following non-GETs technology, selected in consultation with the MPUC due to its potential to deliver benefits similar to those of traditional GETs:

- **Virtual Power Plants ("VPPs")**: Aggregation of distributed energy or behind-the-meter resources, including demand response programs. VPPs can flexibly dispatch power or reduce peak demand in critically congested areas of the grid to mitigate curtailment and reduce system costs.

[5] ***Versant Power**, Integrated Grid Planning Forecasting Approach,* https://www.versantpower.com/docs/default-source/environmental/111424-integrated-grid-planning-forecasting-approach-compressed.pdf?sfvrsn=cb51c6b_1

***Table 1:*** *Summary of Technologies Evaluated* [6]

| Technology | Initial Deployment Timeline | Subsequent Deployment Timeline | Hardware or Software? | Transmission or Distribution Deployment? |
|---|---|---|---|---|
| **Dynamic Line Rating** | 1-3 Years | <3-6 Months | Both | Both |
| **Advanced Power Flow Controls** | 1-3 Years | <3-6 Months | Hardware | Transmission |
| **Topology Optimization** | 1-3 Years | <3-6 Months | Software | Both |
| **Virtual Power Plants** | 1-3 Years | Varies | Software | Distribution |

While GETs can provide many grid benefits, their cost-effectiveness depends on several contextual factors. These factors include, but are not limited to:

- **Volume of curtailment**: Optimizing power flow on the grid provides a greater benefit when the existing grid is operating inefficiently, or where low-cost generation resources are not able to dispatch due to transmission constraints. Conversely, the benefits of GETs are more limited when overall curtailment levels are lower.
- **Electric grid topology**: Because GETs can optimize power flow across multiple transmission lines, their effectiveness depends in part on the layout – or topology – of the network. More interconnected systems will have a greater variety of power flow routes to optimize, while those with fewer linkages may find the benefits of GETs limited by hardware constraints or specific transmission constraints in the system.
- **Ease of implementation and logistical feasibility:** Some GETs require a combination of hardware installation and software implementation across transmission assets of various ages and conditions, along with coordination across multiple planning entities at both the T&D levels. This complexity can lead to programmatic bottlenecks that limit the effectiveness of the technological solutions themselves. Some of these bottlenecks are discussed further in Section 2.

This report is laid out as follows:

[6] **U.S. Department of Energy**, *Liftoff: Innovative Grid Deployment*, https://liftoff.energy.gov/wp-content/uploads/2024/04/Liftoff_Innovative-Grid-Deployment_Final_4.15.pdf

- **Section 2** discusses the benefits and drawbacks of GETs technologies and VPPs and summarizes several case studies on the effectiveness of deployment programs that have introduced these technologies in other regions.
- **Section 3** discusses the regulatory environment, topology of the Maine grid in further detail, including both the ISO-NE and Northern Maine Independent System Administrator (NMISA) balancing authorities, and key drivers of transmission investment needs.
- **Section 4** discusses the recommended use cases for each of the technologies reviewed in Maine.
- **Section 5** summarizes the findings of the report and suggests next steps and actions the PUC may undertake to further assess GETs deployment in Maine.

# Section 2. Value Proposition of Grid-Enhancing Technologies

## What are GETs?

Grid Enhancing Technologies (GETs) refer to both hardware and software technologies designed to enhance the capabilities of existing T&D infrastructure.[7] Traditional transmission upgrades can be costly and time-intensive, not only due to the cost and complexity of constructing the upgrades themselves but also due to the siting and permitting challenges associated with large-scale infrastructure development. Due to their small size, modularity, and compatibility with existing grid infrastructure, GETs have the potential to be implemented on a shorter timeline and may also be more cost-effective than conventional solutions under certain conditions. For example, rebuilding or reconductoring lines can often take five to ten years and can require service interruptions, while many GETs can be deployed in under one year for a fraction of the cost without service interruptions. GETs are a subcategory of advanced transmission technologies, which include a broad range of both mature and emerging transmission technologies of various scales, including high-voltage direct current (HVDC) lines, advanced line designs, advanced conductors, transmission-paired energy storage, and advanced flexible transformers.[8]

Beyond their cost advantages relative to conventional transmission upgrades, GETs can play a role in supporting grid performance and reliability. A major benefit that GETs can provide is congestion alleviation across the grid. Grid congestion occurs when there is insufficient capacity to support the most efficient flow of electricity across the system.[9] These inefficiencies can increase real-time energy prices for consumers and can lead lower-cost generators to reduce or curtail output that would otherwise be dispatched to serve load. Congestion often impacts renewable generators, since the timing of these generators' output is weather-dependent and may not align with times of highest demand. Curtailment of renewables increases the cost of compliance with state policies, including Maine's RPS of 80% by 2030, by requiring additional renewable capacity to be developed to replace the lost production from curtailed resources. Further, curtailment also increases energy market costs for ratepayers, as higher-priced generation resources with available transmission deliverability must be dispatched to serve load in place of curtailed generation.

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[7] **U.S. Department of Energy**, *Grid Enhancing Technologies: A Case Study on Ratepayer Impact*, https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf

[8] **U.S. Department of Energy**, *Advanced Transmission Technologies Report*, https://www.energy.gov/sites/prod/files/2021/02/f82/Advanced%20Transmission%20Technologies%20Report%20-%20final%20as%20of%2012.3%20-%20FOR%20PUBLIC.pdf

[9] **U.S. Department of Energy**, *National Transmission Needs Study*, https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf

GETs may also be effective at mitigating future grid uncertainties on a cost-effective basis. For example, the timing and magnitude of beneficial electrification-driven peak load growth is uncertain. In some circumstances, GETs can be deployed faster and cheaper than traditional solutions, permitting grid operators to respond to unexpected increases in load growth up to a certain magnitude (although large load increases would likely necessitate a more robust transmission upgrade planning process). Since transmission investment costs are typically passed on to ratepayers, GETs may reduce near-term customer costs by enabling transmission owners to delay some planned investments.

Despite these advantages, the benefits of GETs are contingent on their ability to integrate with and complement existing grid infrastructure. As such, determining whether GETs are the optimal solution to a particular system management challenge requires an understanding of the underlying grid topology and condition. For example, a successful GETs deployment requires a foundation of IT integration into utility system operations. This is because GETs function by sending signals to the grid to transmit information about different types of system conditions, such as weather or congestion. For grid system operators to be able to interpret and act upon those signals requires a combination of communications technologies, system digitization and data management systems.[10] This IT infrastructure is a pre-requisite to unlocking the benefits of GETs.

GETs may also be limited by the existing grid equipment and topology. GETs enhance existing T&D networks but cannot overcome fundamental system limitations. For example, PFC and TO rely on multiple alternative paths for power to flow from a generator to a load, and so their use may be limited for a radial grid with few, if any, alternative paths or built-in redundancies.

Overall, while GETs can deliver benefits under specific circumstances, they should always be evaluated relative to conventional transmission solutions to ensure that investments are right-sized to meet current and near-future grid needs while minimizing costs to ratepayers. That means that there will be cases where GETs will be the preferred option, and other cases where conventional technologies will be better suited to meet system needs. Ultimately, these innovative technologies are a useful additional tool for grid planners that should be evaluated fairly and consistently in T&D planning efforts and deployed when determined to be the most cost-effective solution.

# Technologies

The technologies considered in this report are summarized in Table 2 and described in further detail below:

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[10] **U.S. Department of Energy**, *Liftoff: Innovative Grid Deployment*, https://liftoff.energy.gov/wp-content/uploads/2024/04/Liftoff_Innovative-Grid-Deployment_Final_4.15.pdf

***Table 2:*** *Summary of Technologies Evaluated*

| Technology | Initial Deployment Timeline | Subsequent Deployment Timeline | Hardware or Software? | Transmission or Distribution Deployment? |
|---|---|---|---|---|
| **Dynamic Line Rating** | 1-3 Years | <3-6 Months | Both | Both |
| **Advanced Power Flow Controls** | 1-3 Years | <3-6 Months | Hardware | Transmission |
| **Topology Optimization** | 1-3 Years | <3-6 Months | Software | Both |
| **Virtual Power Plants** | 1-3 Years | Varies | Software | Distribution |

### *Dynamic Line Ratings:*

Dynamic Line Ratings (DLRs) involve using real-time environmental and weather data to adjust line and transformer ratings based on conditions such as the temperature of a transmission line, which allows for more efficient management of the line's health and performance.[11] While several different types of DLR technology are commercially available, the key mechanisms in any DLR system are (a) the installation of sensing or monitoring hardware on or near targeted transmission lines to measure the line's temperature, sag, or tension; and (b) a software interface that can process any collected data into actionable insights into the line's condition. [12]

The key value proposition of DLRs is to integrate temperature considerations into a transmission line's operating limits. High temperatures negatively impact both the performance and long-term health of transmission lines, increase transmission losses, and can cause lines to physically sag on their poles. Sagging of lines increases the risk of conductors contacting their surroundings, which may cause damage to the lines themselves, outages, or wildfires. Similarly, overheated transformers can experience accelerated deterioration or catastrophic failure. Transmitting electricity heats transmission lines and associated equipment, as does direct sunlight and absorbing ambient heat from the air. Conversely, cooler ambient temperatures, wind, and shade can cool transmission equipment, allowing it to transmit greater amounts of electricity safely.

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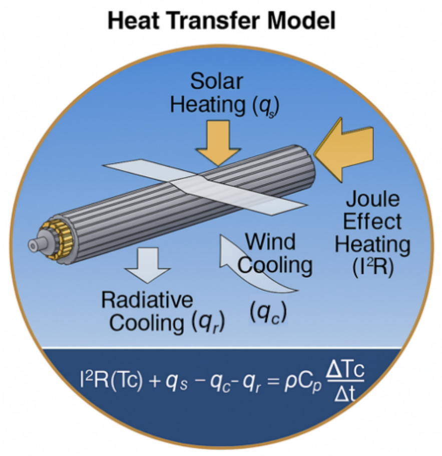
[11] ***U.S. Department of Energy,*** *Grid Enhancing Technologies: A Case Study on Ratepayer Impact,* *https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf*

[12] ***U.S. Department of Energy,*** *Dynamic Line Rating, June 2019, https://www.energy.gov/oe/articles/dynamic-line-rating-report-congress-june-2019#:~:text=Traditional%20solutions%20to%20alleviating%20congestion,allow%20for%20greater%20transmission%20usage.*

***Figure 1:*** *Environmental Effects on Transmission Line Temperature*[13]




Transmission elements have fixed power transfer ratings, often calculated using worst-case environmental assumptions, limiting the amount of electricity that can be transmitted to ensure that flows on the line remain at or below safe limits. By deploying real-time sensors onto key locations and incorporating advanced weather models, DLRs allow grid operators to dynamically adjust these limits based on the actual conditions. Grid operators can increase ratings on cold, cloudy, windy days to more efficiently transmit electricity, and decrease ratings on hot, sunny, windless days to protect the equipment from being overloaded. By enabling these operations, DLR deployments may be able to extend the lifespan of grid equipment, reduce resource curtailment, and increase grid efficiency more cheaply and quickly than traditional transmission upgrades.

### *Advanced Power Flow Controls:*

Power Flow Controls (PFCs) and Advanced Power Flow Controls (APFCs) are power-electronics-based hardware technologies that can be installed at multiple points along existing transmission lines (although typically installed at or near substations) to actively manage and direct electricity flow in real time.[14] They achieve this by injecting a voltage to increase or decrease the reactance in the connected line, enabling operators to redistribute power more efficiently across the network. This capability helps alleviate grid congestion by optimizing alternative routes and grid configurations. APFCs can also quickly react to unexpected line outages, increasing the overall reliability of the system. APFCs are more compact, faster, and efficient than older PFCs, but perform essentially the same function.

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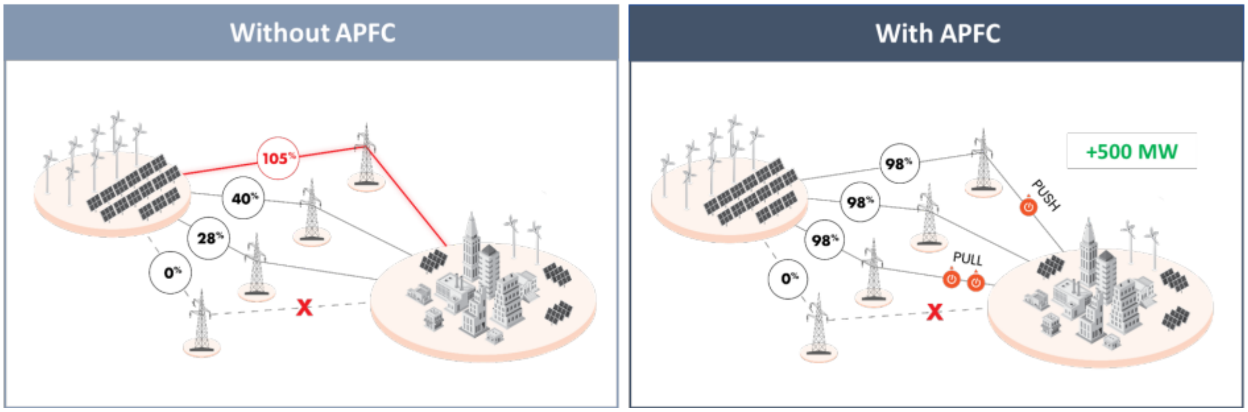
[13] ***U.S. Department of Energy***, *Grid Enhancing Technologies: A Case Study on Ratepayer Impact,* *https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf*

[14] ***The Brattle Group***, *Congestion Mitigation with Grid-Enhancing Technologies,* *https://www.brattle.com/wp-content/uploads/2022/10/Congestion-Mitigation-with-Grid-Enhancing-Technologies.pdf*

***Figure 2:** Illustration of Advanced Power Flow Controls*[15]



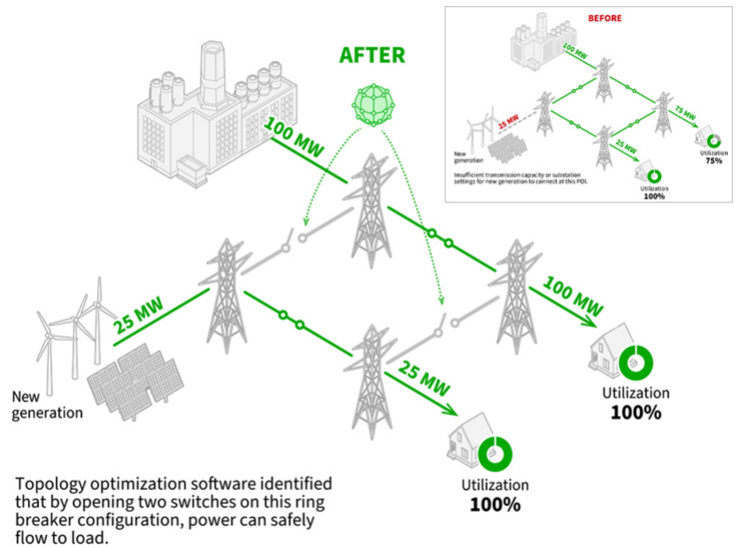

While PFCs and APFCs are modular and can be installed along most operating transmission lines, they are most applicable in highly interconnected meshed networks with multiple different routes across different transmission lines to route power. They are less effective on transmission networks with few alternative paths for power to flow.

### *Topology Optimization:*

While APFCs use hardware upgrades along individual lines to redirect power flow throughout the grid, Topology Optimization (TOs) employs software models to achieve a similar effect, identifying and deploying optimal reconfigurations to flexibly and efficiently route the flow of electricity around congested elements. TOs can be complemented by the ability of PFCs to modulate the power flow patterns across particular lines, when installed together, and are also best deployed in meshed networks.

[15] *Ibid*

***Figure 3:*** *Topology Optimization Software Actions*[16]




Live topology optimization and control can also allow for rapid reconfigurations to alleviate congestion during extreme weather events. One use case is showcased by SPP's 2018 study that analyzed the opportunities of increasing power flow through lines to heat them and reduce icing which can cause line failure during severe winter conditions. [17]

Given the integrated need to install power flow controls on the hardware side to maximize the benefits of topology optimization on the software side, implementation can be challenging, as grid operators need to understand how to utilize both the PFCs and the TO software in tandem to promote optimal power flow across the network.

### *Virtual Power Plants:*

Virtual Power Plants (VPPs) are software platforms that aggregate distributed energy resources to mimic dispatchable resources.[18] This allows these resources, which individually may be too small to engage in market activities, to have significant impacts on grid operations. While not considered a GET by either general convention or the Maine Legislature, VPPs can deliver benefits analogous to those of GETs and can be analyzed alongside them as a non-wires alternative to traditional transmission upgrades.

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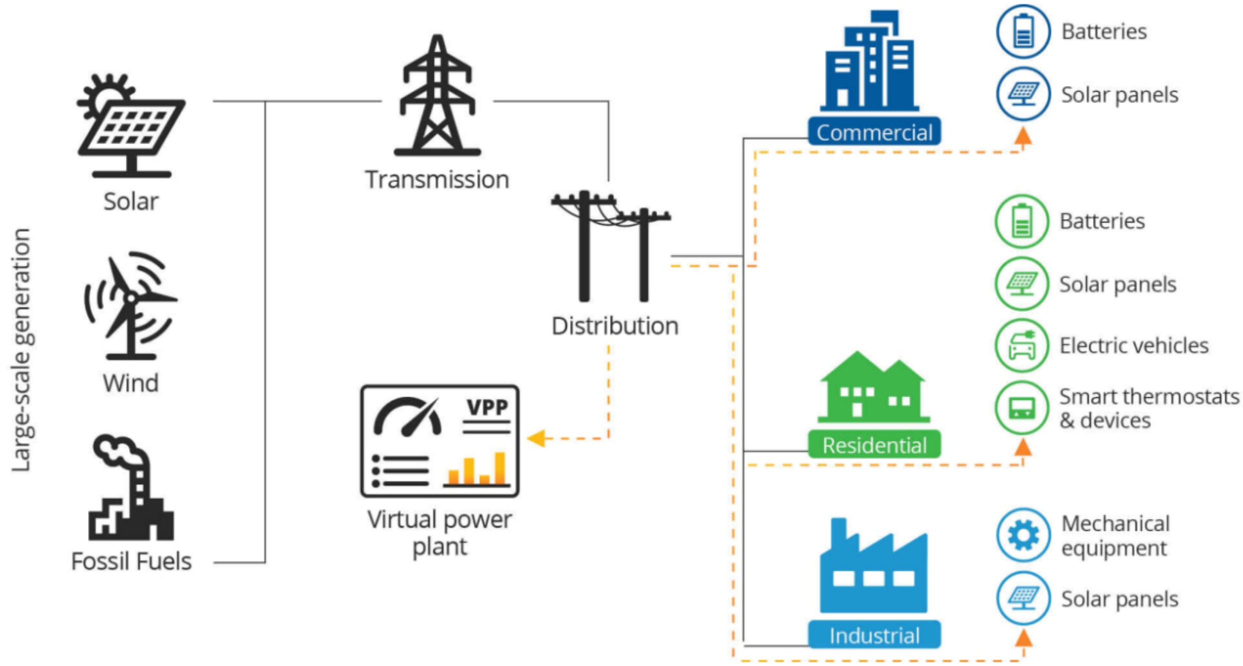
[16] ***RTO Insider***, *RMI Report: Grid-Enhancing Tech Can Speed Renewable Development,* *https://www.rtoinsider.com/71544-rmi-report-grid-enhancing-tech-speed-renewable-development/*

[17] ***Ruiz, P. et al.***, *Transmission Topology Optimization: Pilot Study to Support Congestion Management and Ice Buildup Mitigation, SPP Technology Expo, Nov 2018.*

[18] ***Rocky Mountain Institute***, *Clean Energy 101: Virtual Power Plants, https://rmi.org/clean-energy-101-virtual-power-plants/*

*Figure 4: Virtual Power Plant Operations*[19]




VPPs can be used to reduce grid stress by reducing load or discharging power in certain parts of the grid by using resources such as rooftop solar with batteries, EVs and chargers, and commercial and industrial loads. Most deployed VPPs are concentrated in states that have favorable market structures or regulatory mechanisms such as California, Texas, and New York, reflecting the importance of supportive policy, regulatory, and market design frameworks.

The main costs associated with GETs include hardware and installation expenses for real-time monitoring systems, power flow controllers (PFCs), and communication technologies required to enable dynamic decision-making. Additionally, ongoing software and labor costs for operations and maintenance (O&M) are necessary to ensure their continued functionality and effectiveness.

## Implementation Considerations

Each of the technologies reviewed in this report play an important role in expanding system operators' ability to meet grid needs. Still, it is important to contextualize the specific use cases where each tool is most helpful. Each technology requires a foundation of technological, grid configuration and/or regulatory structures to be most beneficial for ratepayers. Below, Table 3 summarizes the key points for policymakers and regulators to consider for successful GETs deployment.

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[19] *Dakota Electric Association, Virtual Power Plant Explained,* https://www.dakotaelectric.com/2024/02/01/virtual-power-plant-explained/

*Table 3: GETs Implementation Considerations for Maine*

| GETs | Enabling Conditions | Value Limitations | Key Takeaways for Maine |
| --- | --- | --- | --- |
| **DLR** | • Environmental factors that cool down lines<br>• Communications architecture to interpret information from DLR sensors<br>• Advanced data management systems to display and store signal data | • DLR is less effective on transmission lines that do not have the environmental factors necessary to increase line rating | • DLR is a strong candidate for deployment in Maine on specific transmission lines with the environmental factors most likely to yield an increase in line ratings<br>• Investing in the foundational IT infrastructure is critical for the grid to be able to interpret and react to the signals from DLR sensors |
| **PFC** | • Power line configurations with many redundant lines, such as mesh networks, where power can be redirected to alternate routes | • Grid networks with long radial lines are limited in their ability to redirect power to alternate routes | • The radial nature of Maine's network limits the value of APFCs<br>• Maine could examine if APFCs would be beneficial in the Southern part of the state, where the network has more redundancies |
| **TO** | • Requires the same underlying grid configuration as APFCs<br>• Grid operator needs software able to interact with the hardware of APFC | • Same as APFC | • The radial nature of Maine's network limits the value of TO<br>• Maine could examine if TO would be beneficial in the Southern part of the state, where the network has more redundancies |
| **VPP*** | • Availability of distributed energy resources that can be dispatched<br>• Underlying software and real-time monitoring capabilities to enable activation of resources | • Markets that limit the aggregation and participation of distributed energy resources | • VPPs are a strong candidate to optimize the distribution system in Maine<br>• Realizing the value of VPPs will require a regulatory change to how the market values those resources and utility investments in the software necessary to manage them |
| ***Note:** *VPPs are not traditionally considered GETs* | | | |

# GETs Case Studies

Although the deployment of Grid-Enhancing Technologies (GETs) remains in early stages in the United States, several case studies have demonstrated promising outcomes – highlighting cost savings through congestion mitigation and deferred investments in T&D infrastructure. The State of Maine has the opportunity to demonstrate leadership in evaluating and implementing these novel technologies where doing so is cost-effective and logistically feasible. Below we highlight several successful deployments of GETs.

## DLR Case Studies

### PPL and Ampacimon in Pennsylvania

DLR vendor Ampacimon installed a DLR system on three 230 kV lines (Harwood to Susquehanna lines #1 & #2 and Juniata to Cumberland line) in PPL's service territory in Pennsylvania. The upgrades enabled a 20% capacity gain above static ratings 90% of the time. The DLR was selected in place of a traditional upgrade because of the lower cost and installation speed (< 1 year with no outages for DLR, compared to an estimated timeline of 2-3 years with outages for reconductoring). The $1 million investment cost represented 4.3% of the $23.5 million in congestion costs avoided in a single year and 2% of the approximately $50 million needed for the rebuild of the line.[20]

### LineVision in Upstate New York

To help alleviate grid congestion and facilitate the integration of more renewable energy flowing downstate, New York deployed DLRs on two double-circuit 115 kV lines. DLR vendor LineVision was selected to install these systems, along with a circuit rebuild of five miles. This project was projected to increase the line's capacity by 190 MW, reduce curtailment by 350 MW, and avoid the need to rebuild 26 miles of transmission lines. The estimated cost of the project was $3.2 million less than rebuilding just one mile of a 115 kV line in the area, contributing to both economic and operational benefits. [21] In a FERC filing, National Grid USA, who operates the lines, reported that the DLR deployment led to increases in capacity on two of the four lines. On the other two lines, data from the DLR sensors resulted in a decrease in line rating between 1% and 10%, driven by safety and reliability needs.[22]

### LineVision in United Kingdom

In 2022, LineVision deployed its DLR platform for National Grid U.K. on a 275 kV transmission line linking Penwortham and Kirkby in Cumbria, northern England. This line had previously faced congestion and curtailment challenges due to excess offshore wind power. The DLR solution is expected to increase the line's capacity by an average of over 45%, enabling it to deliver an additional 500 MW of renewable energy. According to National Grid U.K., this will result in approximately £1.4 million (about $1.75 million) in savings on network operating expenses.

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[20] **PPL Electric Utilities**, *Dynamic Line Ratings Operations Integration*, https://www2.pjm.com/-/media/committeesgroups/task-forces/dlrtf/2022/20221212/20221216-item-04---ppl-dlr-presentation.ashx

[21] **WATT Coalition**, *Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts*, https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf

[22] **National Grid**, *Initial Comments of National Grid PLC: Implementation of Dynamic Line Ratings, FERC Docket No. RM24-6-000* https://elibrary.ferc.gov/eLibrary/docketsheet?docket_number=rm24-6-000

### New York ISO Dynamic Line Ratings Simulation

In 2022, the DoE simulated the deployment of a series of GETs on 16 transmission line segments (224 miles) in and around Steuben County, New York.[23] The intent of the study and associated report was to establish a techno-economic framework for the benefits quantification of GETs on the wholesale power market. The GETs deployed included DLRs and PFC.

The study assessed that, on average across all lines and across a year, operating lines with DLRs allows for 3% higher capacity ratings and results in 9% less renewable power curtailment. PFC, depending on the type and scope of equipment deployed, reduced curtailment by 23-43%. All solutions took fewer than 4 years to accrue enough benefits to pay back their initial investment, with DLRs requiring about 1 year.

## Topology Optimization and Power Flow Control Case Studies

### NewGrid's Topology Control in the Midcontinent Independent System Operator ("MISO")

In 2022, Topology Control Software vendor NewGrid identified a reconfiguration to help alleviate the congestion on the Lime Creek to Barton 161 kV line in MISO's operation territory. This reconfiguration led to the line reaching its maximum rated capacity for 108 hours, instead of 220 hours without the reconfiguration. This suggests a 50% reduction in hours that the line is at maximum rated capacity, potentially leading to less equipment degradation and lower congestion costs.[24]

### NewGrid's Topology Control in the Southwest Power Pool ("SPP")

In 2022, NewGrid also identified constraints and proposed reconfiguration solutions on the Osage to Webb Tap 138 kV line and the Cimarron 345/138 kV transformer in SPP's territory. SPP had already identified the constraint on these components as "overlapping Reliability and Economic need" in its 2020 Integrated Transmission Planning ("ITP") Assessment Report.[25] NewGrid's proposed reconfiguration enabled a 10% to 20% increase in power throughput on the Osage to Webb Tap 138 kV line. The proposed reconfiguration solution to reduce summertime peak severe overloads at the Cimarron 345/138 kV transformer reliably enables a 13-23% increase in throughput under congested conditions.[26]

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[23] **U.S. Department of Energy**, *Grid Enhancing Technologies: A Case Study on Ratepayer Impact*, https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf

[24] **WATT Coalition**, *Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts*, https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf

[25] **Southwest Power Pool**, *2020 Integrated Transmission Planning Assessment Report*, https://www.spp.org/documents/63434/2020%20integrated%20transmission%20plan%20report%20v1.0.pdf

[26] **Ruiz, P. A. et al.**, *Congestion and Overload Mitigation Using Optimal Transmission Reconfigurations – Experience in MISO and SPP*, https://www.ferc.gov/media/congestion-and-overload-mitigation-using-optimal-transmissionreconfigurations-experience

## Virtual Power Plant Case Studies

### Green Mountain Power Virtual Power Plant

In 2015, Green Mountain Power (GMP) pioneered residential battery storage and virtual power plant (VPP) initiatives. The program has continued to scale and has approximately 2,900 GMP customers participating in the program as of mid-2023, collectively housing over 4,800 residential batteries. This equates to roughly 36 MW of aggregated battery capacity, representing around 5% of GMP's peak load.

One of the key system-wide economic advantages of GMP's residential battery VPP has been substantial savings achieved through peak power cost avoidance. According to a case study by the DoE, GMP has managed to reduce upwards of 36 MW from its peak load, translating into annual system cost reductions of up to $3 million – benefits enjoyed by all customers across the service area.[27]

GMP estimates the net present value (NPV) of the net benefits of each home battery system at about $2,700 over its lifetime. This figure accounts for customer payments, reductions in forward capacity market and regional network service obligations, energy cost savings, and renewable energy standard benefits. Moreover, GMP's innovative use of VPP technology provides long-term capital savings by deferring or altogether eliminating the need for conventional grid investments, especially those related to T&D infrastructure upgrades.[28]

The program has also notably enhanced grid resilience and improved outage management capabilities. Customers with installed batteries benefit from backup power when grid outages occur, particularly benefiting remote and isolated Vermont communities frequently affected by severe weather events. This benefit is commonly cited as a priority to customers who enroll in the program. Aggregated deployments of batteries in a neighborhood can also have community wide-benefits by creating "resiliency zones" behaving as neighborhood microgrids.[29]

Environmentally, GMP's battery program facilitates reduced reliance on carbon-intensive peak power generation, enhancing renewable energy integration and supporting Vermont's ambitious decarbonization goals. The success of GMP's program offers an insightful case study for the potential application of residential battery storage and VPP systems in the Northern New England region.

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[27] **Green Mountain Power**, *GMP's Request to Expand Customer Access to Cost-Effective Home Energy Storage Is Approved*, https://greenmountainpower.com/news/gmps-request-to-expand-customer-access-to-cost-effective-home-energy-storage-is-approved/

[28] **Green Mountain Power**, *Final Order Approving Tariff Revisions*, https://s3.documentcloud.org/documents/23930878/135809408571174onbase-unity_4129703845439947985406349.pdf

[29] **Green Mountain Power**, *GMP Resiliency Zones*, https://greenmountainpower.com/news/gmp-resiliency-zones/

# Section 3. Overview of Transmission Planning in Maine

Transmission needs in Maine are shaped by a unique combination of geographic, regulatory, and policy factors. In turn, these factors inform how investment in the electric grid should be prioritized to meet current and future needs. As the largest state in the New England region with significant renewable energy potential – particularly in wind, hydro, and biomass resources – Maine faces both opportunities and challenges in ensuring its transmission system can deliver reliable and affordable power. The age and condition of existing infrastructure, combined with expected future load growth, place additional pressure on investment decisions to meet a range of critical needs. This section provides a foundational overview of how transmission planning is conducted in Maine, outlining the institutional roles of state and regional entities, the planning processes they follow, and how these efforts align with broader regional goals through coordination with ISO-NE and neighboring jurisdictions.

## Regulatory Frameworks for Transmission and Distribution Planning

T&D planning in the U.S. operates under a dual regulatory framework. The Federal Energy Regulatory Commission (FERC) governs interstate transmission planning and cost allocation, while state utility commissions oversee distribution systems and local reliability. In Maine, this means bulk transmission is planned through ISO-NE under FERC jurisdiction, while local transmission and distribution planning is overseen by the Maine Public Utilities Commission (MPUC) in coordination with regulated utilities and ISO-NE.

These regulatory frameworks serve as the backdrop for understanding how GETs could be added to the T&D systems in Maine. Additional detail on the key players, their regulatory mandates and roles in T&D planning, evaluation, and approvals, and their relevance to GETs adoption in Maine is included below.

### *Federal: Federal Energy Regulatory Commission*

Starting at the federal level is the Federal Energy Regulatory Commission (FERC).[30] FERC's jurisdiction includes oversight over interstate electrical transmission, wholesale energy market operations and regional transmission planning. FERC Orders 888 and 2000 (passed in 1996 and 1999, respectively) also encouraged the creation of Independent System Operators (ISOs), such as ISO-NE, to coordinate and operate the transmission grid in a deregulated market. Subsequent FERC orders have levied additional planning and operational requirements on ISOs; in this way FERC wields both direct and indirect influence on transmission investments in the region. Key FERC orders

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[30] **Federal Energy Regulatory Commission**, *What FERC Does*, https://www.ferc.gov/what-ferc-does

impacting GETs deployment in New England include Order 1000, Order 881, and most recently Orders 1920-A and 2023.

- **FERC Order 1000:** This order was issued in 2011 and marked a major shift in transmission planning and cost allocation by requiring regional planning processes to consider public policy requirements, ensure stakeholder participation, and allow for competitive bidding in transmission development. This order laid the groundwork for more integrated and transparent planning efforts within ISO-NE and across the country, including LTTP. It also emphasized the importance of regional collaboration, which is particularly relevant for Maine given its potential to export renewable energy to neighboring states and its reliance on coordinated infrastructure investment.
- **FERC Order 881:** Passed in 2021, 881 requires ISO's to "establish and maintain systems and procedures necessary to allow transmission owners that would like to use dynamic line ratings the ability to do so."[31] More specifically it requires operators to use adjusted line ratings accounting for ambient conditions (temperature, solar heating, wind) in Day-Ahead and Real-Time markets. While 881 does not mandate DLR adoption, it does highlight the potential for DLRs to improve transmission line utilization and lower costs, and these Ambient Adjusted Ratings reporting requirement facilitates DLR deployment.
- **FERC Order 2023:** Adopted in 2023, this order was designed to streamline the generator interconnection process, reducing bottlenecks that have historically delayed new projects in Maine and elsewhere. Specifically, it requires transmission providers to adopt a First-Ready, First-Served cluster study process and implement standardized procedures to streamline interconnection across regions. Additionally, Order 2023 requires evaluation of advanced transmission technologies, including GETs, when conducting cluster studies to determine if these technologies could provide a lower-cost pathway for resource interconnection.
- **FERC Orders 1920, 1920-A and 1920-B:** Adopted in 2024, Orders 1920, 1920-A and 1920-B mandate proactive, long-term regional transmission planning that accounts for future scenarios such as decarbonization, state policies and resource plans, and load growth – pressures that are increasingly relevant to Maine as it seeks to integrate offshore wind and rural renewable generation. Additionally, these orders include specific provisions related to the consideration of GETs. GETs and other advanced transmission technologies must now be evaluated alongside traditional solutions as part of regional transmission planning processes.

These FERC Orders place additional responsibility on ISO-NE to effectively and efficiently incorporate GETs into its planning toolkit. For Maine, where long permitting timelines and

[31] ***Federal Energy Regulatory Commission**, FERC Rule to Improve Transmission Line Ratings Will Help Lower Transmission Costs,* [*https://www.ferc.gov/news-events/news/ferc-rule-improve-transmission-line-ratings-will-help-lower-transmission-costs*](https://www.ferc.gov/news-events/news/ferc-rule-improve-transmission-line-ratings-will-help-lower-transmission-costs)

challenging terrain can delay new transmission builds, the incorporation of GETs could offer cost-effective and timely solutions to increase transfer capacity and improve grid flexibility.

### *Regional: ISO New England*

As the market operator, ISO New England (ISO-NE) is responsible for bulk electric system transmission planning in the New England region.[32] The Maine Public Utilities Commission retains authority over siting and permitting for new facilities within Maine's borders, but ISO-NE is charged with identifying new bulk transmission needs and evaluating solutions. In line with FERC Orders 1920, 1920-A and 1920-B as well as the ISO-NE LTTP tariff, these solutions would need to be evaluated in a 20-year planning horizon, account for a range of future scenarios, and evaluate GETs alongside other transmission solutions. In line with these directives, ISO-NE issued an RFP in early 2025 soliciting proposals for new transmission resources in Maine, including an upgrade to the Maine-New Hampshire interface and network upgrades near Pittsfield that can help accommodate an incremental 1,200 MW of onshore wind deployment.[33]

Most of Maine is within ISO-NE territory.[34] However, in the northeastern part of the state, Versant's Maine Public District is not connected to the broader ISO-NE system nor is it part of an ISO-NE dispatch zone.[35] [36] This creates special considerations for grid planning, including GETs evaluation.

### *State: Maine Public Utilities Commission*

Beyond the federal and regional entities that regulate and manage transmission needs identification and approvals, the State of Maine has a critical role to play as well. The Maine Public Utilities Commission (MPUC) regulates the planning, investment, and operation of T&D infrastructure within the state. As discussed above, transmission planning and siting is conducted in collaboration with ISO-NE, with additional input from state agencies such as the Department of Environmental Protection. On the distribution side, the MPUC oversees utility planning processes, and the IOUs are required to submit Integrated Grid Plans that account for load growth, reliability, and align with state energy policies. Public Law 2021, Chapter 702 (An Act Regarding Utility Accountability and Grid Planning For Maine's Clean Energy Future) sets the grid planning process requirements for Maine utilities.[37] By law, the plans submitted to the MPUC must include the following:

- An assessment of the utility's electrical system
- Customer energy consumption and usage characteristics

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[32] ***ISO New England***, *About ISO New England, https://www.iso-ne.com/about*
[33] ***ISO New England,*** *ISO-NE issues request for proposals for transmission solutions, https://isonewswire.com/2025/04/01/iso-ne-issues-request-for-proposals-for-transmission-solutions/*
[34] ***ISO New England***, *Maps and Diagrams, https://www.iso-ne.com/about/key-stats/maps-and-diagrams*
[35] ***ISO New England***, *Maps and Diagrams, https://www.iso-ne.com/about/key-stats/maps-and-diagrams*
[36] ***Versant Power***, *Responses to EMEC 1st Set Re: 2024-2025 MPD Update, https://www.versantpower.com/docs/default-source/emec-1st-set---24-mpd/versant-responses-to-emec-1st-set-re-2024-2025-mpd-update.pdf?sfvrsn=111d54e4_1*
[37] ***Maine Legislature***, *SP0697, Item 19, 130th Legislature, https://legislature.maine.gov/legis/bills/getPDF.asp?paper=SP0697&item=19&snum=130*

- A minimum of two planning scenarios, including a baseline scenario and a high-penetration distributed energy resource and end use electrification scenario.
- Load forecasts and supply assessments
- Analysis of hosting capacity, including locational benefits of distributed energy resources and areas of existing or potential congestion
- Analysis of available and emerging technologies to enable load management and flexibility
- Assessments of environmental, equity, and environmental justice impacts of grid plans
- Identification of cost-effective near-term grid investments and operations needed to meet published PUC goals

The MPUC is required to initiate a grid planning process proceeding every five years, with stakeholder engagement to identify priorities for the plans to address. These IGPs serve as a strategic framework to guide long-term utility planning; however, they do not guarantee cost recovery for identified plans; that determination happens during subsequent regulatory proceedings, primarily rate cases.

MPUC also has jurisdiction over the local electric distribution system.[38] Electric utilities operating in Maine must comply with MPUC regulations, and the MPUC publishes an annual report outlining its analysis of the Maine electrical system, markets, and operations.[39] Further, MPUC oversight at the distribution level focuses on ensuring that planning supports reliability, affordability, and the integration of distributed energy resources (DERs) such as solar, battery storage, and electric vehicles. Between utility Integrated Grid Plans (IGPs) and direct distribution level investment approvals, the MPUC has a number of levers that could be used to facilitate GETs evaluation and deployment. These could include:

- A mandate for utilities to evaluate GETs as part of their distribution system planning processes, similar to how they must consider non-wires alternatives (NWAs)
- Incorporation of GETs into grid modernization plans
- Clarification around cost recovery pathways for GETs through rate cases or performance-based regulation

### *Regulatory Summary*

In summary, T&D planning in Maine – and in the US more broadly – is governed by a number of different regulatory bodies and planning entities. GETs have seen increasing regulatory support in recent years, at both the federal and local levels, though deployment in most cases remains small scale. With that regulatory context in place, this next section provides an overview of the current

[38] ***Maine Public Utilities Commission***, *About the Commission*, https://www.maine.gov/mpuc/about
[39] ***Maine Public Utilities Commission***, *2024 Annual Report*, https://www.maine.gov/mpuc/sites/maine.gov.mpuc/files/inline-files/2024%20Annual%20Report%20Final_0.pdf

transmission network in ISO-NE, as well as some active transmission planning efforts underway in the region.

## Transmission Network and Active Planning Efforts in ISO-NE

### *Transmission Network Overview*

The ISO New England (ISO-NE) transmission system is a highly integrated, high-voltage network that spans six states and serves over 14 million people. It includes more than 9,000 miles of transmission lines and is designed to reliably deliver electricity across a diverse geography, connecting centralized generation resources, including fossil, nuclear, hydro, and growing renewable assets, to load centers. The system is managed by ISO-NE to ensure real-time reliability, support efficient wholesale markets, and plan for future infrastructure needs.

ISO New England (ISO-NE) is also electrically connected to neighboring regions through a network of interties that enable the import and export of electricity across regional borders. These interties link ISO-NE to New York (NYISO), Quebec (Hydro-Québec), and New Brunswick (NB Power), providing critical access to external resources that support system reliability, capacity needs, and economic power transfers. Key connections include the Phase II HVDC tie with Quebec, which enables large-scale power flows from Canadian hydro resources, and multiple AC and DC ties with New York and New Brunswick. These interregional links allow ISO-NE to manage supply and demand more flexibly, access lower-cost or cleaner energy sources, and respond to emergencies or extreme weather conditions. As regional coordination becomes more important for integrating renewables and maintaining reliability, these interties are increasingly valuable assets in New England’s energy system.

Maine’s specific transmission network is a mix of high-voltage lines that connects remote generation resources – such as hydro, biomass, and increasingly wind and solar – to population centers within the state and to the broader ISO New England grid. Maine’s transmission topology includes two distinct regions: the region connected to ISO-NE and serving around ~95% of Maine’s total load[40], and the Northern Maine Public Power District.

The ISO-NE region consists of a 345 kV backbone running roughly north-south (from the New Hampshire border up to Orrington, and branching out to points in Downeast Maine and toward New Brunswick) and an extensive 115 kV network that covers the rest of the state. Much of Maine’s internal load is served by 115 kV lines, some of which operate as long radial lines feeding remote towns and communities. This part of the network is often described as a “tail” or radial extension of the New England grid – meaning power flows primarily along a few main pathways, with fewer networked alternatives than in southern New England. In the context of GETs, these radial lines could benefit from DLRs, as they would allow these critical lines to carry additional capacity. TOs and APFCs, on the other hand, would likely be less impactful due to the limited availability of alternative power flow configurations resulting from the absence of other lines. The exception to this

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[40] ***U.S. Energy Information Administration****, Maine State Electricity Profile,* https://www.eia.gov/electricity/state/maine/

configuration occurs in the more densely populated southeastern region of Maine where there is a more networked grid which could benefit from power the power flow rerouting made possible by TOs and APFCs. The northern ends of the 345 kV backbone interconnect with the New Brunswick grid via the Keene Road – Keswick transmission line and the Orrington – Point Lepreau transmission line. These connections facilitate the transfer of power between New Brunswick and the ISO-NE market; for example, New Brunswick participates in the ISO-NE forward capacity auction.

The Northern Maine Public Power District is not electrically interconnected with the rest of ISO-NE. Located in the far north in Aroostook County and served by Versant Power, this region covers around ~5% of Maine's total load[41] and is a wind-rich region with no direct AC connections to the rest of ISO-NE. Instead, the region has two low-voltage tie lines to New Brunswick through which northern Maine behaves as a radial link to New Brunswick's grid.[42] This portion of Maine's grid is operated by the Northern Maine Independent System Administrator (NMISA).

In addition to existing interties, one major intertie between New England and Quebec is currently under-construction – the New England Clean Energy Connect line (NECEC).[43] This is a 320 kV HVDC line from Quebec to an interconnection point near Beattie Township and Lewiston, and is expected to deliver up to 1,200 MW of hydroelectric power into the ISO-NE system starting in 2026. This will serve as a major new source of clean power, benefitting Maine and the broader region, while also putting further pressure on some already congested interfaces to the south, between Maine and New Hampshire.

### *Transmission Planning in ISO-NE*

Up until recently, the ISO-NE transmission planning paradigm centered on reinforcing and updating the existing grid to alleviate congestion and ensure reliability. Since the mid-2000s ISO-NE's transmission network has been undergoing continuous modest expansion and modernization to meet reliability needs identified in Regional System Plans. Since then, New England ratepayers have funded over $10 billion in upgrades such as new 345 kV lines, substation expansions, and improved ties between states. Examples of such projects include the New England East–West Solution (connecting southern New England), the Greater Boston upgrades, and Maine's own Maine Power Reliability Program (MPRP).

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[41] ***Find Energy***, *Aroostook County Electricity, https://findenergy.com/me/aroostook-county-electricity/*

[42] *This topological division may soon change, however. To meet their climate goals, states within New England have identified the remote regions of northern and western Maine as key sites for onshore wind development. As a result, large 345 kV lines have been proposed to interconnect this region to the broader ISO-NE grid. In 2021, Maine enacted legislation directing the Public Utilities Commission (PUC) to facilitate a competitive procurement for transmission solutions supporting northern Maine wind projects in Aroostook County. After a few false starts, this appears to be gaining traction: in October 2024, CMP announced plans to bid on a northern Maine transmission project, supported by $425 million in federal funding from the U.S. Department of Energy's Grid Deployment Office. This proposed 100-140 mile lone 345 kV line would transmit up to 1,200 MW of wind power from a new substation near in northern Maine to existing substations in central Maine, effectively connecting northern Maine to the rest of New England.*

[43] ***ISO New England***, *NECEC Operating Agreements Presentation, https://www.iso-ne.com/static-assets/documents/100017/a04_tc_necec_operating_agreements_presentation.pdf*

However, in recent years there has been a shift in transmission planning that not only prioritizes reducing congestion and maintaining reliability but also enabling the region's decarbonization goals. New England states, including Maine, have decarbonization targets which incentivize the integration of renewable energy resources and increased electrification of heating and transportation. The existing transmission system was built mostly to connect large, central fossil and nuclear plants and needs reconfiguration to connect these more location constrained and remote renewable resources while also accommodating an increase in load.

Recognizing this evolution in prioritization, ISO-NE responded to a 2020 call from the New England States Committee on Electricity (NESCOE) to develop a long-term transmission planning approach that incorporates state climate goals.[44] ISO-NE developed a Longer-Term Transmission Planning (LTTP) tariff that integrates state objectives with the traditional transmission procurement process.[45] In particular, the LTTP incorporates evaluation metrics such as environmental impacts and siting constraints in determining transmission needs, alongside traditional cost-benefit tests to ensure alignment between state prerogatives and broader regional planning objectives. Maine is a key player in regional collaborations such as NESCOE. NESCOE members – who are appointees of the governors of each New England state – advocate for state energy goals in regional planning processes. In this way, Maine plays a significant role in shaping both T&D investments in the region.

The first study from this planning process was the 2050 Transmission Study which provided a high-level roadmap of what a decarbonized grid might require for transmission infrastructure.[46] Following the recommendations from this study, ISO-NE and NESCOE issued their first 2025 Longer-Term Transmission Planning Request for Proposals (the "2025 LTTP RFP") in April 2025.[47] The initial focus from the studies and the RFP is to strengthen the Maine-New Hampshire interfaces to enable north-to-south power flow. This evolution in transmission planning highlights a shift toward proactively addressing the region's future transmission needs, aligning grid reliability investments with state decarbonization targets, and anticipated changes in electricity generation and demand.

## Key Drivers of Transmission Investment Needs in Maine

Looking ahead, there are a number of likely drivers of T&D investment on the horizon in Maine. GETs may be able to play a role in filling some of these needs, though investment in conventional transmission upgrades and additions will likely also be needed. Key drivers include:

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[44] **ISO New England**, *Longer-Term Transmission Studies, https://www.iso-ne.com/system-planning/transmission-planning/longer-term-transmission-studies/*

[45] **New England States Committee on Electricity,** *New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid, October 2020. https://nescoe.com/wp-content/uploads/2020/10/NESCOE_Vision_Statement_Oct2020.pdf*

[46] **ISO New England**, *2050 Transmission Study Final, https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf*

[47] **ISO New England**, *2025 LTTPRFP Posting Announcement, https://www.iso-ne.com/static-assets/documents/100021/2025lttprfp_postingannouncement.pdf*

- **Asset Condition Projects:** This refers to grid infrastructure that is reaching the end of its useful life and needs to be replaced, either in-kind or with a new solution
- **Renewable Resource Integration:** In order to realize Maine's renewable generation potential, substantial investment in transmission infrastructure will likely be needed to deliver that power to load centers
- **Load Growth:** Electrification of building energy demand and transportation are likely to drive significant load growth in the coming decades, which will necessitate new transmission development to serve those loads and maintain reliability
- **Resiliency and Extreme Events:** Climate change is likely to increase the frequency of extreme weather events that may impact the Maine economy. Transmission investments may be needed to make the electrical grid more resilient to such events.
- **Alleviation of Major Interface Bottlenecks:** Finally, some interfaces in Maine may serve as singular bottlenecks for power delivery; investments to help alleviate these interfaces may be needed.

Each of these drivers is discussed in greater detail below.

### *Asset Condition*

Many transmission lines in Maine were built in the mid-20th century and are reaching end-of-life, requiring reinvestment and asset modernization. To address these challenges, some Maine utilities have already invested heavily in replacing and upgrading transmission assets to ensure reliability. For instance, Central Maine Power (CMP) completed the Maine Power Reliability Program (MPRP) between 2010 and 2015 – a $1.4 billion project upgrading or adding over 400 miles of lines and multiple substations statewide.[48,49] Many near-term asset condition needs remain, however, and this is likely to continue to be a priority for transmission investment over the coming decades.

In New England, the transmission asset replacement process starts with each transmission owner assessing the condition of its lines, cables, towers, and substations, and reporting the information to ISO-NE's Asset Condition List.[50] When equipment is at end-of-life or poses a reliability risk, the transmission owner proposes an asset condition project. These projects are reviewed by ISO-NE to confirm they do not adversely impact the regional grid and are added to the Regional Transmission Plan.[51] Asset replacements usually address existing facilities without changing fundamental power

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[48] **Central Maine Power**, *Maine Power Reliability Program Reaches New Milestones, https://www.cmpco.com/w/cmps-maine-power-reliability-program-reaches-new-milestones*

[49] **ISO New England**, *MPRP 2014 Cost Update, https://www.iso-ne.com/static-assets/documents/2015/03/mprp_2014_cost_update.pdf*

[50] **ISO New England**, *RSP Project List and Asset Condition List, https://www.iso-ne.com/system-planning/system-plans-studies/rsp/rsp-project-list-and-the-asset-condition-list*

[51] **ISO New England**, *Regional System Plan (RSP), https://www.iso-ne.com/system-planning/system-plans-studies/rsp*

flow patterns and if approved, utilities are allowed to proceed with these upgrades to their own assets.

The costs of asset replacement projects at 115 kV or above are a part of the Pool Transmission Facilities (PTF) and are typically socialized across New England, including a portion paid by Maine ratepayers for all asset condition projects across the region, as regulated by the ISO-NE tariff and FERC.[52] Asset replacement projects that are below 115kV are replaced by the utility managing those lines and paid by ratepayers after approval from the MPUC.

### *Renewable Resource Integration*

Maine has some of the most valuable renewable energy resources in New England, particularly onshore wind in the northern and western parts of the state and significant offshore wind potential in the Gulf of Maine. Interconnecting these resources is critical not only for Maine to achieve its Renewable Portfolio Standard (RPS) targets, but also for neighboring New England states to meet theirs. Interconnecting these renewable resources, which are distinct in both how and where they generate power, requires reconfiguring a grid originally built for legacy energy sources.

GETs - particularly DLRs - could support this transition by increasing the capacity of both new and existing lines during periods of high wind generation, enabling greater renewable exports without triggering thermal overload constraints.

### *Load Growth*

Over the last two decades, New England's net electricity usage has been flat or even declining thanks to energy efficiency and behind-the-meter solar generation offsetting load growth. Moving forward, however, electricity demand across the region is expected to rise after years of stagnation. In Maine, this change is already taking shape as heating and transportation electrification policies take effect. According to the ISO-NE's 2025-2034 Forecast Report of Capacity, Energy, Loads, and Transmission, Maine is expected to see a 73.6% increase in gross peak load forecast (not including behind-the-meter resources such as rooftop solar) shifting from a summer peaking 2,217 MW system to a winter peaking 3,849 MW system.[53] This anticipated load growth is increasing the need for transmission capacity expansion, making it one of the major drivers of T&D investments in Maine .[54]

DLRs could help mitigate some of these transmission expansion costs. DLRs are particularly well-suited to winter-peaking systems like Maine's projected future grid, as the highest electricity demand is expected during the coldest days – conditions under which DLRs typically allow for significantly higher transmission line capacity.

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[52] ***ISO New England***, *Transmission Cost Allocation, https://www.iso-ne.com/system-planning/transmission-planning/transmission-cost-allocation/*
[53] ***ISO New England***, *2025 CELT Report, https://www.iso-ne.com/static-assets/documents/100023/2025_celt.xlsx*
[54] ***Efficiency Maine***, *Beneficial Electrification Plan, https://www.efficiencymaine.com/docs/TPVI_Appendix-H_Beneficial-Electrification-Plan.pdf*

### *Resiliency and Extreme Events*

Maine's grid has historically faced challenges related to extreme weather events which are particularly pronounced due to its aforementioned "tail" or radial nature in which power flows primarily along a few heavily forested main pathways. Frequently falling trees caused by wind or ice storms are a well-known cause of line failure where a single break can cut off entire communities to sections of Maine's grid with few redundancies.[55] Moreover, as severe storm intensity and frequency are increased, due to the effects of climate change, these extreme weather event challenges are expected to increase.

Furthermore, these challenges will become even more pressing as Maine electrifies its building heating systems, emphasizing the need for grid resiliency and reliable service during severe winter storms to prevent cold-weather risks for communities. All these points underscore that extreme weather resilience is and will continue to be a major component of T&D investments in Maine. Planners can address some of these challenges through a mix of infrastructure hardening, resilience-oriented infrastructure expansion, and the application of "smart" grid technologies such as GETs and VPPs.

Hardening infrastructure measures include replacing wooden poles with stronger materials (steel or fiberglass), installing "tree-resistant" covered wires, upsizing pole diameters to better handle high winds, elevating critical substations and control equipment to avoid flooding, and more aggressive vegetation management programs around transmission corridors. In addition, adding redundancy in network upgrades by looping radial lines and adding alternate feeder lines can increase the optionality of power flow pathways in the network. These more networked configurations could enable GETs such as APFCs and topology optimization software to more optimally reroute power when a line goes down, potentially avoiding costly outages.

VPPs allows customers with installed batteries to benefit from backup power even when grid failures occur due to line outages. Moreover, if strategically placed and pooled together, remote isolated communities frequently affected by severe weather events can fulfill their own electricity needs by behaving as neighborhood microgrids, a significant resiliency benefit for those communities.

Public policy funding for these projects have emerged in the last several years. In 2024, Governor Janet Mills announced the creation Maine Grid Resilience Grant Program which "seeks to increase the resilience of the electric grid and Maine communities while increasing clean energy workforce opportunities and aligning with ongoing electric grid modernization and state climate goals". This program is funded by a $2.2 million per year grant until 2026 provided by the federal Bipartisan Infrastructure Law via the Grid Resilience Formula Grant Program.[56] Additionally, in 2023 the Bipartisan Infrastructure Law also awarded CMP with $30 million to deploy smart grid technologies

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[55] ***Central Maine Power***, *Tree Care*, https://www.cmpco.com/outages/weareready/treecare?utm_source=chatgpt.com
[56] ***Maine Governor's Energy Office***, *Grid Resilience Initiatives*, https://www.maine.gov/energy

via the Grid Resilience and Innovation Partnerships (GRIP) led by the DOE's Grid Deployment Office (GDO).[57]

### *Alleviation of Major Interface Bottlenecks*

Maine's transmission network faces critical constraints that limit power transfers both within the state and to the broader New England region. ISO-NE's recent studies, such as the 2050 Transmission Study, explicitly recognize the following two critical interfaces:

#### The Orrington–South interface:

This interface, located near Bangor, ME, connects New Brunswick to the rest of New England through eastern Maine. Historically, it was limited to approximately 1,325 MW, which significantly restricted the ability to export renewable energy generated in northern and eastern Maine. Upgrades completed as part of the Maine Power Reliability Program (MPRP) have incrementally increased the transfer capability to approximately 1,650 MW, providing some relief to existing congestion. However, these upgrades did not enable the qualification of any new capacity resources north of the Orrington–South interface. When accounting for existing capacity resources, no headroom remained to accommodate additional capacity, meaning this interface continues to serve as a key barrier to large-scale renewable integration – particularly for onshore wind development in Aroostook County and potential hydro energy imports from New Brunswick.[58]

#### The Maine–New Hampshire (ME–NH) interface:

A major bottleneck connecting southern Maine's transmission grid to New Hampshire and the rest of ISO-NE. Currently, this interface has a maximum transfer capacity of about 2,000 MW (increased from 1900 MW in June 2024), which is often fully utilized under conditions of high renewable output. Once the New England Clean Energy Connect (NECEC) project is completed the transfer limit of this interface will rise to 2,200 MW.[59] As Maine aims to significantly increase renewable generation capacity, this limitation could become increasingly problematic, effectively isolating Maine's renewable resources from the primary load centers in southern New England.

Resolving the Orrington–South and ME–NH interface constraints require targeted transmission upgrades or entirely new infrastructure. Potential solutions include upgrading existing transmission lines, constructing new parallel lines, or implementing GETs.

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[57] **Central Maine Power**, *CMP Wins $30M Smart Grid Technology Grant,* https://www.cmpco.com/w/cmp-wins-30m-smart-grid-technology-grant

[58] **ISO New England**, *FERC Order Accepting 6th Forward Capacity Auction Information,* https://www.iso-ne.com/static-assets/documents/regulatory/ferc/orders/2012/mar/er12_757_3_15_12_order_accept_6th_fca_info.pdf

[59] **ISO New England**, *Post-NECEC Maine Transfer Limits,* https://www.iso-ne.com/static-assets/documents/100018/a07_2024_12_18_post_necec_maine_transfer_limits.pdf

### *Cost and Implementation of Proposed Necessary Upgrades*

The 2050 Transmission Study provides a rough estimate of the costs required to develop the transmission system for 2050 as proposed. The roadmap recommends targeting four *high-likelihood concerns* areas:

1. The Maine-New Hampshire and North-South transmission interfaces that connect Maine and New Hampshire to northeastern Massachusetts
2. The Boston Import interface is expected to require upgrades due to electrification of heating and electric vehicle adoption
3. Northwestern Vermont around Burlington
4. Southwest Connecticut

The estimated final cost for transmission upgrades related to the study is in between $16-26 billion depending on the range of potential winter peaks varying in between 51-57 GW. These costs would be spread out over a 25-year period between now and 2050, meaning that the estimated yearly costs are $0.62 and $1.00 billion per year. Many of the lines highlighted in the project also overlap with asset condition needs.[60]

The Aroostook County to ISO-NE transmission line is currently in the second iteration of the RFP process, so final costs are not yet known. The original project, selected through an RFP issued in November 2021, was estimated to cost $2.78 billion, with Maine ratepayers expected to fund approximately 60% of the total. That proposal was however terminated in December 2023 due to supply chain constraints, rising costs, and other challenges. To help reduce the financial burden on ratepayers in the current iteration, the U.S. Department of Energy awarded a $425 million capacity contract to Avangrid, the parent company of Central Maine Power. Additional details on this project can be found in Appendix B of this report.[61,62,63+]

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[60] ***ISO New England****, 2050 Transmission Study Final,* [*https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf*](https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf)

[61] ***Maine Public Utilities Commission****, Order Selecting Projects and Approving Term Sheets, Docket No. 2021-00369 (Nov. 29, 2022), https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2021-00369*

[62] ***Maine Public Utilities Commission****, Order Terminating Northern Maine Procurement, Docket No. 2021-00369 (Dec. 22, 2023), https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7b10443C9C-0000-CF1C-A91C-B5EF5F6D8A36%7d&DocExt=pdf&DocName=%7b10443C9C-0000-CF1C-A91C-B5EF5F6D8A36%7d.pd*

[63] ***Maine Public Utilities Commission****, Order Directing New Procurement Process, Docket No. 2021-00369 (May 17, 2024), https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7b1047928C-0000-C915-85C1-DE73B07A9304%7d&DocExt=pdf&DocName=%7b1047928C-0000-C915-85C1-DE73B07A9304%7d.pdf*

# Section 4. Use Cases for GETs in Maine

As Maine faces increasing demands on its electric grid, GETs such as DLRs, PFCs, and TO, as well as other emerging technologies that provide similar grid benefits, such as VPPs, present a strategic opportunity to optimize system performance and defer costly infrastructure investments. This section outlines potential use cases for deploying GETs in Maine, focusing on applications that directly address the state's most pressing transmission challenges. By targeting specific grid needs – such as peak load growth, renewable integration, aging infrastructure support, and extreme weather preparedness – these use cases discuss both the potential benefits and limitations of GETs, and how they may be leveraged to support long-term energy and policy objectives.

Additionally, E3 conducted two illustrative analyses examining hypothetical deployments of both DLRs and VPPs, to further illustrate how these technologies could help meet transmission system needs in Maine. Though not derived from detailed modeling,[64] these analyses explore specific deployment scenarios, leveraging findings from other studies to estimate indicative costs and benefits. These are detailed in the "Illustrative Analysis" section below.

## Use Case Discussion

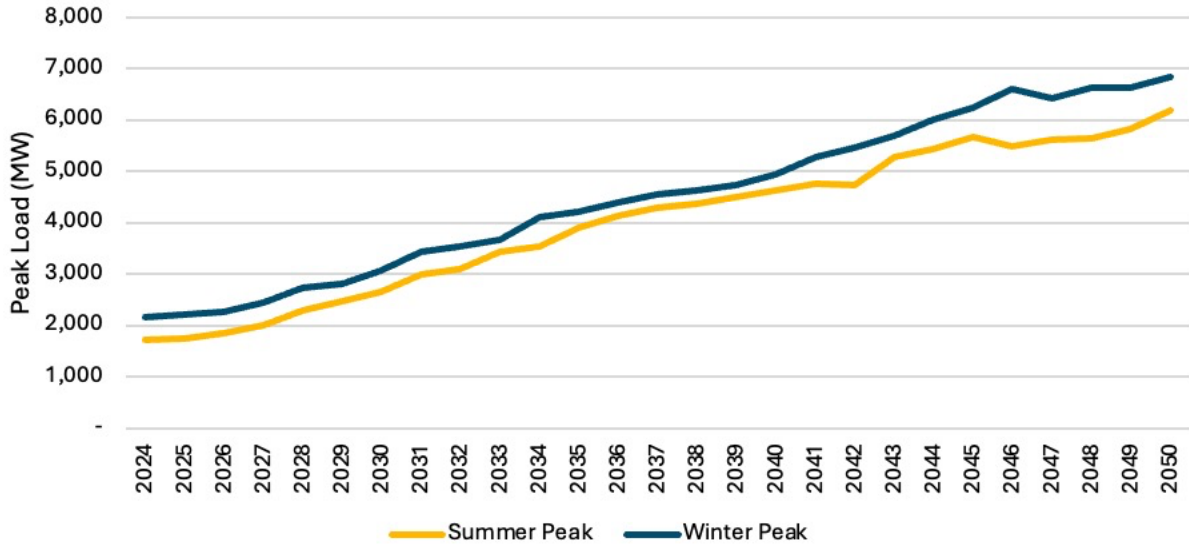
As discussed in Section 3, there are a number of factors likely to drive substantial transmission investment need in Maine in the coming years. The discussion here builds on that summary by discussing how GETs could help meet some of those needs, and where conventional solutions may be more appropriate.

**Managing Peak Demand Growth and Seasonal Shifts**

Maine's peak demand is projected to rise substantially in the coming decades due to increased electrification of heating and transportation systems. In addition to overall growth, the grid must adapt to new seasonal demand patterns. Today, Maine is dual peaking, meaning the summer and winter peak load requirements are roughly equivalent. Further deployment of electric heat pumps is likely to push the system to a more consistent winter peak, a seasonality shift that the grid must be able to support. A projection of peak load growth in Maine from E3's in-house Market Price Forecasting model is included in Figure 5 below:

[64] *Importantly, this study did not involve any production cost analysis which would be required before any form of deployment or solicitation could be considered.*

***Figure 5:** Peak Load Projection for Maine*[65]




While overall growth is substantial, year-to-year peak growth is incremental. Gigawatt scale increases will ultimately require new and upgraded transmission lines to maintain reliable grid service. However near-term incremental growth may be mitigated by lower-cost solutions such as GETs. DLRs, for example, can unlock additional capacity on existing lines by adjusting transmission ratings in real time based on ambient temperature, wind speed, and solar radiation. This could allow for higher line utilization during cold weather, coinciding with Maine's shift to a fully winter peaking system, and potentially deferring the need for new line additions. VPPs may be able to achieve a similar deferral benefit by reducing peak loads in targeted areas of the grid – this idea is further explored in the VPP Deployment analysis discussed below.

The challenge will be ensuring that deferral of new line investments will be long enough to offset the costs of any deployed non-wires alternative (whether a GETs solution, VPP, or otherwise). Given the rate of expected peak load increases, this will require detailed study before any deployment should be considered.

**Supporting Integration of Renewable Resources**

Maine boasts some of the best renewable resources in New England, particularly onshore wind in the northwestern and far northern portions of the state. These resources will be increasingly valuable to Maine and the broader New England region as the states pursue deep decarbonization. However, integrating these resources into the grid will require transmission investments to ensure both deliverability and economic dispatch.

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[65] *2024 E3 Market Price Forecast, ISO-NE*

GETs may be able to support renewable integration by enhancing system flexibility. For example, advanced power flow control devices can redistribute power across the network to avoid localized overloads and allow more renewable energy to flow through the system. Automated voltage regulation and real-time system visibility tools can also stabilize the grid amid fluctuations in renewable output. These capabilities may provide particular benefits in Maine's remote areas, where wind potential is high but grid infrastructure is limited. DLRs may also be able to increase the transfer capacity of existing lines, enabling additional deliverability – this idea is also further explored in the illustrative analysis below. By using GETs to optimize transmission corridors, the state may be able to improve renewable utilization and minimize curtailment, while deferring some higher cost transmission builds.

**Replacing and Upgrading Aging Infrastructure**

Much of New England's transmission infrastructure was built decades ago and is approaching or has exceeded its expected service life. Maine is no exception, with aging substations, transformers, and overhead lines in need of reinvestment to maintain reliability. Traditional asset replacement programs can be expensive and labor-intensive, and prioritizing investments becomes increasingly complex as system demands evolve.

While GETs cannot avoid the need for asset condition investments, they may be able to assist in targeting and optimizing which assets to focus on for replacement. For instance, monitoring technologies, such as line sensors and transformer diagnostics[66], can provide real-time condition data that allows utilities to prioritize upgrades based on actual equipment performance and loading rather than age alone. Additionally, GETs may be able to be strategically deployed to relieve stress on some aging infrastructure, extending its useful life while long-term replacement plans are developed. This data-driven approach can improve the efficiency and impact of Maine's limited capital resources and allow for better alignment with state policy goals.

**Navigating Right-of-Way Constraints and Community Resistance**

One of the most significant barriers to traditional transmission expansion in Maine is the challenge of siting new lines. Terrain, environmental concerns, and strong community opposition – especially in scenic and rural areas – make acquiring new rights-of-way difficult. These constraints increase costs and often delay or prevent needed projects.

GETs can offer a compelling non-wires alternative by maximizing the use of existing infrastructure. Deploying GETs carries lower permitting risk, and may also help maintain community support for grid upgrades by minimizing visual and environmental impacts. In addition, deploying GETs can serve as a bridge solution – extending the capacity and performance of the current grid while longer-term siting and construction challenges are addressed.

**Enhancing Resiliency Against Extreme Events**

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[66] *These are commonly deployed as part of DLR solutions*

Maine's grid is increasingly vulnerable to extreme weather events, including ice storms, high winds, and flooding. These events are projected to become more frequent and severe with climate change. GETs can enhance system resilience in several ways. Real-time monitoring and control technologies can detect and respond to line overloads, faults, or abnormal conditions faster than conventional systems. Topology optimization can dynamically reconfigure the grid during emergencies to isolate faults and maintain service to critical loads. Power flow control devices can help maintain voltage and frequency stability in the event of unexpected disruptions. Collectively, these tools allow the grid to adapt to rapidly changing conditions, minimize outages, and restore service more quickly – especially important in remote or weather-prone areas of Maine. These are benefits that are also notoriously difficult to quantify in a planning study context. A challenge with deploying GETs under this use case will be in aligning on a method for quantifying the resilience benefits that GETs and competing solutions provide to the grid.

In summary, if deployed in the right circumstances and evaluated against alternate options, these technologies may be able to address multiple critical grid priorities in Maine, deferring more costly investments and yielding benefits to ratepayers. At the same time, the scale of peak load growth, renewable integration needs, and asset condition replacements are likely to be too large to be fully or primarily met with GETs, and the Maine grid will require substantial investment in conventional transmission solutions in the years to come as well. As needs arise, it is critical that planners in Maine and at ISO-NE effectively assess all options, and leverage GETs whenever those solutions are able to meet current and near-future needs for the lowest cost. The following section explores in more detail two potentially advantageous deployment options, illustrating potential benefits these solutions could provide in Maine.

## Illustrative Analysis of potential DLR and VPP Applications

To illustrate the deployment use cases and potential benefits of GETs in Maine, E3 conducted two illustrative analyses to examine: (1) DLR deployment for wind integration and congestion relief, and (2) VPP deployment for peak reduction and transmission deferral benefits. Each of these analyses is described in more detail in the proceeding sections.

### *DLR Deployment for Wind Integration and Congestion Relief*

To estimate the potential benefits of deploying DLRs for wind integration and congestion relief, E3 conducted analysis following the steps below:

1. **Examination of topology, prices, and wind dispatch:** Initial screening of high-voltage transmission lines and distribution of wind generation facilities in Maine to narrow the scope of analysis to lines that could potentially benefit from DLR integration.
2. **Estimation of transmission investment benefits:** Development of assumptions around line ratings benefits from DLRs and potential wind curtailment reduction benefits along particular transmission corridors.

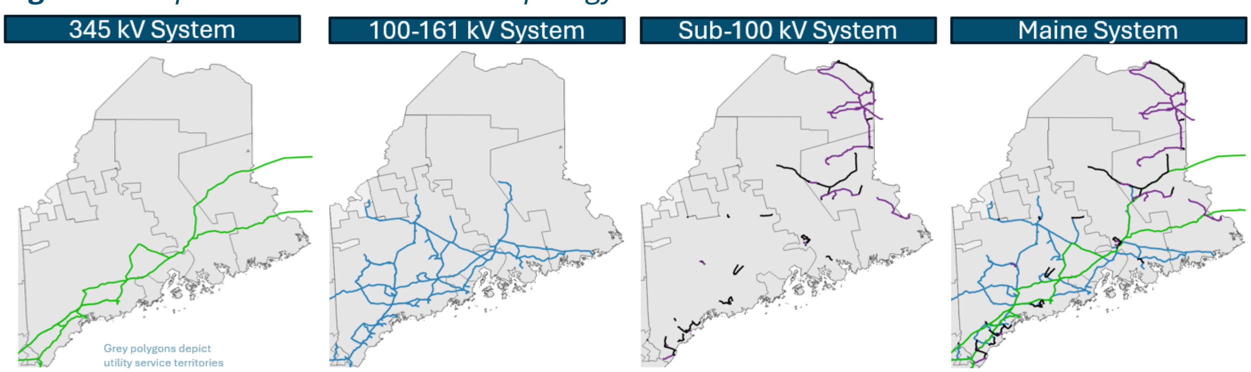
3. **Evaluation of alternative congestion alleviation solutions:** Review of existing proposals to upgrade several illustrative transmission corridors[67] that currently serve to deliver remote wind resources to load centers.
4. **Assessment of DLR impacts on candidate Maine lines:** Analysis of DLR impacts on line transfer capability, extrapolated from empirical research conducted in similar markets.
5. **Benefit-cost comparison:** Comparison of the benefit of implementing DLR in terms of congestion relief relative to the costs of the DLR installation.

It is critical to note that the scope of this analysis did not involve production cost modeling of DLRs or alternative solutions; rather this assessment aims to provide an illustration of potential benefits based on findings from similar deployments in other regions, and E3's experience evaluating high-renewable penetration grids. As discussed further at the end of this section, additional study would be required for investment or deployment.

## *Examination of Topology, Prices, and Wind Dispatch*

As discussed in Section 3, the Maine transmission network is comprised of three interconnected sub-networks: a 345 kV "spine" running from the interconnections with New Brunswick towards New Hampshire and extending to Boston, a 115 kV radial network connecting the population centers along the coast and in the northwest, and a sub-100 kV system mostly concentrated in the low-density northeast.  Below are a series of maps depicting these systems[68].

***Figure 6:*** *Maps of the Transmission Topology in Maine*




While there is a core network of transmission lines along the population-dense southeast coast, much of the Maine system is radial: transmission links between load centers and outlying regions often rely on one or two connecting lines.

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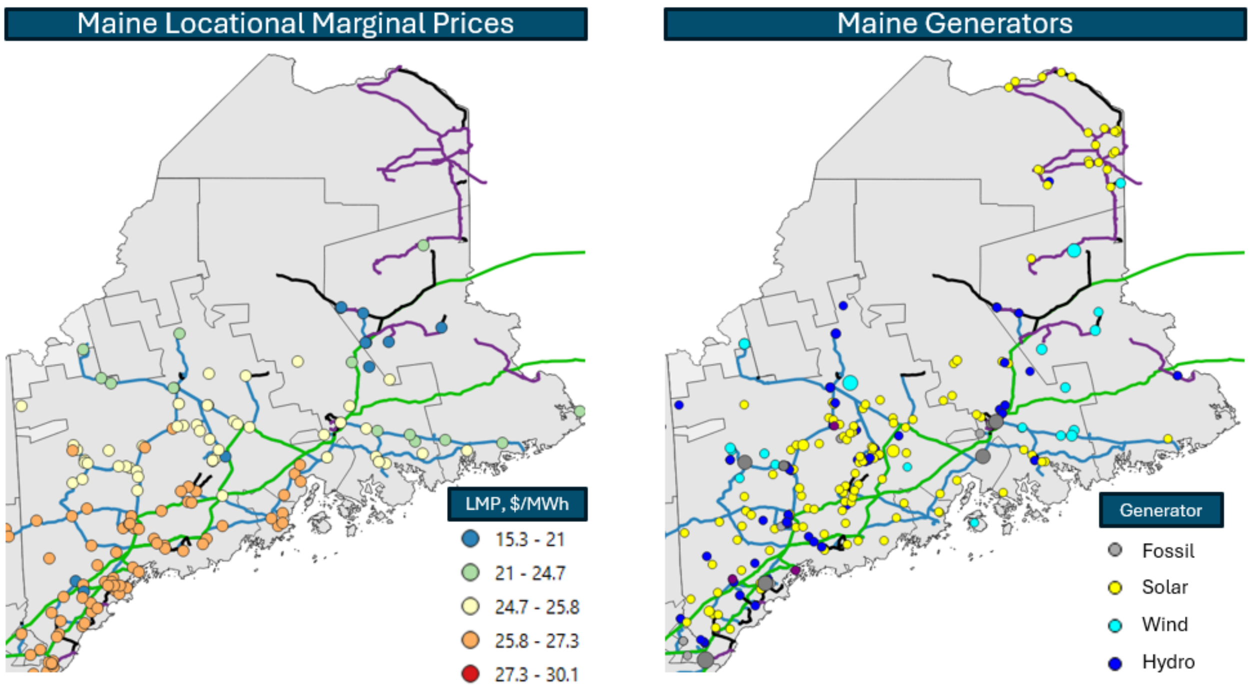
[67] *Note that in doing this, E3 is not suggesting these are the only corridors for DLR deployment, or even the best; rather the selected lines seemed to be potential candidates based on our observations of current generator geographies, price spreads etc.*

[68] ***U.S. Department of Homeland Security***, *Homeland Infrastructure Foundation-Level Data (HIFLD) Transmission Lines Dataset,* [*https://hifld-geoplatform.hub.arcgis.com/datasets/geoplatform::transmission-lines/about*](https://hifld-geoplatform.hub.arcgis.com/datasets/geoplatform::transmission-lines/about)

Existing generators in Maine tend to be geographically clustered by resource type. Solar generators are spread across south-central Maine, with some smaller facilities sited near the northern and eastern borders with New Brunswick, while fossil generators are concentrated near city centers such as Portland and Bangor. Wind and hydropower generators are clustered in the northern and western parts of the state based on resource quality constraints. These resource patterns can be observed in the map shown in Figure 7 below.

Electricity prices on the Maine system have also historically displayed geographic patterns. Prices tend to be high in the population centers in the southwest, which host both a concentration of load and high variable cost generation, and decrease as a function of distance from cities, where rural areas have lower variable cost generation. There are notable low-price pockets in the north and east. Figure 7 shows a series of maps depicting these patterns in 2023.[69] [70]

***Figure 7:** Maine LMPs and Generator Locations*



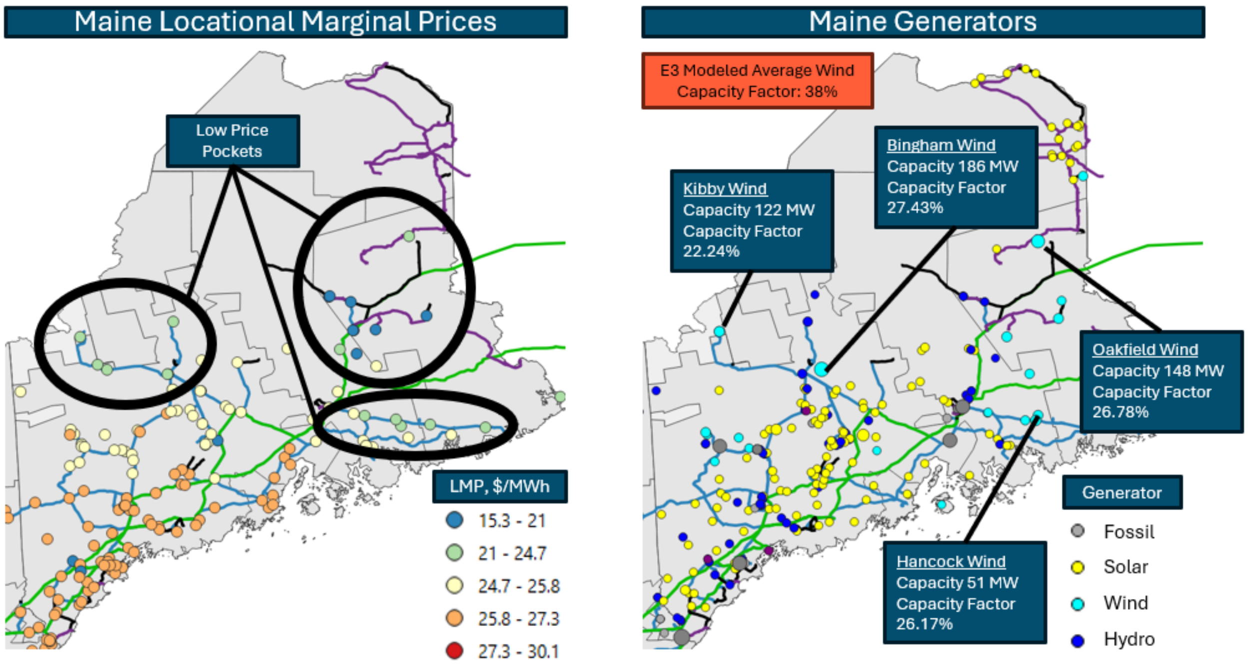

As can be observed in the above maps, many of the pockets of wind generation correspond to lower average wholesale prices. Elsewhere, particularly in the more concentrated load regions in the southern parts of the state, average prices trend as much as $10/MWh higher. This price differential suggests significant congestion on the transmission system between those wind generators and load centers, which is likely to drive curtailment as more wind gets developed in those regions.

[69] ***U.S. Energy Information Administration**, Preliminary Monthly Electric Generator Inventory (Form EIA-860M),* [*https://www.eia.gov/electricity/data/eia860m/*](https://www.eia.gov/electricity/data/eia860m/)

[70] *LMP data was pulled from Velocity Suite, a service of Hitachi Energy: **Hitachi Energy**, Velocity Suite – Market Intelligence Services,* [*https://www.hitachienergy.com/us/en/products-and-solutions/energy-portfolio-management/market-intelligence-services/velocity-suite*](https://www.hitachienergy.com/us/en/products-and-solutions/energy-portfolio-management/market-intelligence-services/velocity-suite)

Generation data from select wind generators in these low-price pockets corroborate this assumption. Wind resource data suggests average capacity factors of ~38% in northern Maine, however realized capacity factors in 2024 for some wind generators were in the mid-20% range, indicating curtailment in many hours throughout the year.[71] This is further illustrated in Figure 8 below.

***Figure 8:*** *Illustration of below average wind CFs for resources in low price pockets*



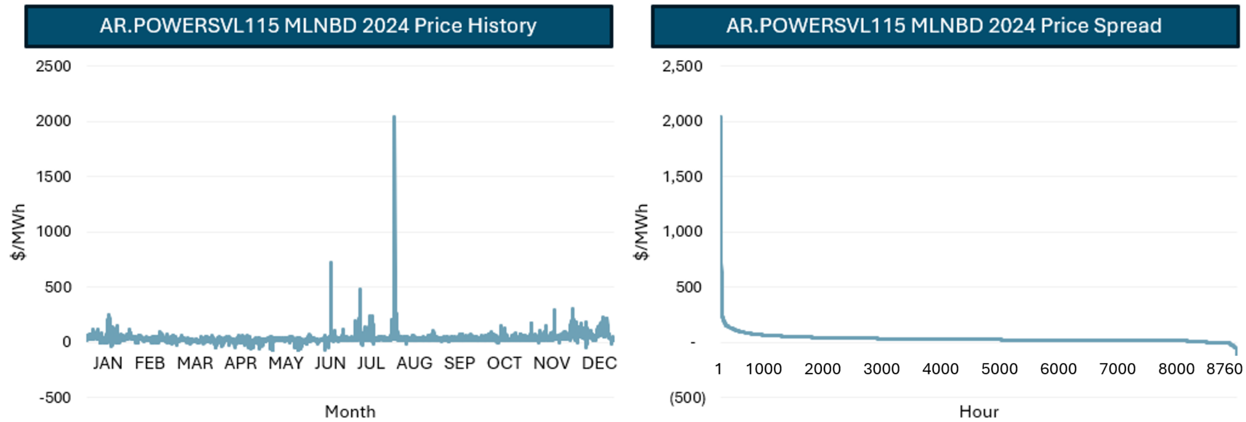

Deployment of DLRs along corridors between these low-price wind pockets and the load centers in the southwest could alleviate this curtailment and yield benefits to ratepayers.

## Estimation of transmission investment benefits

To estimate potential benefits associated with DLR installation, E3 deployed an Avoided Cost methodology to estimate the value of curtailment reductions. To conduct this evaluation, E3 leveraged its in-house ISO-NE market price forecasts, which include projections of load and resource portfolio evolution through 2050, as well as the resulting electricity prices and resource-specific generation volume based on economic dispatch of that system, as modeled at a proxy node representative of a typical wind generation pocket in northeastern Maine. 2024 historical real-time price data and price duration curve demonstrating the level of hourly price volatility are shown in Figure 9 below.

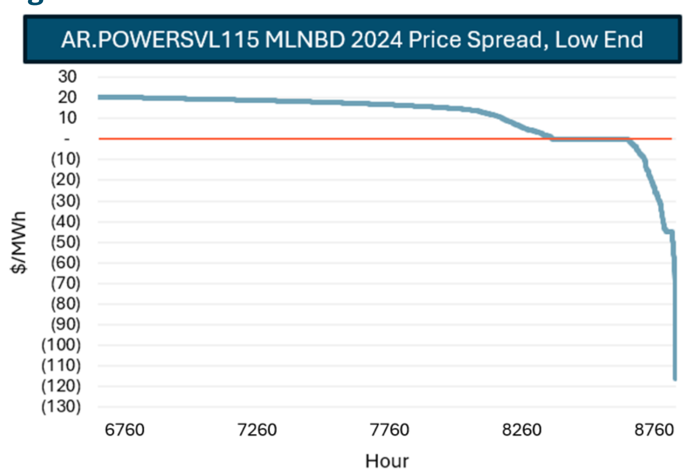
[71] **S&P Global**, *Essential Intelligence*, https://www.spglobal.com/en

***Figure 9:*** *2024 Prices from Select Node*




Most hours of the year see prices between $20/MWh and $40/MWh at this node, though prices decline rapidly below $0/MWh to a low of -$116/MWh. This suggests conditions at the node and connecting transmission line are such that curtailment is likely, leading generators to bid into the market at negative prices. For this analysis, E3 used $0/MWh as the price below which wind curtailment likely occurs; this occurred for 200 hours in 2024. The lowest-priced 2,000 hours are displayed in Figure 10 below to illustrate these pricing patterns. E3's heuristic analysis at this proxy node results in estimated wind curtailment of 0.4% for 2024.[72]

***Figure 10:*** *Price-Hour Duration Curve*




By multiplying this expected wind curtailment by the forecasted zonal marginal price of electricity on an hourly basis, E3 developed an estimated total cost of curtailment to Maine ratepayers. From 2024 to 2050, the total net present value is estimated to be approximately $130 million.[73]

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[72] *E3's analysis includes the following assumptions:*

- *The volume of curtailed energy increases as prices go further negative, with hours featuring slightly negative prices (e.g. -$2/MWh) curtailing a small percentage of available wind capacity, while hours with deeply negative prices (e.g. -$100/MWh) have a greater share of available wind capacity curtailed*
- *The hourly differential between the representative wind node price and the hub price (i.e. the price basis) remains constant from 2024 through 2050, with planned increases in wind deployment keeping pace with load growth, planned transmission upgrades, and storage additions.*

[73] *This value represents the expected total value of curtailment reduction if all congestion causing this economic curtailment were relieved, assuming the value of curtailed energy is equivalent to the zonal marginal price.*

## *Evaluation of Alternative Congestion Alleviation Solutions*

Congestion is traditionally relieved by upgrading or replacing transmission lines to expand their capacity to transmit electricity. This is a time-intensive and expensive process. According to cost data from the ISO-NE 2050 Transmission Study, summarized in Figure 11 below, rebuilding certain economically valuable lines would cost upwards of $6 million per mile at 230 kV.[74] Given recent supply chain constraints and inflation, the per-mile cost of transmission is likely to increase, further increasing the potential benefits of DLR as compared to a traditional upgrade solution.

***Figure 11:*** *Transmission Costs from ISO-NE 2050 Transmission Study*[75]

| Project Type | Assumed Cost |
|---|---|
| **69/115 kV – rebuild of existing overhead lines** | $5M per mile |
| **69/115 kV – new overhead line construction** | $7M per mile |
| **230/345 kV – rebuild of existing overhead lines** | $6M per mile |
| **230/345 kV – new overhead line construction** | $8M per mile |
| **New 115/69 kV transformer** | $10M per transformer |
| **New 345/115 kV transformer** | $10M per transformer |
| **New 69/115 kV circuit breaker** | $2M per breaker |
| **New 230/345 kV circuit breaker** | $2M per breaker |
| **New/replaced underground line construction (any voltage level)** | $35M per mile |

[74] ***ISO New England**, 2050 Transmission Study,* https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf

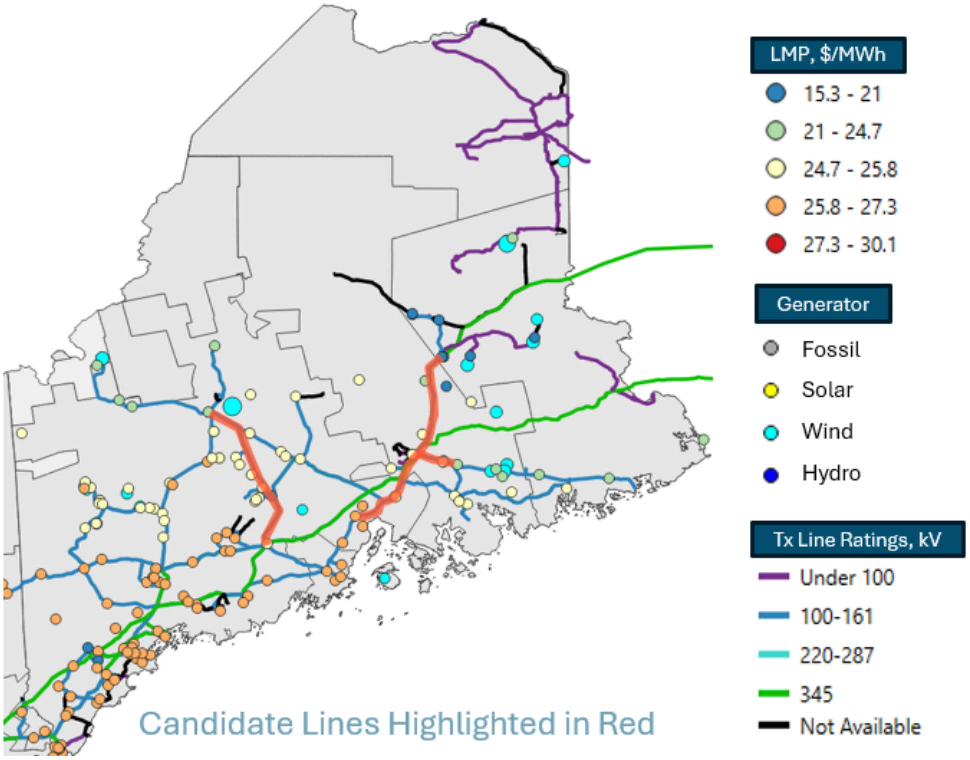
[75] ***ISO New England**, 2050 Transmission Study,* https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf

DLRs, in contrast, carry substantially lower upfront costs. Based on data from the New York DLR simulation study[76], capital costs for DLRs were $8,125 per mile (with total deployment costs of about $1.8 million in $2022). Even with annual fixed costs at about $1,800 per mile (or $250,000 in total) DLRs carry substantially lower costs than conventional solutions. While DLRs carry a shorter lifespan than conventional solutions – with analysis conducted by the U.S. Department of Energy indicating DLRs would have a 12-year asset life before requiring replacement at the original cost – they may still be more cost-effective than alternatives with sufficiently low installation and operating costs.

In examining the Maine system, E3 identified 155 miles of transmission lines as potential candidates for DLR deployment. These lines, all 115 kV, connect the estimated edge of the wind-heavy "congestion pockets" with the nearest high-priced load pocket. Deploying either DLRs or conventional transmission solutions along these corridors has the potential to alleviate observed and future congestion, though as noted elsewhere this should be verified with a nodal production cost analysis prior to any interventions. Selected corridors for this illustrative analysis are illustrated in Figure 12.

*[76] Of the historical examples reviewed for this report, the New York DLR simulation study is the closest parallel to the Maine network and is generally used as a proxy for cost and benefit estimations unless otherwise indicated. This study was selected because it simulated a full section of a transmission grid (as opposed to a single line), the grid section has both radial and network attributes (similar to the Maine grid), the segment contained a mixture of higher and lower voltage lines, including 115 kV lines analogous to the lower voltage lines in Maine, and the deployment scheme of the DLRs was also intended to reduce renewable generation curtailment. In this Department of Energy study, DLR deployments were simulated across 16 transmission line segments, totaling 224 miles of 115 and 230 kV lines, in and around Steuben County, New York.*

***Figure 12:*** *Selected corridors for illustrative analysis*




Across these candidate lines, E3 estimates total upfront DLR deployment costs of approximately \$1.3 million and annual operating costs of \$277,000. This converts to a net present value between 2026 and 2050 of \$5.3 million, using ISO-NE's standard discount rate of 7.5%.[77]

In contrast, a conventional solution would carry a higher initial cost but also provide for larger transfer capacity benefits across its asset life. Rebuilding the 155 miles of 115 kV lines identified above would cost about \$775 million at the ISO-NE assumed cost of \$5 million per mile. Increasing the voltage to 230 kV to enable increased transfer capacity would cost about \$930 million (at a cost of \$6 million per mile). While these costs are significantly higher than those associated with a DLR deployment, they have the possibility of alleviating any expected wind curtailment through 2050.

## Assessment of DLR Impacts on Candidate Maine lines

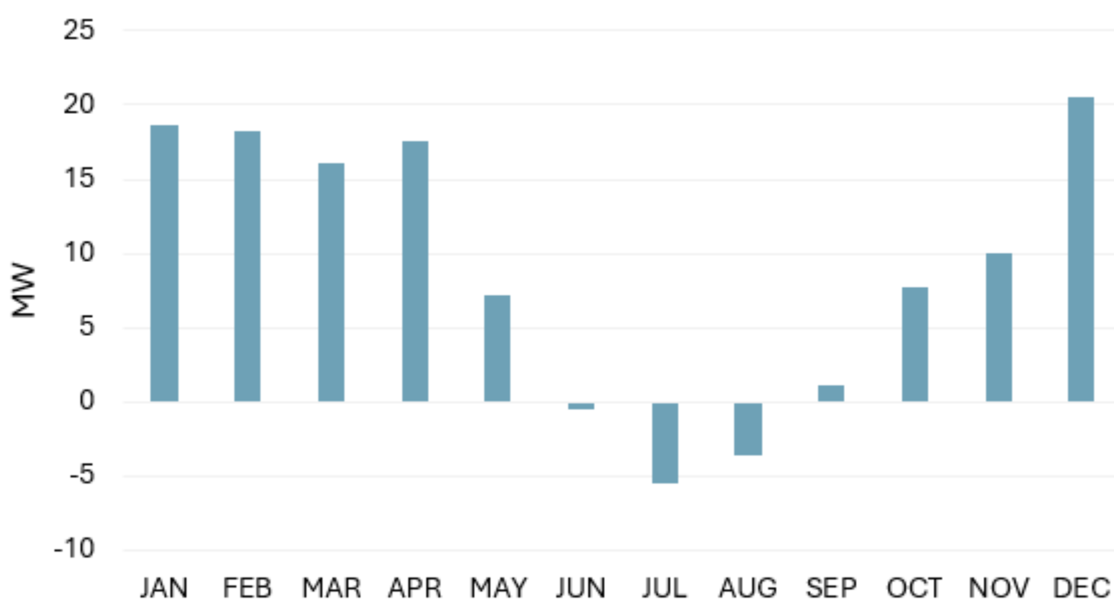
In the New York study, dynamic line ratings yielded a meaningful increase in transfer capacity, although there was significant seasonal variation. That study found that DLRs effected the greatest change in line ratings compared to static line ratings during winter months. However, it also found that optimal line ratings may be lower than static line ratings during the summer months.

[77] **ISO New England**, *Open Access Transmission Tariff (OATT) – Section II,* [https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf](https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf)

**Figure 13:** *Differences between DLRs and Static Line Ratings, Canandaigua to Avoca Line*


Assuming the magnitude of the impact of DLRs is consistent between the New York study and the identified candidate lines in Maine, this analysis estimates that DLRs may increase the capacity of the 115 kV lines in accordance with the schedule below.

**Figure 14:** *DLR Adjustment to Static Line Rating*




This approximation represents the maximum amount of wind curtailment expected to be relieved on any one line as a result of dynamic line ratings. Hourly curtailment volumes above these values may not be relieved since the line's new capacity would still be insufficient to transmit all the generated power. That said, the seasonal pattern in how DLRs affected line ratings in the New York study – with reductions in summer months offset by increases throughout the rest of the year – pair well with Maine's anticipated transmission needs, with both heating load and wind curtailment trending higher during the winter.

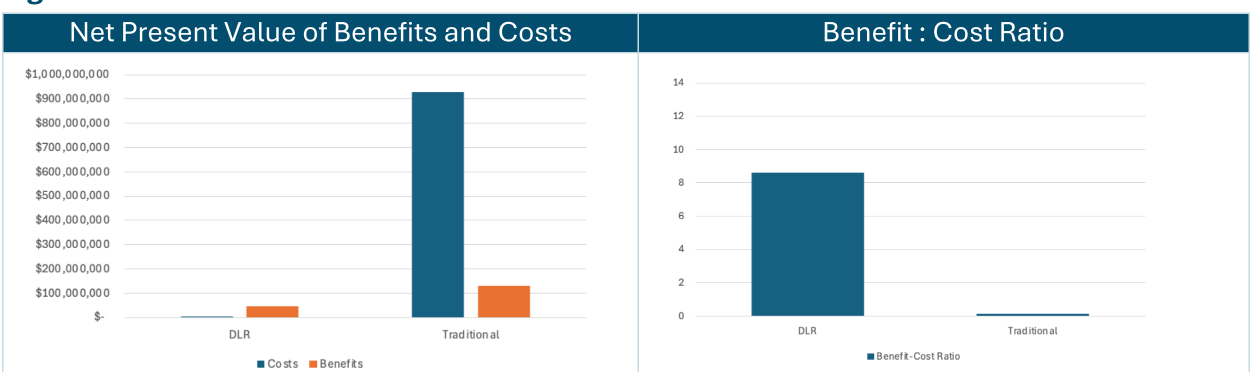
## Benefit-Cost Comparisons

Based on these estimated changes in line rating as well as the seasonal variation in wind curtailment, E3 estimates that in 2026, DLRs could facilitate delivery of about $1.35 million of wind energy that would otherwise be curtailed. This would increase to an annual value of nearly $2.5 million by 2050. The net present value of incremental delivered wind via DLR deployment across the study period would be approximately $45 million. This is about one-third of the total benefits that would be realized from a complete elimination of wind curtailment.

The estimated savings benefits from DLRs decrease in the second half of the study period, despite the absolute volume of reduced curtailment increasing, due to two factors. Firstly, the price of electricity is expected to decrease in real terms over this period, reducing the value of the avoided curtailment, even as the total volume of avoided curtailment increases. Secondly, a large portion of incremental curtailment is expected to take place during hours already experiencing significant curtailment. Since DLRs cannot increase transmission capacity beyond the line's physical transfer limits, additional curtailment over this amount cannot be mitigated.

Comparing the net present value of these benefits and costs illustrates the respective strengths and weaknesses of each approach to curtailment relief.

***Figure 15:*** *NPV of Benefits and Costs*




While traditional transmission upgrades considered in this case would unlock greater total benefits for Maine ratepayers, their benefit-cost ratio is estimated to be 0.14 given the high cost of upgrading the relevant candidate lines. DLRs, meanwhile, return roughly a quarter of the total benefits of a conventional solution, but their lower installation costs result in a benefit-cost ratio of nearly 9:1. This indicates that resources invested into DLRs may deliver significantly higher returns to ratepayers through curtailment reduction than comparable investments in traditional transmission upgrades.

Importantly, this analysis only estimates the value of reduced wind curtailment as a result of these line interventions, though other fixed or operational benefits could be realized as a result of either solution. Fully accounting for other dispatch or investment benefits could change these findings, and might make the benefit-cost ratio of the traditional solution more attractive. These benefits could be quantified (and illustrative findings detailed here could be verified) via a detailed production cost simulation analysis of these line investments in Maine. E3 recommends a follow-on study of this nature in advance of any solicitations or deployments.

### *VPP Deployment for Peak Reduction and Transmission Deferral*

E3's second spreadsheet analysis focused on VPPs for peak reduction and transmission deferral. As Maine's electricity demand grows – particularly during winter peaks driven by heating electrification – the state faces increasing pressure on both its distribution and transmission systems. Traditional infrastructure upgrades can be costly, slow to implement, and often constrained by siting and community opposition. Virtual Power Plants (VPPs) can offer a flexible, scalable alternative, which if deployed strategically could help reduce peak demand, and defer or avoid the need for some expensive transmission system upgrades, particularly in capacity-constrained areas.

## *Peak Driven Transmission Needs in Maine*

As discussed in the "Use-Case Discussion" section above, peak loads in Maine are expected to grow substantially between now and 2050. E3's in-house projections based on heating electrification adoption and other demand drivers suggest that Maine's peak could double by 2035, and triple by 2050. ISO-NE similarly forecasts significant peak growth, along with a switch to a winter-peaking system.[78]

In the "2050 Transmission Study," ISO-NE also created several transmission expansion scenarios to meet this new system peak.[79] The baseline roadmap is designed to both solve local reliability issues and deliver power to the Boston area, and it includes significant new line construction and line rebuilds in Maine.

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[78] ***ISO New England**, 2050 Transmission Study, https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf*

[79] ***ISO New England**, 2050 Transmission Study, https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf*

*__Figure 16:__ ISO-NE 2050 Transmission Study, Baseline Roadmap Build Recommendations*


While ISO-NE does not detail the primary driver of each line rebuild or upgrade, for the purpose of this analysis E3 assumes that rebuilds to the 115 kV system are likely to support local reliability needs in Maine, while new lines and rebuilds of the 345 kV system are more likely to support power delivery to Boston. The total length of the 115 kV rebuild lines in Maine is approximately 153 miles.

## Benefit-Cost Comparisons

Again, leveraging the cost estimates from the ISO-NE 2050 Transmission Study (detailed Figure 11 previously), the cost of rebuilding 153 miles of 115 kV lines is approximately $765 million for the lines alone.

In conjunction with this analysis, E3 reviewed a number of existing VPP programs, and identified the Green Mountain Power Energy Storage System Leasing Program as the most applicable to Maine. This program leased utility-owned and operated in-home batteries to Green Mountain Power customers to mitigate both distribution outages and peak load events. Green Mountain Power retained the ability to control the battery charge / discharge cycle at their discretion. The program enrolled 4,800 customer households for a total aggregate size of 36 MW (7.5 kW / household), or 5% of the utility's system peak. The estimated cost is $5,500 per household.

Assuming the Green Mountain Power model can be scaled, this program would require about 120,000 households, or about 20% of Maine households, to participate to fully mitigate the estimated 2035 Maine peak growth. This same deployment would also mitigate about half of the expected 2050 peak load growth, potentially deferring or eliminating the need for some local transmission upgrades. The estimated net cost for this deployment would be $660 million, 14% lower than the traditional solutions.

This cost may be reduced further if deployments were specifically targeted at locations in most need of transmission upgrades. Additionally, the Green Mountain Power program requires customers pay, in a one-time payment or lease contract, a sum equal to the equipment costs of the battery. Implementing a similar requirement would further lower costs to Maine utilities; fully shifting costs onto program participants may yield up to 12.5% return on investments over a 10-year span.[80]

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[80] ***State of Vermont Public Utility Commission,*** *Final Order Approving Tariff Revisions,* [*https://s3.documentcloud.org/documents/23930878/135809408571174onbase-unity_4129703845439947985406349.pdf*](https://s3.documentcloud.org/documents/23930878/135809408571174onbase-unity_4129703845439947985406349.pdf)

It is worth noting that the GMP model is just one of many potential approaches that a VPP can take. Other programs, designed to aggregate existing customer resources rather than encourage new adoption, may demonstrate both lower costs and more limited benefits, which may result in a more favorable overall benefit/cost ratio depending on the nature of the program.

## Use Case Summary

The use cases presented in this section demonstrate the significant potential of GETs to help address Maine's evolving transmission challenges. By leveraging technologies such as Dynamic Line Ratings (DLRs) and Virtual Power Plants (VPPs), Maine may be able to defer some high-cost line upgrades without slowing the pace of renewable integration or risking outages despite growing peak demands. The illustrative DLR case study highlights how real-time thermal ratings may be able to unlock additional capacity for wind integration, reducing curtailment and deferring costly upgrades. Similarly, the VPP case study examines the potential for aggregated DERs to provide targeted peak load relief and support local reliability. Together, these examples underscore how these technologies could become cost-effective, near-term solutions that align with Maine's clean energy goals and mitigate infrastructure constraints. They will not be appropriate in all cases, nor will they defer other upgrades indefinitely; however, they should be evaluated alongside conventional solutions and may yield benefits for Maine's ratepayers in the years to come.

# Section 5. Conclusion

Maine's electric system could benefit from new investment in T&D infrastructure, driven by a combination of  electrification-driven load growth, a policy-driven transition towards renewables in the generation sector, high customer costs, and a desire to improve resilience in the face of extreme weather events. Given the high upfront cost of deploying conventional solutions, alternative approaches such as GETs and VPPs have the potential to alleviate some of these challenges on a more cost-efficient basis.

In particular, DLRs show promise as an approach to mitigate curtailment and increase deliverability along constrained transmission corridors as the share of wind generation in Maine's electricity mix expands.  Before deploying DLRs on a particular line, further research should be conducted to determine production cost savings on a nodal level under different load-growth and generation buildout scenarios. Furthermore, VPPs may have the potential to reduce peak demand and improve system reliability, but should also be evaluated at the nodal level and in comparison with more conventional grid-hardening solutions at both transmission and distribution  scale. In contrast, PFC and TO solutions are unlikely to yield material benefits for Maine ratepayers in the absence of further transmission network buildout to increase redundancy, as the number of viable alternative power flow routes in Maine's radial network is relatively low.

In the near term, further evaluation of DLRs and VPPs, including the deployment of small-scale pilot initiatives, can help the MPUC further refine the use cases for and value proposition of these technologies in helping Maine meet its RPS requirements and/or enhance system reliability in a cost-effective manner. Table 4 below summarizes both the key takeaways for DLR and VPP deployment in Maine and suggested next steps for the Maine PUC to consider, in collaboration with key stakeholders,  to further study and progress the deployment of GETs in Maine.

***Table 4:** Suggested Next Steps to Further Deployment of High-Potential GETs*

| | Key Takeaways for Maine | Suggested Next Steps for MPUC |
|---|---|---|
| **DLR** | DLR is a strong candidate for deployment in Maine on specific transmission lines with high wind generation curtailment<br><br>Investing in the foundational IT infrastructure is critical for the grid to be able to interpret and react to the signals from DLR sensors | Should the MPUC wish to further explore DLR it could investigate the costs, benefits and technical feasibility of DLR in Maine in more detail, including stakeholder input<br><br>Work with utilities on nodal production cost studies of any potential candidate lines to better understand the value of DLR<br><br>Identify whether existing tariffs support recovery of DLR-related costs or whether modifications are needed to explicitly authorize cost recovery |

| | | |
|---|---|---|
| | | Work with utilities to understand operating procedures and the training requirements for system operators to be able to interpret and act on DLR data<br><br>Work with ISO-NE to develop a roadmap of how DLR data can be integrated into their operational models<br><br>Work with ISO-NE to understand the requirements for telemetry, data formats and integration timelines<br><br>Engage with ISO-NE, NEPOOL, and other New England stakeholders to establish regional planning processes that can accommodate DLR as a non-wires alternative |
| **VPP** | VPPs are a strong candidate to optimize the distribution system in Maine<br><br>Realizing the value of VPPs will require a regulatory change in how the market values those resources and utility investments in the software necessary to manage them | Should the MPUC wish to further investigate the potential use of VPPs in Maine it could explore defining VPPs and assessing value, in particular to clarify what resources constitute a VPP, what their minimum size should be and what control requirements are necessary<br><br>Consider if any tariff or rate design changes would be needed to retail rates, interconnection rules and cost recovery mechanisms to support VPP participation and utility compensation<br><br>Work with utilities to understand software needs to be able to integrate VPP signals into their operational protocols<br><br>Consider conducting a VPP pilot program in coordination with Maine utilities<br><br>Coordinate with ISO-NE on market participation of VPPs as they work on their FERC Order 2222 implementation and compliance |

# Appendix A: Funding and Investment Mechanisms for Transmission in Maine

T&D investments in Maine are funded through a variety of mechanisms that depend on the scope and objective of the expenditure. Distribution-level programs, demand response, and energy efficiency initiatives have been mostly implemented from dedicated state and federal grants, incentives, and direct funding. However, despite substantial funding for these distribution-level resources, financing options specifically targeting transmission infrastructure beyond the typical ISO-NE framework described in Section 3 have been comparatively limited.

This section of the report discusses the recent and planned investments and existing mechanisms for Maine's transmission system. It first recounts recent and planned investments in Maine's transmission infrastructure including describing the most significant project upgrades. It then describes the public funding initiatives in Maine that go towards distribution and demand response investments such as the Efficiency Maine Trust (EMT) and the Flexible Interconnection and Resilience for Maine (FIRM).

## Recent and Planned Investments in Maine's Transmission Infrastructure

As mentioned in Section 3, Maine's electric grid has required significant upgrades and new transmission projects in the past decade. One major driver for these transmission upgrades was that much of Maine's transmission infrastructure was built over 40 years ago, raising reliability concerns due to ageing equipment with increased failure rates.[81] Another major driver is the integration of renewable energy resources – particularly large wind projects in northern Maine and hydroelectric imports from Canada – which necessitate new high-voltage lines to deliver power to consumers. The aforementioned Integrated Grid Plan legislation was enacted to address these concerns and coordinate system planning efforts across the state.

Some of **the most significant transmission projects that have started development or construction over the last decade include:**

- New England Clean Energy Connect (NECEC): The NECEC is a 145-mile 320kV HVDC line which mostly follows existing utility corridors and has a transmission capacity of 1.2 GW. The purpose of this line is to deliver clean hydropower from Quebec to Maine and the rest of New England. The project was first proposed in 2017 and has faced significant legal challenges and delays following the approval of a ballot Initiative in 2021 (Maine Question 1). However,

[81] ***Central Maine Power**, Maine Power Reliability Program Reaches New Milestones,* [https://www.cmpco.com/w/cmps-maine-power-reliability-program-reaches-new-milestones](https://www.cmpco.com/w/cmps-maine-power-reliability-program-reaches-new-milestones)

this ballot initiative was struck down in courts and the line is expected to be completed in 2026.[82,83]

- Aroostook Wind & Transmission: In 2021 Maine enacted legislation directing the Public Utilities Commission (PUC) to facilitate a competitive procurement process for transmission projects that can interconnect the wind-rich and currently isolated region of Aroostook County in northern Maine to the rest of New England.[84] In October 2022, the MPUC awarded the contracts to LS Power for the proposed roughly 150-mile 345kV transmission line that would connect Glenwood, ME to a new substation in Coopers Mills, ME. The contract stipulated that Massachusetts would buy 40% of the power from this project while also helping pay for it proportionally. This contract however was terminated in 2023 due to local opposition and an unexpected increase in material costs. The MPUC is now preparing a new solicitation that is expected to be completed in 2025.[85,86] This project was bolstered in October 2024 when project developer Avangrid - CMP's parent company - was awarded a $425M federal capacity contract through the U.S. Department of Energy's Grid Deployment Office under the Transmission Facilitation Program (TFP), created by the 2021 Infrastructure Investment and Jobs Act.[87]
- Maine Power Reliability Program (MPRP): The MPRP was a comprehensive build-out of 440 miles of new transmission lines and five new substations reinforcing the region's transmission backbone from Maine's southern border up through central Maine. Planning for the MPRP began in the mid-2000s, based on ISO-NE's identification of Maine's reliability needs.[88] The project was completed in 2015 and has significantly contributed to Maine's transmission reliability metrics outlined by NERC and ISO-NE under the latter's Planning Procedure No. 3 (PP3).[89] It remains one of the largest transmission investment projects in Maine's history, costing approximately $1.4 billion.[90]

In addition to these large transmission projects, Maine has been investing in broader grid modernization and upgrade initiatives, including substation modernization efforts such as the

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82 ***New England Clean Energy Connect***, *Project Overview*, *https://www.necleanenergyconnect.org/*
83 ***Climate Case Chart***, *NECEC Transmission LLC v. Bureau of Parks and Lands, Maine Department of Agriculture, Conservation and Forestry*, *https://climatecasechart.com/case/necec-transmission-llc-v-bureau-of-parks-lands-maine-department-of-agriculture-conservation-and-forestry/*
84 ***Maine Legislature***, *SP0563 Bill Text*, *https://mainelegislature.org/legis/bills/getPDF.asp?paper=SP0563&item=5&snum=130*
85 ***Maine Public Utilities Commission***, *Document Reference ID: 1047928C-0000-C915-85C1-DE73B07A9304*, *https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7b1047928C-0000-C915-85C1-DE73B07A9304%7d&DocExt=pdf&DocName=%7b1047928C-0000-C915-85C1-DE73B07A9304%7d.pdf*
86 ***Maine Public Utilities Commission***, *Northern Maine RFP Awarded Contracts*, *https://www.maine.gov/mpuc/regulated-utilities/electricity/rfp-awarded-contracts/northernmainerfp*
87 ***Avangrid***, *Avangrid Awarded $425M Federal Capacity Contract for Maine Transmission Project*, *https://www.avangrid.com/w/avangrid-awarded-425m-federal-capacity-contract-for-maine-transmission-project*
88 ***ISO New England***, *Section 254 Cost Update*, *https://www.iso-ne.com/static-assets/documents/2018/03/section_254_cost_update.pdf*
89 ***ISO New England***, *Planning Procedure 3, Revision 8 (PP3 R8)*, *https://www.iso-ne.com/static-assets/documents/2017/10/pp3_r8.pdf*
90 ***Central Maine Power***, *Maine Power Reliability Program Reaches New Milestones*, *https://www.cmpco.com/w/cmps-maine-power-reliability-program-reaches-new-milestones*

Westbrook upgrade[91] and the Scarborough substation enhancement[92], as well as the deployment of smart controls like CMP's Advanced Metering Infrastructure project, which included the installation of smart meters and communication systems. [93]

## The Efficiency Maine Trust

The Efficiency Maine Trust (EMT) is an independent state-affiliated agency that runs programs to promote energy efficiency, load shifting, beneficial electrification, and greenhouse gas reductions across the state. The Trust was created by a revision to Maine Revised Statutes (MRS) 35-A, Chapter 97 in 2009 and is governed by an independent Board of Trustees with oversight from the Maine Public Utilities Commission [94]

The EMT operates under a three-year strategic plan (the Triennial Plan)[95] which covers programs in residential, commercial, and industrial sectors ranging from weatherization and efficient appliances to rebates for clean grid technologies such as:

- Battery Storage Incentives
- Demand Response and Load Shifting
- Electric Vehicle to Grid infrastructure and program development
- Non-Wire Alternatives (NWA) (added as an amendment in 2019 under L.D. 1181)
- Grid-Enhancing Technologies (added via subsequent legislation in 2024 under L.D. 589)

These technological solutions can serve as alternatives to otherwise expanding the grid and were incorporated into the process for planning and approving T&D system improvements by the Maine Legislature in recent years, allowing planners to consider them in place of traditional transmission or distribution projects (such as a substation upgrade or new line) when they are more cost-effective.

The EMT is funded by specific revenue streams. These revenue streams include:

- Payments made directly by the utilities to achieve the "Maximum Achievable Cost-Effective" (MACE) energy savings from energy efficiency and beneficial electrification resources, based on assessments of cost-effectiveness, reliability, and achievability. The EMT first conducts studies to identify energy-saving opportunities, followed by a cost-benefit analysis to evaluate the economic merits of the proposed program relative to its implementation cost. If the program is deemed beneficial by the relevant agencies and stakeholders, the utilities

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[91] **Central Maine Power**, *Modernizing Westbrook Substation*, https://www.cmpco.com/w/cmp-modernizing-westbrook-substation
[92] **Central Maine Power**, *Central Maine Power Improves Power Reliability in Scarborough*, https://www.cmpco.com/w/central-maine-power-improves-power-reliability-in-scarborough
[93] **U.S. Department of Energy**, *Central Maine Project Description*, https://www.energy.gov/sites/default/files/2017/08/f35/Central_Maine_Project_Description.pdf
[94] **Maine Legislature**, *Title 35-A, Chapter 97: Energy Infrastructure Development*, https://legislature.maine.gov/legis/statutes/35-A/title35-Ach97.pdf
[95] **Efficiency Maine Trust**, *Triennial Plan VI*, https://www.efficiencymaine.com/triennial-plan-vi/

are directed to collect the necessary funds, which are then transferred to the EMT to enact the programs.[96,97]

- The Regional Greenhouse Gas Initiative (RGGI), a multi-state cap-and-invest program intended to reduce greenhouse gas emissions from the power sector by implementing a regional emissions cap which allows for the sale of “carbon allowances” auctions. Disbursements from RGGI are remitted directly to the Trust.[98]
- The ISO-NE Forward Capacity Market (FCM) mechanism through which the operator ensures that sufficient resources are available to meet future electricity demand. The EMT participates in the FCM by aggregating the capacity savings from its energy efficiency programs and bidding them into the market. The EMT is then compensated for these bids, which can be used for reinvestment.[99]
- Federal funds such available through the Infrastructure and Investment Jobs Act (IIJA), the Inflation Reduction Act (IRA), and ARPA initiatives.[100]
- Legal settlements such as the Volkswagen emissions settlement, the NECEC settlement, and the MPRP settlement. [101]

## Flexible Interconnection and Resilience for Maine (FIRM)

Launched in October 2024, the stated goal of the FIRM project is to “deploy cutting-edge software and hardware to enhance grid stability, regulate voltage, and increase transmission capacity on existing lines”[102] to enhance Maine’s electric grid by deploying advanced technologies.

The FIRM project is a collaborative effort that involves a public-private partnership between the Governor’s Energy Office (GEO) and the investor-owned utilities Central Maine Power (CMP) and Versant Power. The project is funded by a $65 million grant from the U.S. Department of Energy’s Grid Deployment Office (GDO) under the Grid Resilience and Innovation Partnerships (GRIP) program which is funded through the Bipartisan Infrastructure Law (BIL).

Maine’s GEO and PUC structured FIRM to address challenges identified in planning discussions such as rural grid constraints and renewable interconnections. In CMP’s service territory specifically, this funding will be used to deploy Active Network Management (ANM) and Dynamic Line Rating (DLR) technologies.[103]

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[96] ***Maine Legislature***, *Title 35-A, Chapter 97: Energy Infrastructure Development,* *https://legislature.maine.gov/legis/statutes/35-A/title35-Ach97.pdf*

[97] ***Efficiency Maine Trust***, *Chapter 3 Electric Rule Proposed Amendments (11.20.2023),* *https://www.efficiencymaine.com/docs/EMT_Ch3_Electric-Rule_Proposed-Amendments_11.20.2023.pdf*

[98] ***Regional Greenhouse Gas Initiative***, *Official Website,* *https://www.rggi.org/*

[99] ***Efficiency Maine Trust***, *FY2024 Annual Report,* *https://www.efficiencymaine.com/docs/FY2024-Annual-Report.pdf*

[100] ***Efficiency Maine Trust***, *Federal Funding Opportunities,* *https://www.efficiencymaine.com/federal-funding*

[101] ***American Council for an Energy-Efficient Economy***, *State and Local Policy Database – Maine,* *https://database.aceee.org/state/maine*

[102] ***Maine Governor's Energy Office***, *Firm Grant Announcement – October 2024,* *https://www.maine.gov/energy/press-releases-firm-grant-announcement-oct-2024*

[103] ***Avangrid***, *Avangrid Subsidiary Awarded $31.8M Federal Grant to Deploy Cutting-Edge Grid Technology,* *https://www.avangrid.com/w/avangrid-subsidiary-awarded-31-8m-federal-grant-to-deploy-cutting-edge-grid-technology*