U.S. DEPARTMENT OF ENERGY

Grid-Enhancing Technologies:

A Case Study on Ratepayer Impact

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Executive Summary

A modern grid requires modern infrastructure, including new devices enabled by digital technology or simply new paths for electricity to flow. Grid-enhancing technologies (GETs) maximize the transmission of electricity across the existing system through a family of technologies that include sensors, power flow control devices, and analytical tools. This report establishes an assessment methodology and outlines key findings with respect to an identified case study region on how GETs can be applied today to save ratepayers money while the grid transitions to a cleaner generation mix.

The Federal Energy Regulatory Commission (FERC) has been actively working to establish the appropriate incentive mechanisms for technology adoption. This report focuses on the evaluation of the impacts of GETs on wholesale and retail power rates. A case study is presented on regional, wide-spread deployment of GETs to assess the potential benefits and costs to utilities and ratepayers.

This report establishes the techno-economic framework for the benefits quantification of GETs on the wholesale power market. The outcomes from this report show that GETs can be cost-effective in the target region, ultimately saving ratepayers money while integrating more renewable generation. However, the impact of GETs is highly location-specific, and this location was selected because of its high likelihood for increased renewable generation and GETs suitability. Additional studies should be completed to assess GETs impact in other regions of interest.

The results of this study suggest that GETs could prove cost-effective across the country in avoiding renewable generation curtailment in the short-term and remain useful to facilitate the interconnection of future generation resources, while also providing situational awareness and flexibility in the long-term.

Background

To fully understand the results of the case study, a short overview of both the power system and GETs is provided. The electric power system must balance electrical supply and demand in real-time because electricity travels rapidly and misalignment can lead to a broad spectrum of consequences ranging from unsuitable frequency and voltage at the customer-level to cascading outages and load shedding across the network. To ensure the alignment of supply and demand, generation has historically been adjusted and dispatched to meet the needs of consumers and the economy.

In an ideal world, the most affordable generation would be dispatched first, and increasingly more expensive generation would be ramped up to meet customer demand. Unfortunately, generation merit order based solely on economics is unrealistic because of physical constraints on the system. The generation portfolio is thus usually sub-optimally dispatched, often constrained by non-economic factors including lacking the transmission and distribution infrastructure required to move electricity from generators to load centers. When the transmission system limits generation dispatch economics, this is known as “congestion.” Transmission congestion is defined by the U.S. Department of Energy (DOE) as the economic impact on the users of electricity that results from physical transmission constraints that limit the amount of power flow to ensure safe and reliable operation [3]. For example, the flow of power may be restricted by the maximum thermal limit of a transformer or power line conductor. Therefore, operators are forced to reroute power through less optimal paths and rely on more expensive power generation, like conventional fossil fuels, while curtailing renewable wind or solar to safely meet the demand of their customers. The end result is that congestion causes customers to pay more money for the energy they use. According to a 2018 DOE report, the sum of real-time congestion cost for 2016 among major system operators—specifically, the California Independent System Operator (CAISO), the Electricity Reliability Council of Texas (ERCOT), Independent System Operator New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), and PJM—was $4.8 billion [4]. In comparison, value of electricity retail sales in the U.S. totaled $387 billion in 2016 [5].

There are a variety of methods that can be used to address congestion. Thinking of the transmission system like a transportation system (roads) often helps new audiences. Traditional upgrades for the transmission system include upgrading existing equipment with higher capacity alternatives. In the transportation system, more capacity involves adding a new lane to an existing highway. Another traditional upgrade is to simply build new lines or roads to provide alternate routes for power/traffic flow; however, permitting and construction for these methods can be costly and time consuming. GETs can usually be deployed more quickly than those traditional alternatives. The term GETs encompasses new technology used to enhance the existing grid infrastructure, and include energy storage, customer-side management, and coordinated electric vehicle charging. This report discusses optimization software and dynamic transformer rating (DTR) in depth, but focuses on the following:

- **Dynamic Line Rating (DLR) –** Hardware and/or software used to appropriately update the calculated thermal limits of existing transmission lines based on real-time and forecasted weather conditions. Often, these schemes establish new limits that safely allow more energy transfer across existing infrastructure.
- **Power Flow Controllers (PFC) –** Hardware and software used to push or pull power, helping to balance overloaded lines and underutilized corridors within the transmission network.

Extending the transportation analogy to GETs is relatively straightforward. PFCs provide some traffic control for the transmission system. These effectively allow for more optimal use of the existing infrastructure, similar to how reversible center lanes allow for traffic to flow in different directions depending on the time of day.[1] Dynamic Line Ratings can be thought of in terms of variable speed limit highways. Rather than a fixed maximum speed at which traffic is allowed to travel on a given highway, DLR might allow traffic to travel at much higher rates of speed when it is appropriate to do so given a vehicle's proper roadworthiness (well-equipped supercar and professional driver versus an original wood-spoked single engine classic with a driver who only has a learner's permit) and the environmental conditions (sunshine, no rain or snow or ice in the forecast). The opposite may be true as well: DLR provides situational awareness for when the road conditions change due to poor weather moving in or reduced speed limits due to road construction, resulting in line ratings that are operationally less than static or ambient adjusted ratings. While the ratings are operationally less than static, the additional situational awareness yields system reliability and visibility benefits.

This report outlines a methodology for quantifying the benefits of GETs by employing a techno-economic power grid planning study using a technique known as production modeling. The study evaluates grid operations with respect to generation dispatch optimization under a variety of scenarios with and without the implementation of PFC and DLR technologies across each hour of the year. The primary objective of the study was to develop a techno-economic framework for evaluating GETs generally through a case study of one region in the State of New York with high renewable energy potential. As a result, the methodology can be used as a template for future analyses by grid operators, transmission owners, and technology vendors. Specifically, the objectives of this case study were five-fold:

- Develop a screening methodology to identify candidate regions and transmission lines best suited for the deployment of GETs.
- Identify candidate technologies and better understand their capability, technical specifications, and necessary inputs for grid modeling.
- Establish a methodology to site GETs for maximum value.
- Create a process to model the utilization of GETs with respect to grid operations that isolates and quantifies the impacts of GETs on a variety of factors.
- Develop a methodology for calculating system benefits and ratepayer impact.

Case Study Highlights

There is ample opportunity for GETs to support existing grid infrastructure and alleviate existing transmission constraints, as well as future constraints from expected shifts in power supply and demand. The case study presented here evaluates a near-future scenario (2025) with increased renewable adoption in an area of the State of New York to better understand how GETs could integrate more generation on the existing transmission infrastructure.

The New York Independent System Operator (NYISO) service area was selected as the regional case study for this analysis because it has existing wind curtailments despite low overall

[1] Throughout the report, there are references to n-degrees of PFC. The power systems calculations used to model commercially available solutions are found in Appendix C. However, these varying degrees can be thought of as incrementally adding more reversible center lanes. Rather than converting one lane of an 8-lane highway to bi-directional traffic, this report effectively analyzed the impact on converting multiple lanes.

penetration, high congestion costs, and large proposals for new transmission and wind and solar resources. To integrate the large amounts of wind and solar resources needed to achieve the state's 70% renewable energy goal by 2030, significant transmission investment is required, however the use of GETs and other enabling technology can help facilitate this transition by making better use of existing transmission lines and potentially defering or augmenting costly traditional transmission upgrades.

To assess the impact of GETs, the case study evaluated multiple generation scenarios and technology strategies:

Scenarios:

- The **Base Case**, which evaluated the level of renewables currently built in NYISO, but layered atop the 2025 transmission topology.
- The **Interconnection Queue** scenario, which added approximately 3 gigawatts (GW) of additional solar capacity and 4 GW of additional wind capacity from the NYISO Interconnection Queue to the system, for a total buildout of roughly 8 GW of solar and 6 GW of wind.
- The **70% by 2030** scenario, which was created to model the approximate amount of renewable generation that would be needed to achieve the State of New York's goal of 70% renewable generation by 2030.

Strategies:

- The **Base Case**, which establishes a baseline performance based on 2025.
- **Traditional Upgrades**, which include reconductoring most of the region and building a new substation.
- **GETs Cases**, which provide combinations of DLR (rather than static line rating [SLR]), and PFCs at varying points in the region (6 cases total).
- **GETs + Traditional**, which leverages a combination of PFCs, DLRs, and traditional upgrades in an effort to maximize the benefits of both traditional and GETs strategies.

Line loading is used to understand the flows along the transmission system and verify the cost savings attribution of more efficient generation dispatch. Table 1 outlines the various cost savings metrics associated with each of the technology strategies. The ability for DLR and PFC technologies to be used together and achieve nearly the sum of their parts highlights their complementary nature. Instead of having overlapping gains, the results of this case study show that each technology provides unique value to the system: for example, all PFCs evaluated showed a significant (23 – 43%) reduction in curtailment, and some line segments' utilization more than doubled with PFCs versus the Interconnection Queue case. As discussed in Section 2.2, note that these savings metrics all reflect more efficient dispatch and should not be added together for a total system impact metric.

Table 1. Summary of annual savings across production cost, net imports, and avoided curtailment across all scenarios.

	Production Cost Savings (k$)*	Net Imports Savings (k$)*	Avoided Curtailment Savings (k$)**
Interconnection Queue	N/A	N/A	N/A
With 2-degree PFCs	1,704	1,260	4,221
With 4-degree PFCs	2,854	1,085	6,189
With 8-degree PFCs	4,586	1,851	8,103
With DLRs	113	2,273	1,717
With 4-degree PFCs & DLRs	3,214	2,639	7,814
With Traditional Upgrades	2,479	4,374	13,597
With GETs and New Substation	4,008	978	9,115

*Relative to Interconnection Queue Scenario.
**Savings from Avoided Curtailment using $43/MWh LCOE, Relative to the Interconnection Queue Scenario.

Wholesale cost-savings are just one metric. Understanding the net impact to the ratepayer helps solidify the scale of cost savings and the potential for GETs. As covered extensively in Section 2.2, the evaluation of GETs is challenging on both the benefit and cost sides. With respect to costs, investment decisions in advanced transmission technologies need to consider total lifecycle costs, including capital and operations and maintenance (O&M), integration, and business process improvements. When examining benefits, even limiting the benefit calculations of GETs to market impacts can yield multiple metrics, which cannot necessarily be summed. Additionally, GETs also provide benefits that are more difficult to quantify, such as the value of asset deferral, improved asset health monitoring, better situational awareness, improvements in public safety, and increased resilience. Due to their nature as dynamic resources, the evaluation of GETs is a multivariate endeavor that reflects the complex nature of transmission planning.

Translating the above wholesale cost savings to ratepayers is an indirect exercise. Adding to the complexity, consistent details on GETs costs are unavailable in the public sphere. Even if detailed cost for GETs were readily available, details typically held internal to utilities would need to be identified for a detailed ratepayer impact assessment. Moreover, policy guidance is needed on appropriate benefits allocation, given the breadth of impact of GETs across the market when deployed in small regions.

This report outlines a variety of methods to consider benefits of GETs. Generally, the results of this case study suggest that GETs could prove cost-beneficial in avoiding renewable generation curtailment in the short-term and remain useful to facilitate the interconnection of future generation resources while also providing situational awareness and flexibility resources in the longer term. To be clear, the GETs strategies did not integrate as much renewable generation as traditional solutions, but they also cost less and may be faster to implement. Another key takeaway from the case study is that finding the *perfect* location for GETs is unnecessary; each scenario that was studied proved promising and worthy of additional inquiry.

Finally, to obtain a detailed assessment of the impact to ratepayers, Figure 1 outlines the cost estimates for the various technology strategies considered relative to the annual value of energy curtailment avoided. Note that relative to the Traditional Upgrades, the GETs strategies are generally significantly less costly and inch toward the high benefit established by traditional upgrades.

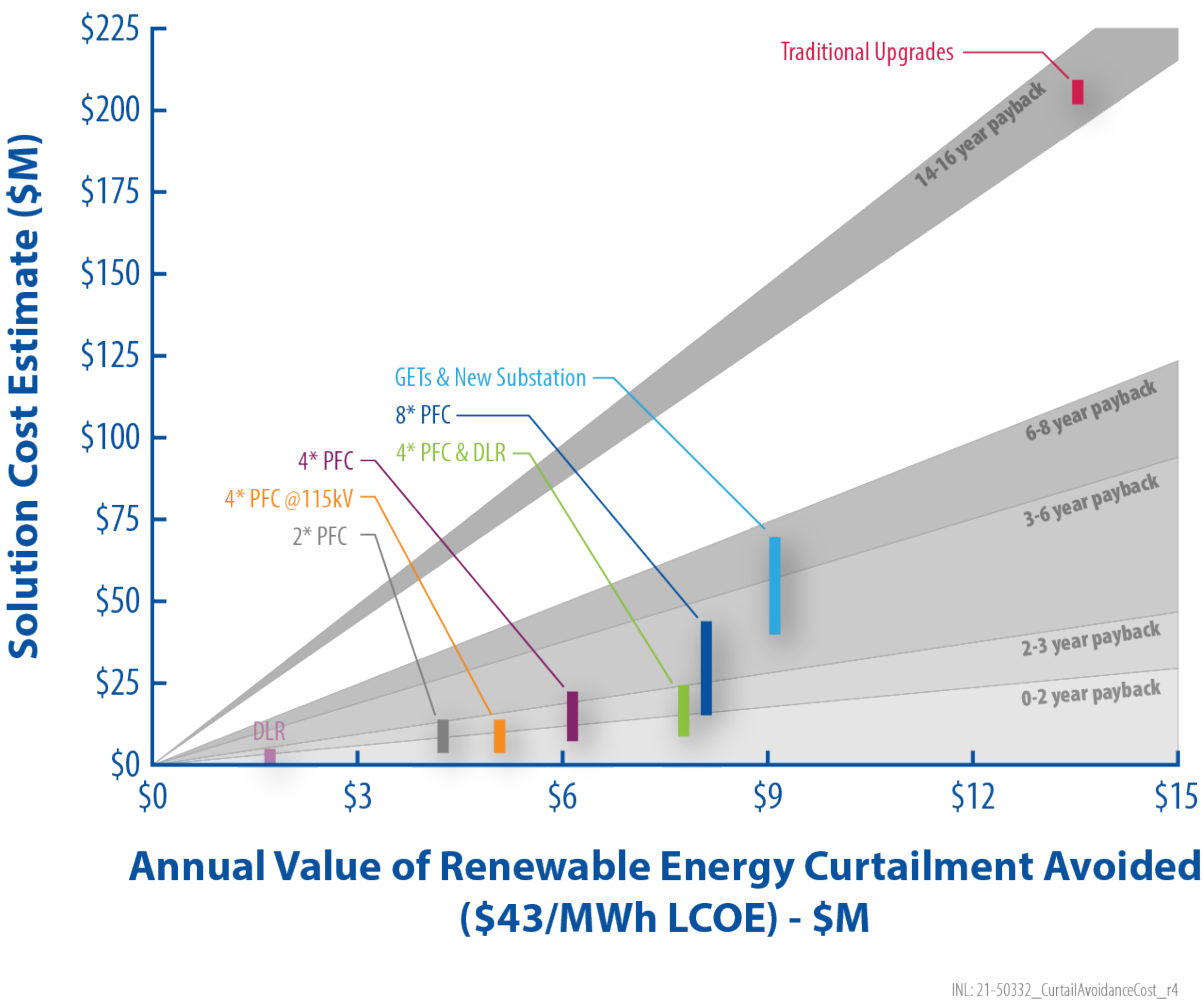
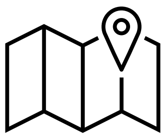


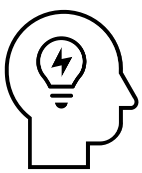
Figure 1. Solution cost estimates relative to the annual value of the renewable energy curtailment avoided.

Recommendations

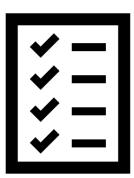
The following are some of the recommendations and takeaways from the results of this study. More context for the basis of these recommendations is available throughout the report and in Section 3.4, which is dedicated to recommendations.



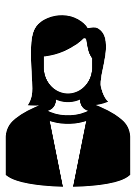
Selecting Locations: The impact of DLRs and PFCs is highly location-dependent and should be assessed on a per case basis.



GETs Should be Considered: GETs should be evaluated as a candidate technology in resource and transmission planning and directly compared against traditional technologies. Commercial solutions exist and should be considered for full scale implementation as optimization and refinements continue.



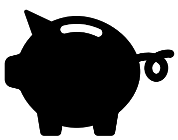
Assemble a Task Force to Share GETs Data: Electric utilities are traditionally risk averse organizations. The gaps in public knowledge with respect to GETs leads utilities to established, known solutions. A task force should be charged with providing industry with the data needed for fair GETs consideration to ameliorate perceived risk of the modern technologies.



Workforce Development: Many modern grid technologies seem to be stuck in a cycle of “pilots” where the technology is considered in isolation, rather than as part of the new “business-as-normal.” Shifting organizational thinking is possible by requiring enhanced training for planning engineers & grid operators such that they are trained and versed in new approaches when faced with the implementation of innovation.

Further Research is Needed to Accelerate Adoption: The case study outlined herein and those found in other recent works advance the methodologies and public knowledge surrounding GETs, but additional research could further modernize bulk-power system planning and operations by:

- Expanding the scope of GETs studied here (PFCs and DLR) to include transformers, energy storage, and dispatchable demand side resources.
- Identifying the optimal solution set of GETs alongside traditional upgrades.
- Providing a toolkit for incorporating transmission capacity forecasting into generation dispatch decision-making.



Benefits / Cost Allocation / Incentives: The incentives to build GETs are often misaligned from those who benefit most. There are many interested stakeholders whose primary focus is *not* on the efficient economic planning and operation of the power system. Mechanisms are needed to ensure GETs are implemented and utilized for the benefit of ratepayers as appropriate.

Acronyms

AAR	Ambient Adjusted Ratings
AC	Alternating Current
ADR	Ampacimon Dynamic Rating
ANSI	American National Standards Institute
ATC	Available Transfer Capability
BESS	Battery Energy Storage Systems
CAISO	California Independent System Operator
CARIS	Congestion Assessment and Resource Integration Study
CEII	Critical Energy/Electric Infrastructure Information
CFD	Computational Fluid Dynamics
CIGRE	Council on Large Electric Systems
CIP	Critical Infrastructure Protection
CLCPA	Climate Leadership and Community Protection Act
DC	Direct Current
DCOPF	DC Optimal Power Flow
D-FACTS	Distributed Flexible Alternating Current Transmission Systems
DLR	Dynamic Line Rating
DOE	U.S. Department of Energy
dPV	Distributed Photovoltaic
DSPx	(Next Generation) Distribution System Planning
DSR	Distributed Series Reactors
DSSC	Distributed Static Series Compensator
DTR	Dynamic Transformer Rating
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FACTS	Flexible Alternating Current Transmission Systems
FERC	Federal Energy Regulatory Commission
GET	Grid-Enhancing Technology
GW	Gigawatt
GWh	Gigawatt Hour
HIFLD	Homeland Infrastructure Foundation-Level Data
HTLS	High-Temperature Low-Sag
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operators
kV	Kilovolt
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized or Lifecycle Cost of Energy

LMP	Locational Marginal Price
LPT	Large Power Transformer
MMWG	Multiregional Modeling Working Group
MVA	Megavolt-Amperes
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
OHL	Overhead Line
OTLM	Overhead Transmission Line Monitoring
PAR	Phase Angle Regulator
PFC	Power Flow Controller
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PTC	Production Tax Credit
PV	Photovoltaic
RES	Renewable Energy Standard
RTO	Regional Transmission Operator
SLR	Static Line Rating
SPP	Southwest Power Pool
SSSC	Static Synchronous Series Compensator
TARA	Transmission Adequacy and Reliability Assessment
TO	Transmission Operator
U.S.	United States
UPFC	Unified Power Flow Controller
uPV	Utility-Scale Photovoltaic

GRID-ENHANCING TECHNOLOGIES:
A Case Study on Ratepayer Impact

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1 Introduction

1.1 State of the United States Electric Grid

The United States (U.S.) electric power grid is a complex system divided into three main sections or "interconnections" that consist of more than 7,300 power plants, nearly 160,000 miles of high-voltage transmission lines, and millions of low-voltage power lines and transformers [6], [7]. While this electrical system has enabled extraordinary benefits to everyday quality of life, it has also increased society's vulnerability when reliability is disrupted. The recent power outages due to the 2020 California wildfires [6] and the 2021 Texas winter storm [7] highlight the modern dependence on reliable electric power. Without changes, similar disruptions are expected to continue as climate change is projected to strengthen weather events [8].

In response to climate change, efforts are being expended to reduce human environmental impacts by supplying electricity from clean energy sources. However, shifting the generation mix is impeded by the Nation's transmission infrastructure, most of which was designed to transmit energy from large fossil fuel generators to load centers. One measure of this outdated infrastructure is known as congestion, which often results in the curtailment of renewable energies to avoid damage to the system.[b] In 2018, a combined 723.2 gigawatt hours (GWh) of solar energy was curtailed in California, Texas, Arizona, and Hawaii, accounting for 2.2% of potential solar generation in these states [9]. As the demand for electric power continues to increase, so will the expectations on the infrastructure that facilitates its delivery, ultimately leading to more curtailment of solar and wind energies unless the current infrastructure is modified to support a grid heavily reliant upon clean energy.

[b] "Curtailment" is a reduction in the output of a generator from what it could otherwise produce given available resources, typically on an involuntary basis. Generation curtailment has been a normal occurrence since the beginning of the electric power industry, but is regaining focus for wind and solar generation due to the zero marginal cost of their fuel.

In addition to facilitating climate impacts, infrastructure modernization, whether through grid-enhancing technology or more traditional system upgrades, is an urgent need as many of the grid's assets are aging and due for replacement in the coming decade. Modernizing this infrastructure will help to ensure continued safe and reliable grid operations in a clean energy-focused future. Moreover, the grid of the future will stress the existing system, but the transition to that future will require a grid with new capabilities, potentially leveraging intelligent features of grid-enhancing technologies (GETs) to prevent transmission corridors from being overloaded. As shown in the case study in this report, these technologies face many hurdles to achieve widespread deployment, but have the potential to save people money while integrating more renewable generation.

1.2 Transmission Congestion

The goal of the electric grid is to safely deliver reliable power to customers at an affordable cost. Transmission congestion is defined by the U.S. Department of Energy (DOE) as the economic impact on the users of electricity resulting from physical transmission constraints that limit the amount of power flow to ensure safe and reliable operation [3]. For example, the flow of power may be limited by the maximum thermal constraint of a transformer or a transmission conductor. Therefore, operators are forced to reroute power through less optimal paths and rely on more expensive power generation, like conventional fossil fuels, while curtailing renewable wind or solar in order to safely meet the demand of their customers. This may increase reliance on high-emissions fossil fuels, delaying the clean energy transition, as well as cost customers more money and extend the time required to recoup the cost of generation investment. Extreme cases of transmission constraints may push the entire system beyond its operational limits, forcing utilities to employ periodic load shedding tactics (i.e., rolling backouts). These cases are highly problematic in that blackouts can endanger public health and result in large financial losses for the economy. The three main causes for transmission congestion are voltage limits, system stability limits, and thermal limits.

1.2.1 Voltage Limits

The power grid has various voltage classes that are measured in kilovolts (kV) (e.g., 500 kV, 230 kV, 138 kV, 46 kV, 13.8 kV, etc.) throughout the system. Different standards inform acceptable tolerances around these levels. These standards also specify an acceptable magnitude and duration of voltage that may exceed these tolerances. Voltages below these tolerances, or undervoltage, can be caused due to insufficient power generation to support loads. The low voltage results from loads attempting to draw more current than the generators can produce. To compensate, the generator allows the voltage to drop so that additional current may be fed into the system. Various loads, such as air conditioners, motors, and manufacturing plants cannot function if the voltage drops too low. Undervoltage issues are primarily due to a lack of generation reserve to support loads as opposed to congestion concerns. Conversely, a voltage above a specified tolerance is known as overvoltage. This may be caused by complicated effects of dispatch patterns, generation settings, and transients, such as lightning strikes or short circuits, or when too much power is injected into the system during peak solar generation and low energy demand. Overvoltage has the potential to damage both equipment on the power system and loads on the system. Overvoltage may contribute to congestion issues if specific areas of the grid are operating at upper voltage limits, which may require operators to rebalance power flow in a less cost-effective manner.

Insufficient reactive power support is also a potential cause of congestion issues. Capacitive and inductive elements within the power grid consume reactive power, whereas resistive elements consume “real power.” If power needs to be rerouted due to thermal congestion, the different—and usually longer—path will have greater reactive power demand. If the generator is at its maximum power operating condition, it may not be able to support the additional reactive power demand on the new route, causing the unit to eventually trip offline. Typically, power-factor (i.e., phase angle) correction devices, which are a type of grid-enhancing technology, attempt to alleviate reactive power demands from the system.

1.2.2 Stability Limits

The U.S. bulk-power grid uses alternating current (AC) operating at 60 Hz. Standards such as the Institute of Electrical and Electronics Engineers (IEEE) C37.016 and ANSI C84.1 specify acceptable frequency deviation tolerances during nominal operations. Frequency deviations can occur in two forms: over/under frequency where the operating frequency deviates from 60 Hz, and phase deviations where 60 Hz voltage and current waves are not oscillating in sync. Over- and under-frequency deviations follow similar patterns to overvoltage and undervoltage issues resulting from a mismatch between power production and load demand. Phase deviations may result from sudden changes in the load, faults on the power line, or insufficient reactive power support. If the phase difference between the voltage and current deviates significantly, the generator may become damaged, trip offline, and/or require other generators to make up for its lack of production. This sudden demand for energy generation can cause further phase deviation with other generators on the system, which, if significant enough, can cause a chain reaction of other generators tripping offline. Faults on the power line may also cause phase deviation because they force the generator to suddenly ramp up energy generation; however, fault protection devices usually guard against this.

1.2.3 Thermal Limits

As electricity passes over and through the infrastructure that makes up the transmission system, that infrastructure is heated. Infrastructure components can operate at a range of temperatures, and there are limits and risks associated with exceeding their thermal limits. The thermal limits of a power line conductor are based on either the maximum or emergency operating temperature of the conductor or to avoid distance-to-ground clearance violations. These thermal limits are one of the leading causes of transmission congestion and are directly related to the line itself, rather than as some function of the broader system. Therefore, system operators have a direct interest in safely increasing the power capacity of transmission lines.

The maximum current carrying capacity of a conductor is termed ampacity. Industry standards for ampacity calculations have been published by IEEE in standard 738 [10] and in technical brochures 207 [11] and 601 [12] by the Council on Large Electric Systems (CIGRE). The ampacity equations are based on the thermal energy balance of a conductor, wind and radiative cooling, and heating from the sun and joule effects as shown in Figure 2. These standards provide the methods for determining the ampacity using methods, such as Static Line Rating (SLR), seasonally adjusted ratings, Ambient Adjusted Rating (AAR), or Dynamic Line Rating (DLR).

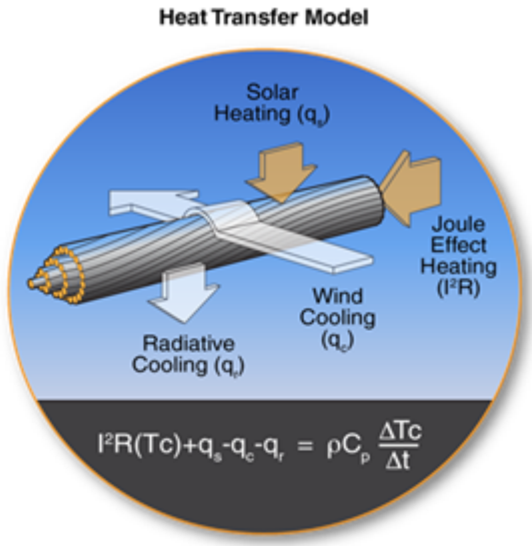


Figure 2. Representation of heat transfer on a conductor.

The heat transfer model is an important reminder that these conductors are a physical material with properties impacted by heating. In turn, high temperatures cause transmission lines to sag more. In addition, regularly overheating the conductor will slowly deteriorate the conductor, shortening its useful life. More extreme overheating of the conductor may lead to annealing, compromising the integrity of the material.

As the conductor is heated, the material sags toward the ground. This can lead to safety concerns, line outages, and stability concerns. In addition, conductors too close to the ground or next to vegetation can cause sparks that under the right conditions can lead to wildfires. In addition to ensuring safe conductor temperatures, thermal limits consider the distance of the conductor to the ground as a limiting factor.

1.3 Grid-Enhancing Technologies Overview

A formal definition of "GETs" has not been established by DOE and requires further analysis and discovery as innovation evolves in this space. Regardless, this report briefly covers many of the currently recognized GETs technologies to ensure the reader is well prepared to understand the outcome of the case study presented. Additional discussion on GETs in general can be found in Appendix A.

GETs can help increase the transfer capability of transmission systems across real-time and operational planning horizons. This report focuses on: Dynamic Line Ratings and Advanced

Power Flow Control, while also discussing Topology Optimization and Dynamic Transformer Ratings. However, there are many types of GETs, including energy storage facilities, which can be used as grid assets to employ during times of need [13]. For example, the Nantucket Island supply in the State of Massachusetts directs stored energy to the Island during the summer peak, augmenting transmission capacity to the mainland [14]. Other demand-side resources, such as demand response, can also be used as a form of GET. Another type of GET is a High-Temperature Low-Sag (HTLS) conductor, which increases the ampacity of a transmission line by using materials in the conductor that increase heat emissivity and reduce thermal expansion (i.e., sag in the line). Though utilities have been employing this technology [15], it has several tradeoffs, such as lower line loadability and steady-state stability limits.

1.3.1 Dynamic Line Ratings

Traditionally, transmission operators (TOs) have used the SLR method, which assumes constant environmental variables in the heat balance equation [16].[c] More broadly, TOs use seasonal ratings, where those static environmental assumptions are adjusted depending on the time of year. Recently, some TOs have adopted AARs, which adjust line ratings based on ambient air temperature, but do not account for wind or solar effects.[d]

Across the U.S., various methods are employed [2]. Many Transmission Operators, Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) choose to utilize different values for the weather variables to calculate SLR ampacity. For instance, they may use historical local weather data in their region to get a better estimate of the weather variables and improve the estimate for the ampacity of a conductor in their area. Some choose to use seasonal SLRs to take advantage of lower ambient temperatures in the spring, fall, and winter. Yet another potential approach is to allow for a higher conductor temperature. All these strategies inch toward DLR.

In recent years, attention on research and use-cases for DLR methodology has increased. DLR uses near-term weather conditions in the heat balance equation to give a more accurate representation of the true ampacity of the conductor. Oftentimes, using the actual weather information or observed conductor behavior results in higher line rating ampacity than what is assumed in SLR. Consequently, power flow can be unnecessarily limited when using SLRs since conductors are not actually at their thermal limits.

To attain better situational awareness of transmission conductors and safely increase their ampacity, the adoption of DLR methodologies is gaining traction. Today, there are many technologies and methodologies for determining the near-term ampacity of overhead

[c] Southwire, one of the world's leading manufacturers of wire and cable, gives guidance on the ampacity rating of conductors using SLR. Southwire calculates the ampacity rating of conductor by using the following assumptions: a maximum allowable conductor temperature of 75°C, ambient temperature of 25°C, wind velocity of 2 ft/s perpendicular to the conductor, heat emissivity of 0.5, and full sun. These environmental conditions are assumed to be conservative, and thus, maintain a safe operation of the transmission conductor.

[d] Note that some RTOs do consider AARs that adjust by day and night due to solar effects, but do not adjust ratings throughout the day based on real-time weather conditions.

conductors. In principle, DLR is based on the same heat-balance equations as an SLR but improves upon static ratings by utilizing near-term environmental conditions [17].

DLR adjusts thermal ratings based on actual field conditions. DLR approaches account for ambient weather conditions and real-time monitoring of line behavior. DLR technologies fall into two main categories: direct and indirect. Direct methods use sensors that may be directly connected to the conductor, connected to towers, or on the ground. The sensors measure variables such as line temperature, tension, or sag to rate the ampacity of the line. Indirect methods infer the ampacity using technologies, such as forecasted wind velocity and direction along the length of the lines.

DLR can provide insight into the performance of a line over time. Rather than relying on engineering assumptions and maintenance schedules, the real-time status of the line can be used in decision-making to decrease component failures and reduce congestion without degrading reliability.

The increased operational flexibility offered with DLRs is beneficial during certain extreme weather conditions, such as when extremely low temperatures and wind chill cause high electricity demand, equipment failures, and fuel supply constraints that result in generators being taken out of service. DLRs would provide grid operators the option and ability to take advantage of the fact that colder temperatures and high winds allow for increased capacity on transmission lines. In general, using DLRs can support more electricity delivery options during a disruption, thereby mitigating demand interruptions. It can also facilitate recovery and restoration after an event.

1.3.2 Dynamic Transformer Ratings

As previously mentioned, GETs have the potential to unlock more capacity on existing infrastructure. However, that extra capacity is only useful insofar as it can be carried throughout the electric power system from generation to the end-user. For example, extra capacity on one transmission line span is only useful if the next span can also accommodate it. This idea is applicable throughout the power system, including within the substations that facilitate power transfer. To use an analogy, DLR has the potential to expand the Nation's power highway system, but the exits and intersections must be capable of using that new capability for it to be worthwhile. At the nexus of these power system exits and intersections are transformers, which are often the biggest and most expensive component(s) of a substation.

Transformers shift power between voltages, helping to facilitate "step-up" and "step-down" transitions throughout the power system. They have long been recognized as vital for the resilience of the U.S. electric sector [18] [19]. Because of the power system's reliance on transformers, ensuring the health of these assets is important. Therefore, utilities set and maintain standards for their performance and loading. Design standards vary across the country, but generally follow guidance from IEEE working group 57 and the IEEE/American National Standards Institute (ANSI) C57.91 standard [20]. Although transformers can occasionally be operated safely at modest levels above the nameplate rating from the manufacturer, this practice has the potential to accelerate the aging effects on the transformers, potentially driving the power system to a more fragile state if these impacts are not adequately addressed [17].

In addition to operational contingency concerns for a failing transformer, these assets are expensive to replace and can take months to purchase and deliver. In 2014, DOE defined large power transformers (LPTs) as those with a maximum nameplate (i.e., nominal) rating of 100 megavolt-amperes (MVA) or higher. LPTs can cost millions of dollars and weigh between 100 and 400 tons (or between 200,000 and 800,000 pounds) [19]. Regarding the lead-time on an LPT, a 2014 DOE report stated: “In 2010, the average lead-time between a customer’s LPT order and the date of delivery ranged from five to 12 months for domestic producers and six to 16 months for producers outside the U.S. The LPT market is characterized as a cyclical market with a correlation between volume, lead-time, and price. In other words, the average lead-time can increase when the demand is high, up to 18 to 24 months.” [19]

Reports generalizing the limiting element of a given transmission corridor are not readily available. A 1996 report on the New York power system [21] outlined that the conductor itself served as the thermally limiting element about 42% of the time. The same report outlined that transformers served as the limiting element nearly 10% of the time while other substation equipment, such as current transformers (used in metering) and circuit breakers, contributed to the rest of the thermal limits. PJM Interconnection (PJM) noted that the substation often proved to be the limiting element in a DLR study in 2018 [22].

Similar to DLR for power lines, dynamic transformer ratings attempt to use additional transformer capacity to prevent congestion while still limiting potentially detrimental thermal impacts on asset health.

1.3.3 Power Flow Control & Topology Optimization

In bulk electric system operations, the laws of physics state that electricity flows based on network impedance. Power flow in AC systems is unlike other flow problems, such as flow in transportation and telecommunications. In a transportation system, trucks can be routed along a desired path from a source to a destination. Similarly, in a communications system, packets can be routed such that they travel along the quickest path between a sender and a receiver. However, electricity must follow paths according to physics, resulting in an inability to route and directly control power flow. Power flow control is also different from other types of flow problems since electricity must also be produced when needed and there is currently limited storage on the system. In other systems for distributing goods, products can be stored in a warehouse until they need to be sent to the end-user. If the desired supply is unavailable, the end-user can wait, and it will arrive later. In power systems, customers are in control of how much power they use and always expect that amount of power to be available.

The power flow control problem is further complicated by the highly interconnected structure of transmission networks typical in North America. To ensure the reliability of the power system, there are many smaller sub-systems working together to provide multiple paths, guaranteeing that customers continue to receive power if any one thing fails. If some step does fail, there are controls in place to isolate faulted areas quickly, limiting service interruption to customers. However, a utility cannot effectively control how much power flows through its network due to the interconnections with other systems. When a transfer between two areas occurs, it impacts the flows on other lines in the system, potentially even on lines which are far away. These unintended flows due to interconnections can restrict transmission capability since the available transfer capability (ATC) of an interface is limited by the first facility to reach its limits. Even a single overload can prevent many transfers from being able to take place [2].

Power Flow Controllers (PFCs) are a set of technologies that reroute power away from overloaded lines and onto underutilized corridors within the existing transmission network. Several power flow control solutions exist, such as series reactors, phase shifting transformers, Static Series Synchronous Compensators (SSSC), and Unified Power Flow Controllers (UPFC). Some power flow control devices work by adjusting impedance of the lines, thereby enabling utilities to effectively push power away from an overloaded line or pull power onto an underutilized line.

Transmission topology optimization is a software technology that identifies reconfigurations in the grid to route power flow around congested or overloaded transmission elements, taking advantage of the meshed nature of the bulk-power grid. The reconfigurations are implemented by switching high voltage circuit breakers. By more evenly distributing flow over the network, topology optimization increases the transfer capacity of the grid.

Topology optimization can be used when responding to contingencies to help eliminate overloads and violations, minimizing outages, and increasing reliability. The software can quickly identify optimal corrective actions given the altered operating state. The technology can also be used to improve outage scheduling and coordination. This enables optimized system states for these contingency situations to avoid reliability violations and minimize congestion.

1.3.4 Adoption Challenges of GETs

For a variety of reasons, the deployment of GETs in the U.S. has been slow. Some are outlined below. The recommendations presented in Section 3 will help to overcome these challenges.

Technology Challenges

The technological capabilities of GETs have been proven in various pilot studies; the case study presented in Section 2 outlines millions of dollars in potential savings. Utilities and system operators are conservative entities that require new technology systems and components to be tested, evaluated, and proven to ensure reliable operation of the system. Continued investments in transparent programs can simulate realistic end-use cases and environments and allow for third-party evaluations of those programs.

The successful implementation of GETs requires the ability to communicate between the field-deployed equipment, such as sensors and control devices, and the control rooms or other decision systems in a timely manner. This combination of field equipment and software increases complexity of the installed systems by requiring communications to coordinate functions, among other issues. Many different technologies can be used as communication channels, including radio, cellular networks, satellite, fiber optics, and physical media. However, the choice of technology will depend on the monitoring approach, as well as the requirements of the application, especially with respect to data-transfer capacity and latency levels. For example, simple weather stations only need to transmit a few environmental parameters to the control center on a regular basis. For these small data packet applications, many existing technologies can be used, and the choice becomes dependent on cost, terrain, and network availability. As the number of capabilities and measured parameters increase for sensing and monitoring technologies, the communications requirement to manage the availability, latency, and integrity of larger data sets also increases.

Cybersecurity is an important aspect of implementing any grid-enhancing system. In the recent past, there have been many credible reports that point to cyber-intrusion in our energy sector from adversaries abroad. The fact that adversaries have infiltrated U.S. energy systems and can easily cause disruptions to the electric supply highlights the importance of strong cybersecurity. A recent example occurred on May 7, 2021, where Colonial Pipeline, a Houston, Texas-based company that carries gasoline and jet fuel mainly to the Southeastern U.S., suffered a ransomware cyberattack that impacted computerized equipment managing the pipeline [23]. Actions like these can result in unintended equipment outages on the bulk-power system and loss of reliable energy supplies to customers. Field sensing devices, communication links, third-party hosting services, controllers, power electronics, and other elements of a new system are all potential threat vectors available to malicious actors.

Industry Challenges

Many segments of the utility industry lack the incentive to promote and integrate new, unproven technologies in the system. This incentive problem ranges from executive-level decision-making down to engineering objective functions. With respect to the executive-level, transmission owners and utilities receive a rate of return on their capital investments for infrastructure projects. GETs often represent lower capital cost alternatives to traditional investments such as new transmission lines, meaning a lower overall return for investors. With respect to engineering objectives, system planners are required to meet transmission reliability planning standards, and the performance of new technologies under worst case scenarios may be unknown. Certain GETs, such as DLRs, principally improve economic efficiency rather than providing a planning basis for worst case scenarios.

Adopting advanced transmission technologies into utility operations will require the integration of technological systems, as well as human processes. Some of these technologies require new equipment in the control room, increased human intervention, and additional training. Trust in the performance of the new technologies is also critical for operator comfort. Utilities and system operators need to be familiar with the operation of these new technologies to eliminate unintended consequences.

Evaluation Challenges

The case study presented herein outlines a framework for the evaluation of GETs, but the temporal nature of GETs value requires a full, chronological, 8760 hour per year framework, in addition to traditional steady-state assessments that evaluate individual system snapshots in time. This shift toward temporal grid planning will need to be carried through each step of the generation, transmission, and distribution planning processes. A variety of economic and power systems planning tools and considerations are used in the procurement and implementation of modern grid equipment. Updating each of those tools to a temporal framework that appropriately captures the economic and physical system value of GETs could present a barrier to implementation.

1.4 Goals and Objectives of the Report

This report highlights methods that improve the utilization of the existing electricity delivery system by enabling DLR, dynamically controlling the flow of electricity, and optimizing electricity delivery system topology. Addressing the challenges of the growing complexity of the modern grid requires better utilization of sensors, development of power flow control devices and analytical tools, and novel control mechanisms that would allow maximized transmission of electricity and improvement of grid resilience. These are all features provided by GETs; however, many obstacles must be overcome to fully adopt and integrate GETs.

Adoption obstacles for GETs include market readiness, proper evaluation, insufficient incentives, perceived risk associated with dynamic operation, cybersecurity, and technology validation. This report focuses on the evaluation of the impacts of GETs technology on wholesale and retail power rates. A case study is presented on regional, wide-spread deployment of DLR technologies to assess the potential benefits and costs to utilities and ratepayers.

This report also addresses the need to develop strategies that incorporate existing tools and to have a better understanding of the benefit of GETs tools. An overview of GETs including DLR, PFCs, and other technologies is provided and published case studies that demonstrate the cost and benefits of GETs are presented. To obtain a detailed assessment of the impact to ratepayers, this report also implements a methodology that can be used as a part of a comprehensive approach to quantify the cost and benefits of GETs using production modeling data and software.

Finally, this report outlines a methodology for quantifying the benefits of GETs by employing a techno-economic power grid planning study. The study was conducted to evaluate grid operations and renewable deployment with and without the implementation of PFC and DLR technologies. A key objective of this report is to develop a general evaluation framework that may be used as a template for future analyses by grid operators, transmission owners, and technology vendors for evaluating GETs.

2 Grid-Enhancing Technology Case Study

2.1 Methodology and Results

2.1.1 Case Study Introduction

Across the industry, the increase in wind and solar generation is changing the way power flows across the power network. Utility-scale projects are generally located in rural areas and can be far from large metropolitan areas and load centers. The transmission network transfers power from the source of generation to the end-use customers. As a result, the integration of wind and solar technology often requires additional transmission buildout.

Lack of transmission infrastructure creates challenges for further renewable integration, including transmission congestion, price separation across the network (e.g., high prices paid by loads and low prices received by renewable generators), and renewable curtailment.

While wind, solar, and battery technologies can be developed quickly (e.g., 1–2 years), new transmission has a much longer lead-time requirement—typically requiring several years to plan, permit, and construct. Regardless of the timing challenge, new transmission projects are notoriously difficult to site.

As a result, there is a growing need to utilize the existing transmission network more efficiently, aside from any addition of new lines. New technologies are available to increase the flexibility of the transmission network. These include sensor and modeling technologies that allow for DLRs of transmission lines based on ambient conditions, PFCs that adjust line impedances to reroute power away from congested elements, and software that can identify when changes to network topology can lead to more efficient power flows across the grid.

These emerging technologies can increase flexibility in the transmission network and provide significant value to both ratepayers and generation owners by reducing transmission congestion, limiting renewable curtailment, and accelerating the renewable development with less need for new transmission.

To quantify the costs and benefits of GETs, a techno-economic power grid planning study was conducted to evaluate grid operations and renewable deployment, with and without PFC and DLR technologies implemented. While this section provides a case study in one region of the State of New York with high renewable energy potential, the objective of the study was to develop a techno-economic framework for evaluating GETs more generally. As a result, the methodology can be used as a template for future analyses by grid operators, transmission owners, and technology vendors. Specifically, the objectives of this case study were five-fold:

- Develop a screening methodology to identify candidate regions and transmission lines best suited for GETs deployment
- Identify candidate technologies and better understand their capability, technical specifications, and necessary inputs for grid modeling
- Establish a methodology to site GETs technologies for maximum value
- Create a process to model GETs utilization and changes to grid operations and to isolate and quantify the impacts of GETs on reduced transmission congestion, decreased curtailment, environmental benefits, and generation cost savings
- Develop a methodology for calculating system benefits and ratepayer savings.

While there is ample opportunity for GETs to support existing grid infrastructure and alleviate existing transmission constraints, this study focused on a future scenario with increased renewable adoption. The reason for this was to evaluate GETs as an enabler of new renewable deployment and as a tool to accelerate new generation interconnection and defer traditional transmission upgrades. GETs can also be viewed as an intermediate step while renewable generation is deployed, but before larger system upgrades can be put into place.

To accomplish the goals of the study, a future scenario was evaluated that assumed the entire wind and solar Interconnection Queue for a New York Independent System Operator (NYISO) was deployed. While full deployment of specific projects in the interconnection queue is highly unlikely, this information was used as a proxy for the type and location of new resources being proposed and necessary to meet the state's clean energy goals. As Section 2.1.4 illustrates, this represents a near doubling of New York's current wind and solar capacity. This would increase the share of wind and solar generation from 30–40% of annual system load toward New York's goal of 70% renewable energy by 2030.

This case study developed a methodology that provides a template to evaluate GETs more broadly, both in other regions and in support of other use cases. This case study is organized as follows:

- Regional screening methodology for GETs evaluation
- Overview of modeling methodologies
- Scenario development
- Grid model inputs and assumptions
- Overview of case study transmission topology
- Modeling results, including a base case without GETs deployment, with PFC, and DLRs
- Summary, conclusions, and next steps.

2.1.2 Regional Selection for GETs Evaluation

The modeling for this case study focused on a relatively small region of the State of New York to allow for a deep and detailed analysis of the local transmission network. This region was identified via a robust screening analysis across the U.S. The objective of this screening methodology was to develop a set of key indicators that could help prioritize regions and areas of the grid where GETs deployment would be most valuable. This was considered both from a cost perspective by relieving transmission congestion and from an environmental perspective by prioritizing regions with increased renewable development activity.

Generally, GETs are most valuable in areas where the existing grid infrastructure is insufficient and is projected to continue to be so in the future. As a result, a set of six key indicators were identified that could be *quantitatively* measured across the U.S. to prioritize regions of GETs deployment. These indicators are:

- Relative share of existing renewable energy
- Existing renewable curtailment
- Transmission congestion
- Locational Marginal Price (LMP) differentials
- Proposed transmission
- Proposed renewables in interconnection queues.

A brief description of these metrics is provided in Table 2.

Table 2. Description of key indicators for GETs regional screening.

No.	Key Indicator	Description	Metric	Data Source
1	Renewable Share	The variable nature of renewable generation may operate more efficiently with GETs providing transmission system flexibility to avoid curtailment and congestion.	Percent of annual energy served by wind and solar.	LBNL-2020 Wind Energy Technology Update [24] & DOE- 2018 Renewable Energy Grid Integration Data Book [25]
2	Renewable Curtailments	Indicates stress on transmission system and need to increase power flow out of renewable generation pockets.	Percent of available wind and solar energy curtailed.	LBNL-2020 Wind Energy Technology Update [24] & 2020 Utility Scale Solar Technology Update [26]
3	Transmission Congestion	Indicator of transmission system limitations that, if relieved, could facilitate the development of more renewable generation.	Annual transmission congestion cost ($), normalized by peak load.	DOE-2020 National Electric Transmission Congestion Study [3]
4	LMP Basis Differentials	Economic indicator that can help isolate localized transmission issues and their magnitude, without analyzing detailed transmission information.	$/MWh difference between the nodal LMP and zonal LMP.	DOE-2018 Renewable Energy Grid Integration Data Book [25]
5	Proposed Transmission	Indicates regions where there may be existing congestion or new resources that could be supported by GETs.	Proposed circuit line miles, normalized by peak load.	North American Electric Reliability Corporation (NERC)-Electricity Supply and Demand 2019 [27]
6	Proposed Renewables	Highlights regions where additional infrastructure may be necessary to bring new renewable resources online.	Proposed MW of new wind and solar, normalized by peak load.	Lawrence Berkeley National Laboratory (LBNL)-2020 Wind Energy Technology Update [24]

National Screening Analysis

Data on each of the six key indicators were aggregated across seven of the U.S. ISO/RTO markets by compiling a variety of publicly available data sources. For example, the Interconnection Queue for each ISO was aggregated by county and combined with U.S. Energy Information Administration (EIA) data on proposed generation additions [28]. The resulting map, provided in Figure 3, shows the amount of proposed megawatt (MW) wind and solar capacity for each county across the U.S. Brighter coloring in the figure (e.g., greens and yellows) represent counties with significant renewable energy development activity. Note that this map does not include distributed generation and in regions outside of formalized ISO/RTO energy markets, where development may be underway, but not yet officially reported to EIA. This process identified six key regions of clustered renewable development that may require additional transmission investment, which results in an increased GETs value.

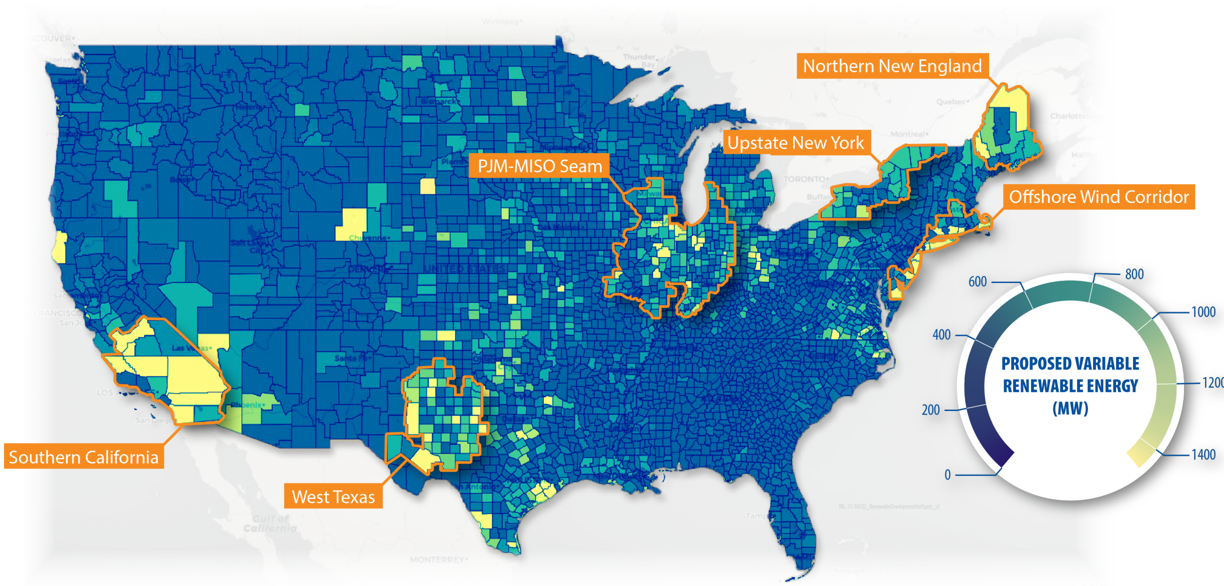


Figure 3. Map of Proposed Wind and Solar Capacity by County.

Similar data collection was conducted for other key indicators across these ISO/RTO markets. To allow for comparative analysis, each indicator was normalized either by annual energy or by peak load. The results of this analysis are provided in Table 3 for each ISO/RTO.

Table 3. Key indicators for GETs value by ISO/RTO.

		CAISO	ERCOT	ISONE	MISO	NYISO	PJM	SPP
W&S Penetration (% of Generation)		22.5	18.0	4.5	7.0	3.0	3.0	22.5
Max Instantaneous W&S (% of Load)		62.0	53.5	12.0	23.0	12.0	10.0	70.0
Curtailment (% of Energy)	Wind	0.3	2.7	1.9	5.5	1.5	0.0	1.6
	Solar	2.4	5.0	-	-	-	-	-
Transmission Congestion (M$/GW of Peak Load)		16.93	16.88	2.65	11.57	18.42	8.64	7.52
Percent of Hours with Negative Pricing		2.10	0.28	1.17	-	0.28	0.07	1.17
Proposed Transmission (Miles/GW of Peak Load)		11	13	31	36	35	7	16
Proposed Renewables (MW of Renewables per MW of Peak Load)	Wind	23	36	58	17	56	18	112
	Solar	99	72	7	42	31	37	57
	Total	122	108	65	59	87	55	169

Based on this analysis, CAISO, Southwest Power Pool (SPP), and ERCOT are leading the country in wind and solar generation as a percentage of the total generation mix. But they are also faring well with respect to curtailment relative to those levels. In contrast, NYISO has a much lower wind and solar penetration with only 3% of the total generation mix, but is already experiencing wind curtailments. In addition, NYISO transmission congestion is the highest on a per gigawatt (GW) of peak load basis, as is the amount of proposed transmission and renewable development. As a result, the NYISO market was selected for this case study.

Local Screening Analysis

Similar to the exercise of screening the U.S. to identify candidate regions for GETs, a comparable methodology was developed to identify subregions that could be most benefited by GETs. For this analysis, three metrics were evaluated, this time on a much more granular basis—either at the nodal or county level. These included the following indicators:

- **Average annual nodal LMP**, in general, refer to either high-price regions in areas that could benefit from increased imports and transmission into the region, or low price regions that indicate areas that could benefit from increased export transmission capability. Differences in the LMPs within regions are attributed to congestion and losses.
- **Basis differential** calculated as the average difference in the hourly nodal LMP relative to the average zonal LMP. In general, this metric identifies nodes that experience transmission congestion, where high values represent load pockets and low values represent generation pockets. Both could benefit from GETs additions.
- **Proposed renewable projects**, summarized on a county level based on the NYISO Interconnection Queue. Regions with higher renewable development tend to be further from load centers (e.g., high price regions in average annual LMP plot) and may require additional transmission to avoid curtailment and additional congestion.

The results of the local screening analysis are provided in Figure 4 through Figure 6. As these figures indicate, there are three or four subregions of particular interest for GETs. The State of New York has higher prices in its southeast region due to a large “Central East Interface” transmission limit, which is represented as a dotted line on Figure 4. Prices are highest in the Long Island load pocket due to limited generating resources and limited transmission to neighboring areas. Upstate New York prices are lowest due to wind generation along the Canadian border and nuclear generation along Lake Ontario.

Zonal price differentials in Figure 5 show a similar pattern, where northern New York, western New York, and Long Island have nodal price separation. In these examples, specific locations have higher or lower prices relative to the zonal average representing transmission congestion. These same regions are the ones with the most proposed renewable projects, which could further exacerbate the existing transmission bottlenecks, as shown in Figure 6. As a result, the northern New York, western New York, and Long Island subregions are potential candidates for GETs analysis and were key subregions evaluated for this case study.

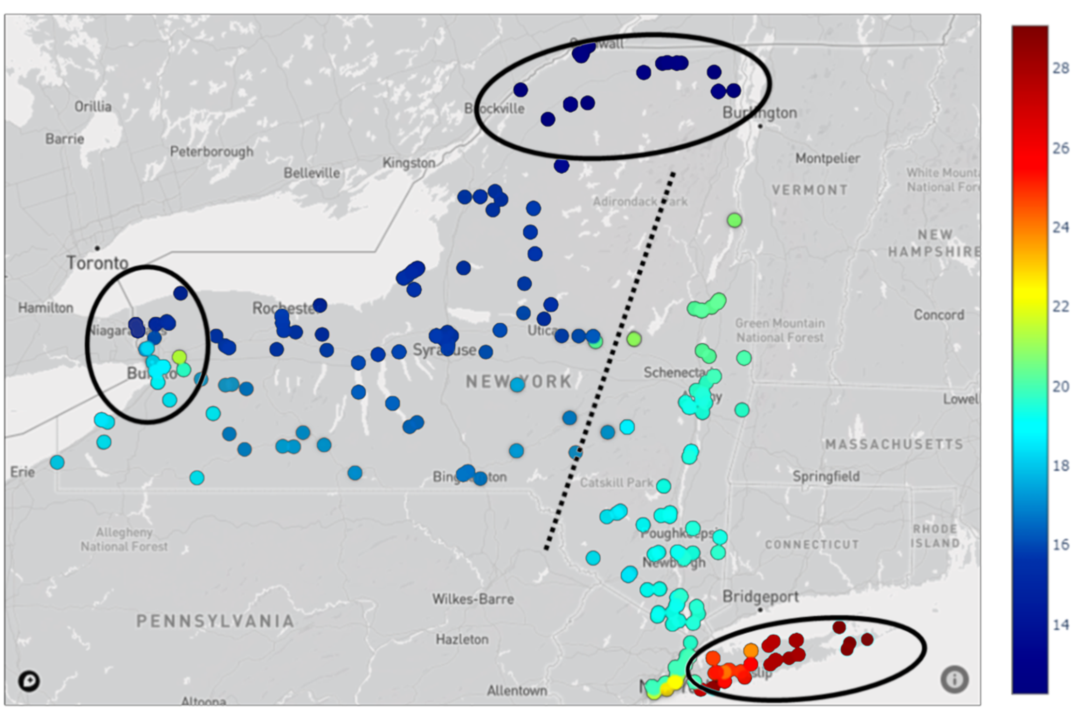


Figure 4. NYISO historical 2020 average nodal LMP ($/megawatt hour [MWh]).

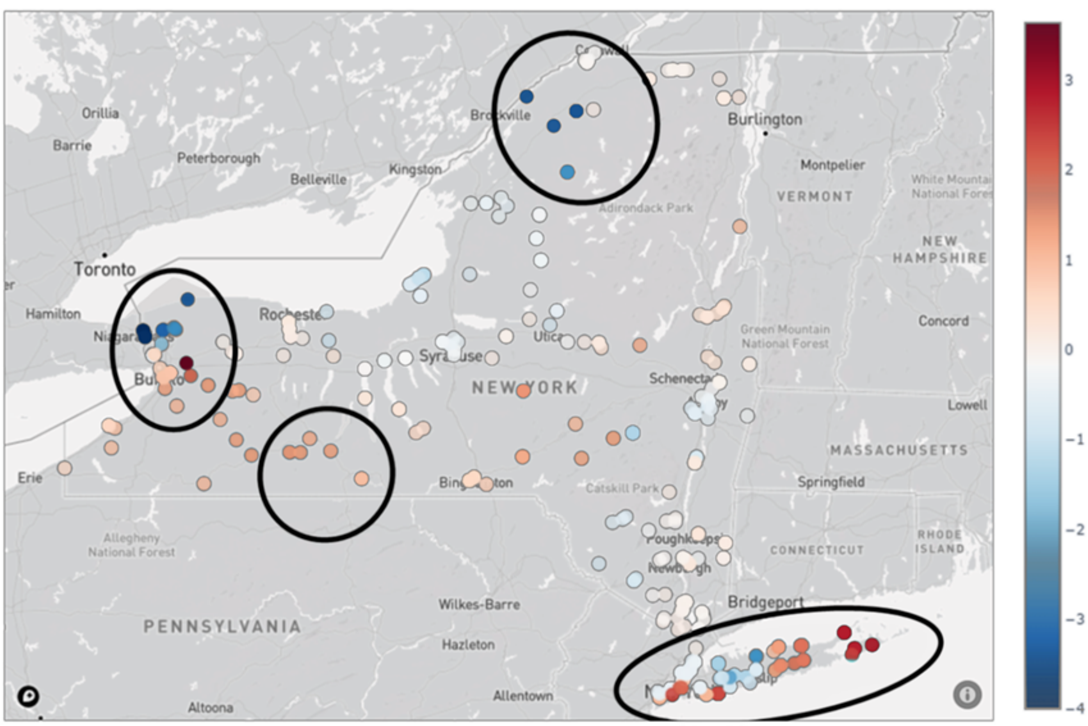


Figure 5. NYISO historical zonal basis differential.

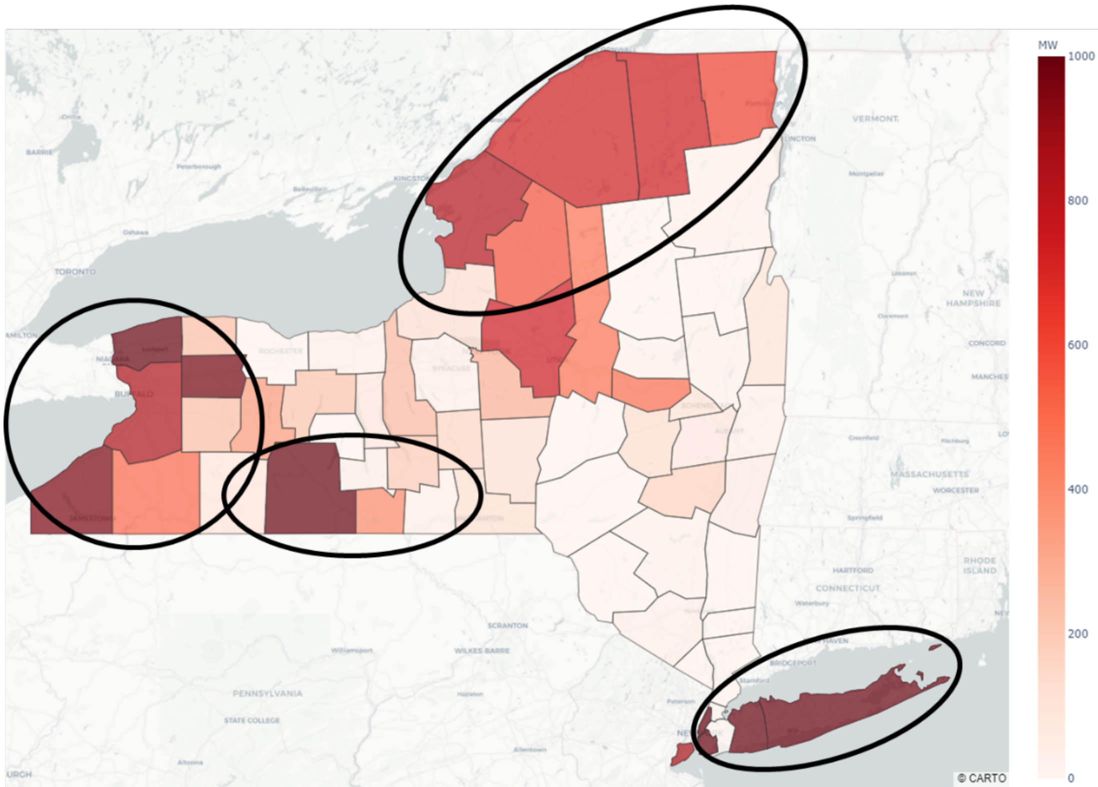


Figure 6. NYISO proposed wind and solar Interconnection Queue by county.

2.1.3 Modeling Methodology

To perform the techno-economic grid planning analysis of GETs, a set of computer simulations were completed to evaluate the system under various renewable generation mixes, both with and without proposed transmission upgrades and GETs. The grid simulations leveraged the same tools used widely throughout the power industry by utilities, system operators, consultants, and researchers. The decision *not* to use custom tools for this analysis was important as it affords two benefits: (1) it allows GETs deployment to be compared directly against other technologies (i.e., conventional transmission upgrades, battery energy storage, electric vehicles, and demand side management); and (2) it allows the process to be repeatable by a broad set of system planners.

Specifically, the techno-economic grid planning study combined two sets of tools: (1) a production cost model; and (2) a detailed AC power flow modeling software.

The first tool was a production cost model to evaluate grid operations, transmission flows, and economics across all 8,760 hours of the year. This allows for an hour-by-hour representation of the power system, considering fluctuations in load, wind, and solar output; transmission flows; DLRs that can adjust hourly; and PFC utilization. The tool selected for this study was PLEXOS, a third-party software tool developed by Energy Exemplar and licensed extensively throughout the industry. This tool was selected because of its ability to evaluate security-constrained economic dispatch, set line ratings on an hourly basis, and implement PFC devices. However, other commercial modeling software is available that could also be utilized.

Detailed AC power flow modeling software was also used to evaluate transmission security and AC power flow impacts of integrating wind, solar, and GETs. The tools selected for this analysis were Siemens PSS/E and PowerGEM Transmission Adequacy and Reliability Assessment (TARA). PSS/E is a power systems simulation tool that can be used to perform a wide variety of analysis functions, including power flow, dynamics, short circuit, contingency analysis, optimal power flow, voltage stability, and transient stability simulation. This software was coupled with PowerGEM TARA, which was used in conjunction with PSS/E for N-1/N-1-1 contingency analysis and transfer limit calculations. Both software tools are commercially licensed and used throughout the industry, but other similar tools are available to perform this type of analysis.

An important distinction for this study was the tight coupling between the economic and power flow tools, as shown in Figure 7. This methodology ensures that the power flow modeling is representative of potential system conditions. In addition, production cost modeling ensures grid upgrades can be evaluated across an entire year with many different operating conditions and be translated to economic benefits. A detailed flow chart of the study methodology is provided in Figure 8.

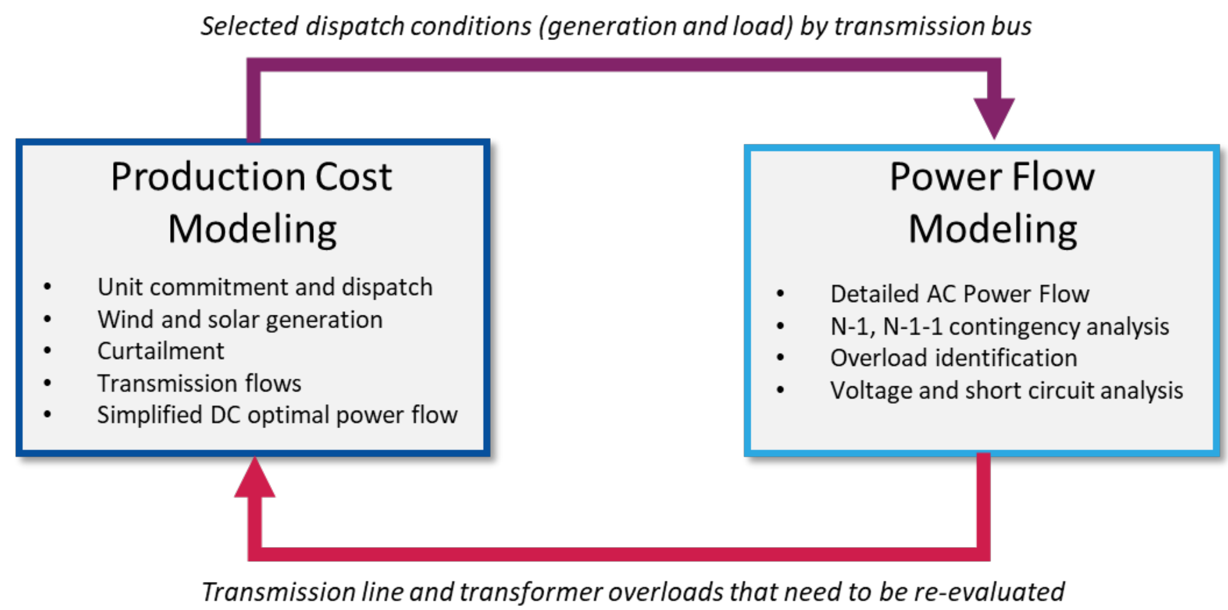


Figure 7. Model coupling between production cost and power flow tools.

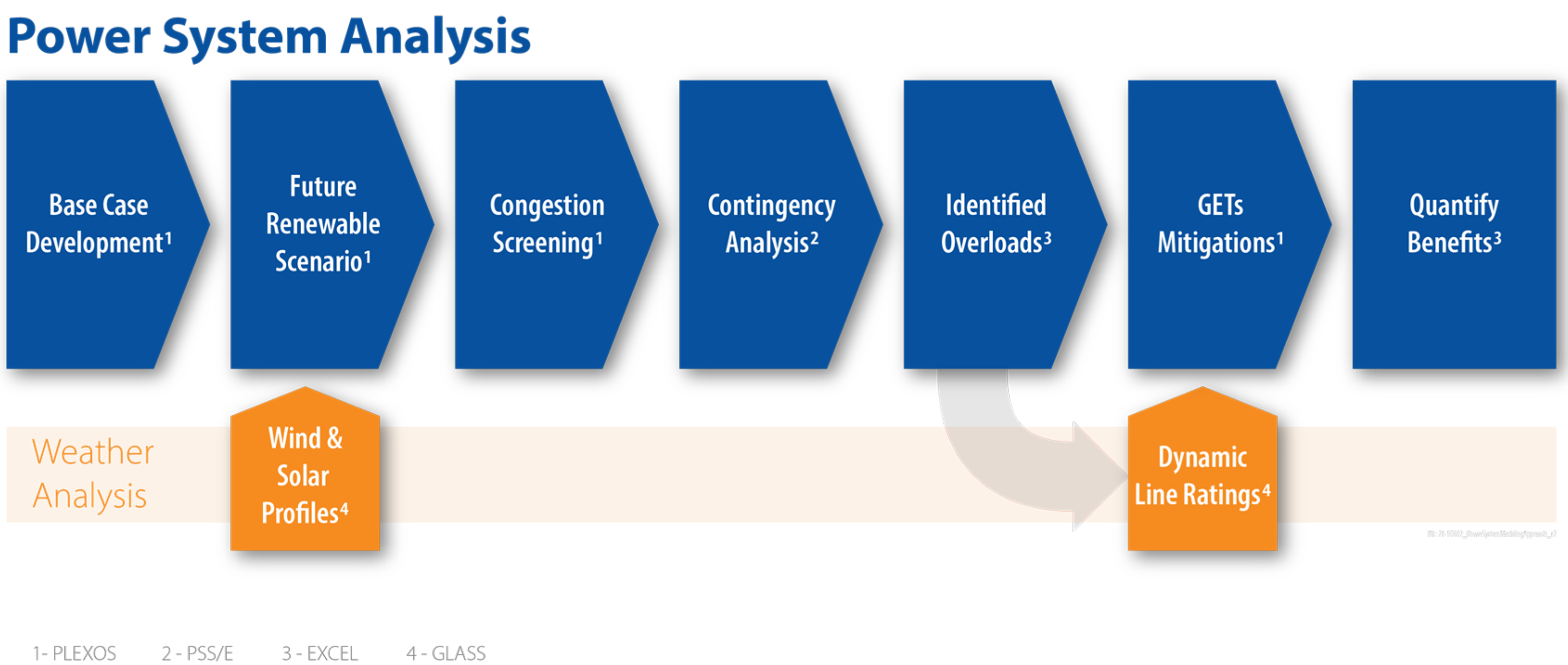


Figure 8. Grid modeling methodology flow chart.

Figure 8 provides a flow chart illustration of the techno-economic grid planning methodology. It is comprised of seven inter-related steps and exogenous analysis conducted outside of the grid model to develop weather-based DLRs and to perform cost-benefit analysis of the proposed technologies. The seven-step process is outlined below, which is a similar process used for traditional transmission planning:

Step 1: Base Case Development

The first step of the analysis established a base case dataset used for both production cost and power flow modeling. This step developed a detailed nodal production cost model of all generating resources on the NYISO system, hourly load and renewable generation profiles, and a nodal representation of the transmission network. The dataset was developed using a variety of non-proprietary sources, as well as the NYISO Federal Energy Regulatory Commission (FERC) 715 Multiregional Modeling Working Group (MMWG) transmission dataset utilized for the production cost model. This dataset was updated for a future study year, which assumed load growth, distributed photovoltaic (PV) and storage additions, fuel prices, generator additions and retirements, and proposed transmission projects. Data was shared between the production cost and power flow modeling tasks to ensure alignment across tools. Section 2.1.5 provides details on the inputs and assumptions.

Step 2: Future Renewable Buildout

The production cost model and power flow models were updated to represent a future wind and solar scenario. This was done by assuming the full NYISO Interconnection Queue for land-based wind, offshore wind, and utility-scale solar PV were built in the proposed locations, without any additional network upgrades. This was done without additional upgrades to identify the extent to which GETs could defer the need for traditional upgrades. Individual bus siting was developed based on project proposals and siting assumed in the 2019 NYISO Congestion Assessment and Resource Integration Study (CARIS) [29].

Specific latitude and longitude coordinates of wind and solar plants in the region of study were also used to develop site-specific wind and solar generating profiles. This ensures that the underlying weather data used for the generating resources was the same as the weather data utilized for the DLRs. This allows for proper correlation between the two datasets.

Step 3: Congestion Screening

The third step of the analysis conducted an 8,760-hour production cost model of the base case model with and without the renewable Interconnection Queue included. This analysis was conducted using the existing transmission network and line limits and assessed N-1 contingencies for the main transmission corridors in the region of study. This N-1 security-constrained economic dispatch, which monitors the flows across the lines and avoids *potential* overloads if a contingency were to occur. This generally occurs before a line's thermal rating is reached and is highly dependent on the ratings of the alternate power flow paths. Several dispatch conditions from this case, including generation and load at each bus, were then passed to the transmission security analysis for more detailed N-1 and N-1-1 contingency analysis performed across the entire transmission network.

Step 4: Contingency Analysis

The dispatch conditions from Step 3 were implemented in the power flow model to evaluate power transfer constraints based upon existing physical system, seasonally adjusted line rating assumptions, and available locational weather data. The output of the AC contingency analysis identified potential overloaded lines and equipment that either need to be upgraded, dispatched around, or avoided with GETs.

The outputs of Step 3 and Step 4 were then used in exogenous analysis to identify the conventional transmission upgrades necessary to relieve congestion and overloads. These capital cost estimates were then used to determine the avoided cost of new transmission infrastructure, which is a key economic benefit of GETs.

Step 5: Comparison of Production Cost Model and Power Flow Model Results

The selected cases run in the power flow model in this step were then compared against the results from the production cost model. This identified any additional overloads not identified by the production cost model and developed new interface definitions for use in the production cost model, if necessary, for reliability. This is an important step to verify the results of the production cost analysis in a security-constrained AC power-flow contingency analysis to confirm that the modeling results in the economic study would be reliable in actual operations.

The identified line segments for DLRs were then passed to exogenous modeling efforts, which utilized mesoscale atmospheric modeling to evaluate the effects of temperature, wind speed, wind direction, and other key metrics on the line limits. This modeling effort is discussed in Section 2.1.4. The outputs of this process provided a set of 8,760-hour line ratings for selected spans that were input back into the production cost model in Step 7.

Step 6: Development of List of Mitigations

The results of the congestion screening (Step 3) and contingency analysis (Step 4) were then used to identify the type and location of mitigation options necessary to avoid the transmission overloads. These include both traditional transmission upgrades and GETs. The options include the following:

- Traditional transmission upgrades, including line reconductoring, new transmission routes, and transformer upgrades
- DLRs on several overloaded transmission lines
- PFC devices added to specific line segments to either “pull” or “push” power away from over- or under-loaded circuits
- A combination of DLR and PFC devices to assess the combined value of the two technologies.
- A combination of GETs and traditional upgrades.

Step 7: Post-Mitigation Analysis

In the final modeling step, DLR and PFC technologies were added to the models to isolate the effect of the technologies on grid operations, line flows, congestion, renewable generation, and curtailment across a full year of hourly dispatch. The contingency analysis was also rerun to ensure that the DLR and PFC devices could avoid N-1 and N-1-1 contingencies. From this process, the following metrics were quantified to evaluate the benefits of GETs:

- Renewable generation and curtailment
- Hours of transmission congestion
- Overloaded line segments
- Total generation costs, including fuel costs, variable operations and maintenance costs, startup/shutdown costs, and emissions costs.
- Avoided imports
- Avoided cost of new transmission

2.1.4 Scenario Development

Three different scenarios were developed for the GETs analysis. These scenarios only differed in the amount of renewables capacity included. All other assumptions (e.g., load, transmission topology, fuel prices, etc.) were held constant across the three different scenarios. All three scenarios were modeled for the 2025 load year despite having varying levels of renewable capacity. This year was chosen as it represents a mid-point to the State of New York's first major milestone of its Climate Leadership and Community Protection Act (CLCPA) goals of 70% renewable generation by 2030 [30]. It also marks a point in time when key transmission upgrades will be completed (see Section 2.1.6). The scenarios were developed to incrementally add renewable capacity to the NYISO system and identify at which point the transmission system would become stressed, with a particular interest on the changes within the study area of the Hornell and South Perry Transmission Zone in New York. Several metrics were monitored to quantify this stress, including transmission congestion and curtailment of renewable resources. The congestion of transmission and curtailment of renewable resources are both hallmarks of a system operating at subpar levels of efficiency.

The three scenarios are:

- **The Base Case**, which evaluated the level of renewables currently built in NYISO, but layered atop the 2025 transmission topology.
- **The Interconnection Queue** scenario, which added approximately 3 GW of additional solar capacity and 4 GW of additional wind capacity from the NYISO Interconnection Queue to the system, for a total buildout of roughly 8 GW of solar and 6 GW of wind.
- The **70% by 2030 scenario**, which was created to model the approximate amount of renewable generation that would be needed to achieve the goal of the State of New York of 70% renewable generation by 2030 (an additional 16 GW of renewable capacity).

The first scenario, referred to as the **Base Case**, evaluated the level of renewables currently built in NYISO, but layered atop the 2025 transmission topology. As the name suggests, this case would form a baseline and point of comparison for other scenarios. As highlighted in Table 5, the Base Case includes roughly 5.3 GW of solar capacity and nearly 2.0 GW of wind capacity. Within the area of interest there is currently 197 MW of wind capacity. The Base Case can serve about 29% of its load from renewable resources (including hydro, landfill gas, wood, and refuse) and 46% from carbon-free resources (including the addition of nuclear). As discussed in Section 2.1.6, this relatively small number of renewables is slated to increase dramatically if all projects within the NYISO Interconnection Queue are built.

Based off the findings of Section 2.1.6, a second scenario was created, referred to as the **Interconnection Queue** case. This scenario included all renewable capacity from the Base Case and added additional capacity from multiple publicly available sources. First, all proposed projects listed in the NYISO's 2020 Gold Book Table IV-1 were added [31]. Projects awarded through the New York State Energy Research and Development Authority (NYSERDA) Renewable Energy Standard (RES) 2017–2019 solicitations were also included [32]. Then any projects from the Interconnection Queue located within Hornell and South Perry Transmission Zone, but not included in any of the above resources, were added [33]. Lastly, offshore wind projects awarded through NYSERDA's 2018 solicitation (approximately 1,700 MW) were included. Offshore wind projects awarded in the 2020 solicitation were not included because the proposed commercial online date occurs after the 2025 study year [34]. Collectively, these projects represent a significant increase in statewide renewable capacity, but are only incremental steps toward what is needed for the state to achieve its 70% renewable generation by 2030 goals as outlined in the CLCPA.

The Interconnection Queue scenario adds approximately 3 GW of additional solar capacity and 4 GW of additional wind capacity to the NYISO system for a total buildout of roughly 8 GW of solar and 6 GW of wind (see Table 5). It is important to note that about 1.8 GW of the additional wind capacity is offshore wind. As of today, all wind interconnected in NYISO has been exclusively onshore. As identified in Section 2.1.6, the Hornell and South Perry Transmission Zone is slated to see significant growth in its share of renewable generation.

The third scenario, **70% by 2030**, was created to model the approximate amount of renewable generation that would be needed to achieve New York's goal of 70% renewable generation by 2030 [30]. This scenario includes approximately 1,300 MW of additional offshore wind capacity from NYSERDA's 2020 Solicitation along with generic offshore wind capacity from future solicitations. Additionally, generic onshore wind and solar capacity were added to achieve the 70% renewable energy by 2030 State of New York goal. This generic capacity is sited and scaled proportionally to projects in the Interconnection Queue across the State of New York. With key areas-of-interest, like the Hornell and South Perry Transmission Zone, also drawing on the NYISO's 2019 CARIS siting information for generic resources [29].

In the 70% by 2030 scenario, Table 5 shows that approximately 3 GW of solar capacity and 12 GW of wind capacity were added versus the Interconnection Queue scenario. In the Hornell and South Perry Transmission Zone, a limited amount of incremental solar was added—about 9 MW—while another 1,200 MW of wind capacity was added versus the Interconnection

Queue scenario. It is important to note that this buildout enables the State of New York to achieve its goal of 70% by 2030. In this analysis, using the 2025 study year, 71% of load was served with renewable energy, while 89% of load was served with carbon-free resources, as shown in Table 4.

Both the Base Case and 70% by 2030 scenarios provide reference points and comparison for the Interconnection Queue scenario. The Interconnection Queue scenario was used to evaluate the impacts of GETs on the system, specifically their deployment in and around Hornell and South Perry Transmission Zone. Although the 70% by 2030 scenario was not used to directly evaluate GETs in this study, it is an option for next steps and in its current form served as an important calibration point for how much capacity is needed to be added to achieve the policy goals of the State of New York. Figure 9 highlights the different renewable buildout assumptions by case across each of the NYISO's zones. Each of these three cases had varying amounts of Onshore and Offshore Wind and utility-scale photovoltaic (uPV) solar, while distributed photovoltaic (dPV) solar and battery energy storage systems (BESS) were held constant.

Table 4. Renewable and carbon-free generation as percent of total load for each scenario evaluated.

	Base Case	Interconnection Queue	70% by 2030
Percent Renewable Energy	29%	40%	71%
Percent Carbon-Free Energy	46%	58%	89%

Table 5. Installed MW capacity of renewable resources by type for each scenario evaluated.

	Base Case		Interconnection Queue		70% by 2030	
Region	Solar	Wind	Solar	Wind	Solar	Wind
NYZA	719	214	1,211	1,007	2,258	3,808
NYZB	240	7	740	7	1,086	322
NYZC	690	565	1,195	1,520	1,785	3,131
NYZD	35	678	35	678	257	2,330
NYZE	646	522	1,196	820	1,931	2,501
NYZF	825	-	1,385	-	1,740	-
NYZG	560	-	770	-	885	-
NYZH	65	-	65	-	65	-
NYZI	85	-	85	-	85	-
NYZJ	564	-	564	816	564	3,741
NYZK	875	-	895	1,010	1,192	2,258
NY Total Type	5,304	1,985	8,141	5,858	11,849	18,091
NY Total	7,289		13,999		29,940	
Hornell & South Perry Zone	0	197	217	1,008	226	2,201

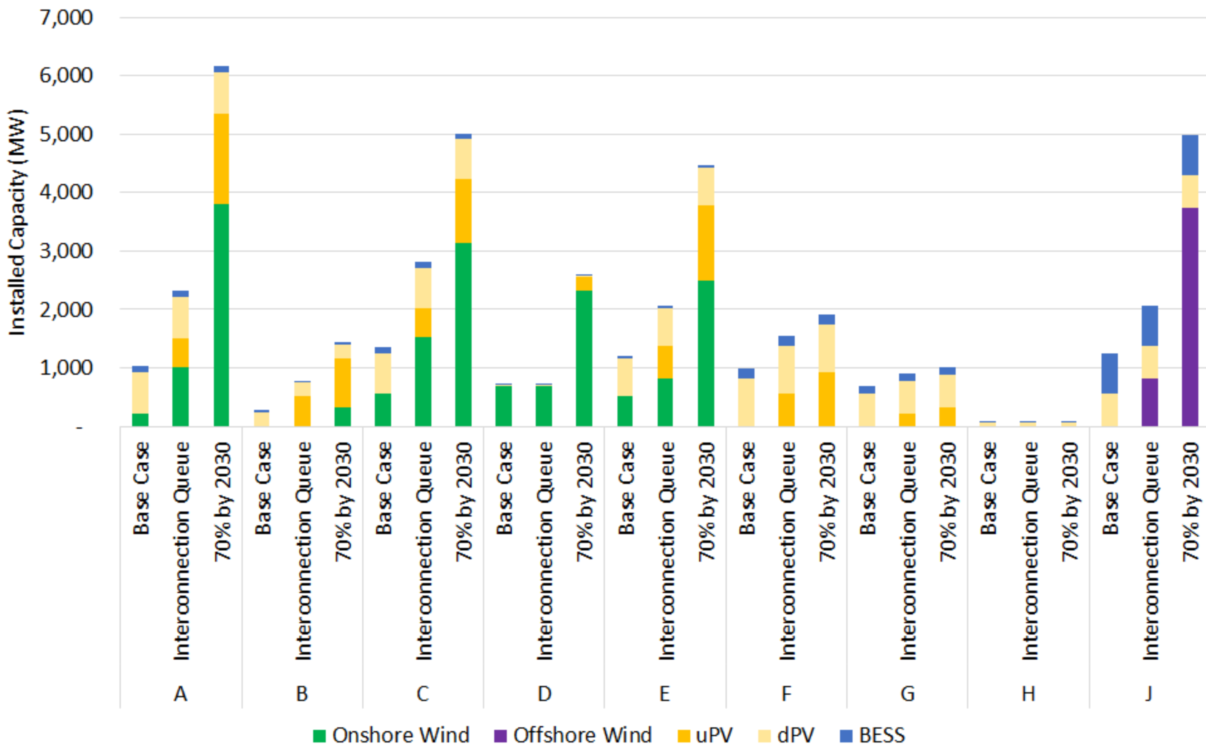


Figure 9. Renewable buildout by type for each NYISO zone and scenario.

2.1.5 Grid Model Inputs and Assumptions

For this analysis, the study team used its nodal production cost database of the New York power system. To the extent possible, inputs and assumptions were developed utilizing NYISO and the State of New York's specific data rather than generic national inputs. This makes the dataset highly applicable to and aligns with ongoing NYISO transmission planning. Annually released reports, such as the NYISO Gold Book, which outlines the most up-to-date installed capacity and load forecasts, amongst other inputs, were utilized. Other resources released on a periodic schedule, such as the NYISO CARIS report, were drawn from for their fuel price forecast and detailed siting information for future renewable additions. A full outline of resources used can be found in Table 6 and summary capacity factor information by renewable type based on production profiles provided by the project team can be found in Figure 10.

Table 6. Key inputs and assumptions for production cost modeling in PLEXOS.

Key Input	Assumption and Data Source
Installed Capacity	2020 NYISO Gold Book [31].
Generator Additions	2020 NYISO Gold Book [31].
Fossil Retirements	2020 NYISO Gold Book (Indian Point Nuclear) [31].
Generic Renewable Additions (70% Renewable by 2030)	-Installations total by type (Wind, Solar, Battery) based on Interconnection Queue percentage by NYISO zone [33]. -Rooftop Solar: 2020 NYISO Gold Book Load Forecast Assumption for distributed PV [31].
Storage Additions	Using 70% Renewable by 2030 goals of 1,500 MW by 2025 [30].
Load Data	2020 NYISO Gold Book, Peak and Energy Forecast, excluding dPV [31].
Transmission	NYISO FERC 715 Filing, MMWG19PF, Summer 2025 planning case.
Fuel Prices	NYISO CARIS 2019 Fuel Price Forecast, including area-level natural gas blends and monthly seasonality [29].
CO_2 Price	NYISO CARIS 2019 Emission Allowance Price Forecasts [29].
Generator Heat Rates	EPA CEMS data, based on hourly generation and fuel consumption [35].
Wind and Solar Profiles	NREL National Solar Radiation Database [36] and Wind ToolKit [37]for statewide profiles. Custom profiles developed by the project team for the Hornell and South Perry Transmission Zone to allow for correlation with DLR.
Imports/Exports	Historical hourly flows, with ability for imports to be reduced before renewable curtailment [38].

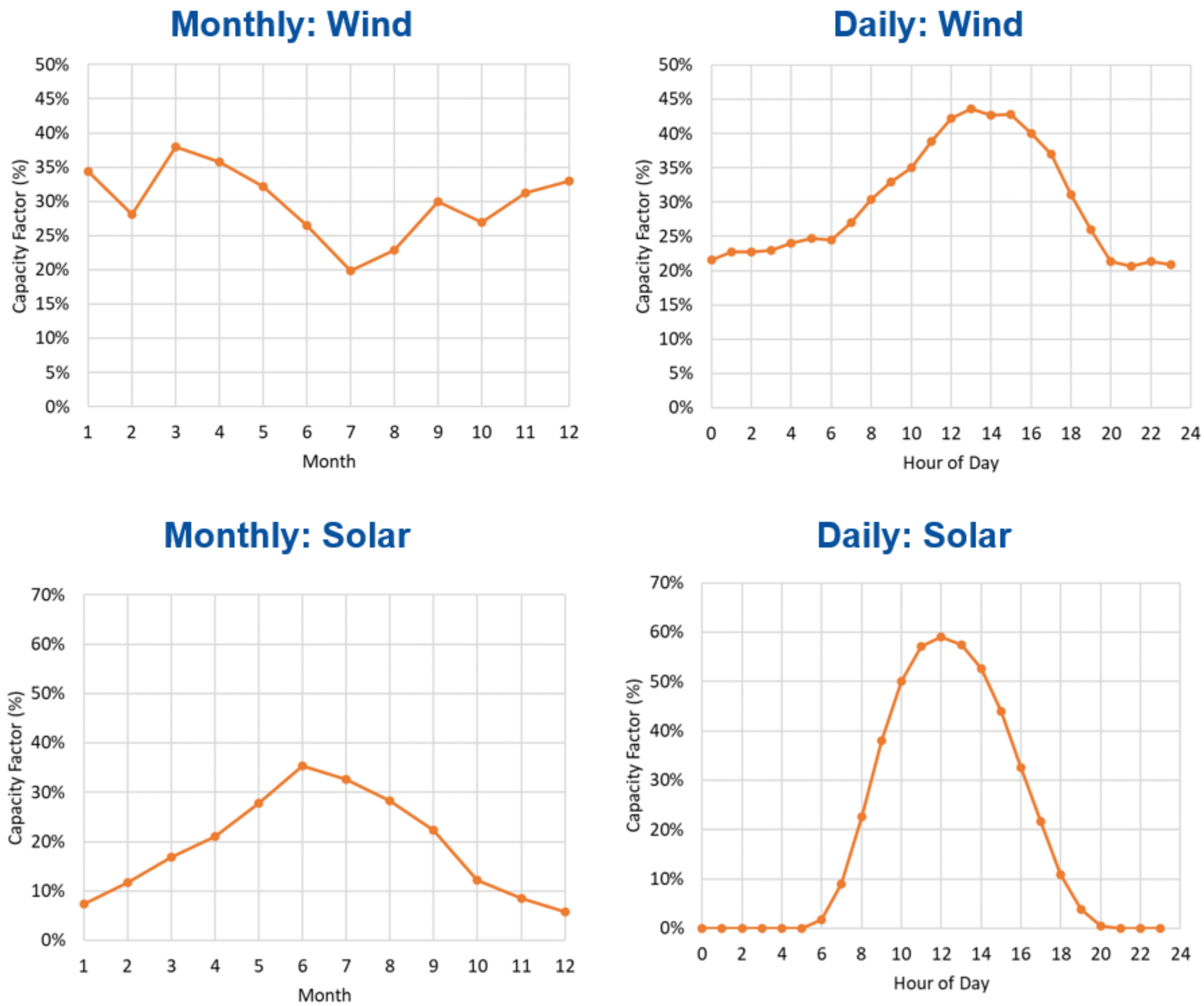


Figure 10. Monthly and daily capacity factors by resource type using Idaho National Laboratory-provided production profiles.

2.1.6 New York Transmission Topology

As discussed in Section 2.1.2, NYISO was selected as the regional case study for this analysis because it has existing wind curtailments despite low overall penetration, high congestion costs, and large proposals for new transmission and wind and solar resources. To integrate the large amounts of wind and solar resources needed to achieve the state's 70% renewable energy goal by 2030, significant transmission investment is required. The use of GETs and other enabling technology can help facilitate this transition as well, and potentially defer conventional transmission upgrades.

NYISO has already made progress identifying several potential Renewable Energy Zones throughout the state that would facilitate renewable growth. Targeted transmission and GETs deployment in these regions could accelerate those goals. Figure 11 provides a map of the transmission network of the State of New York with regions selected showing potential Renewable Energy Zones located across the state. Importantly, these regions are highly aligned with the GETs subregion screening presented in Section 2.1.2, indicating that GETs technologies will also help facilitate renewable energy growth.

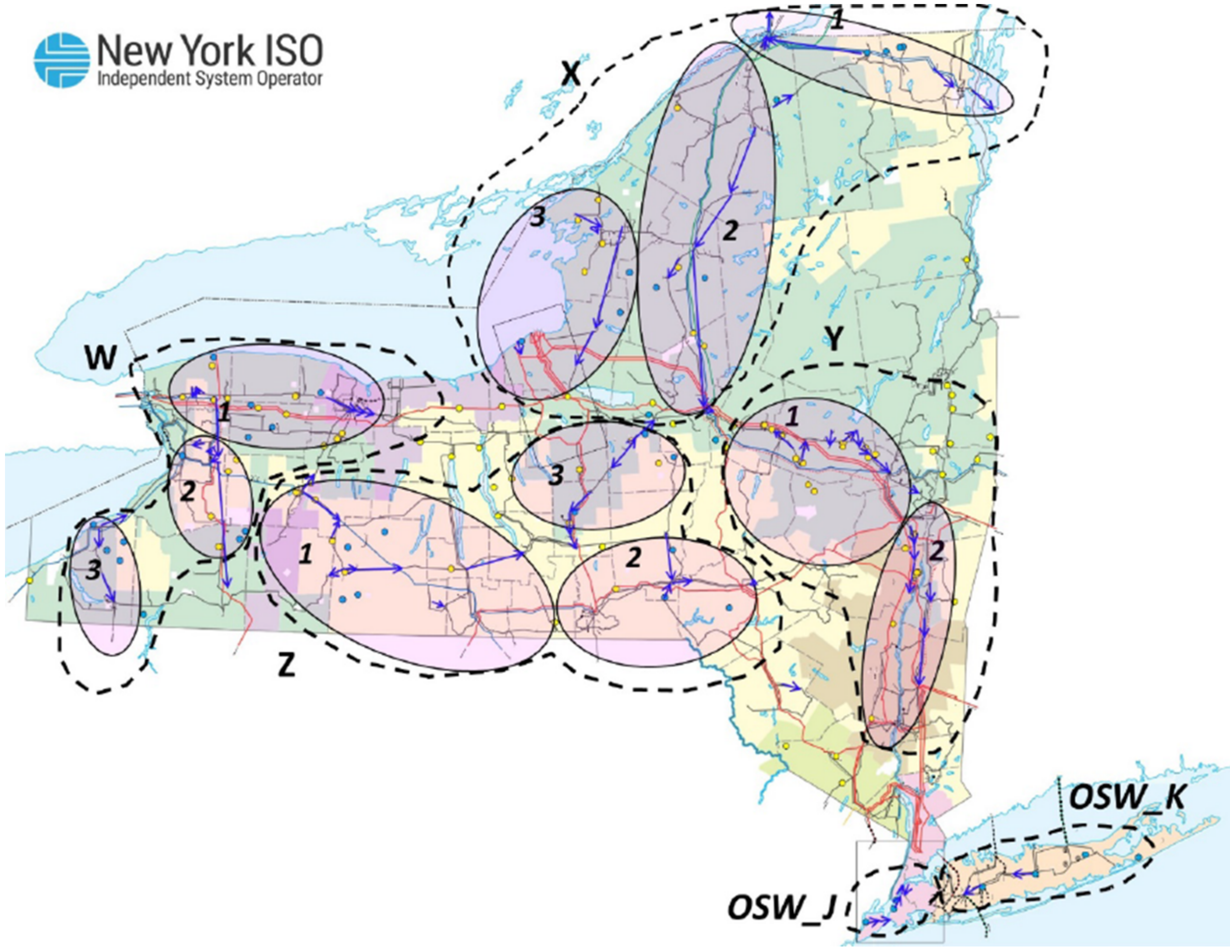


Figure 11. NYISO Renewable Energy Zones (Source: NYISO 2019 CARIS).

The case study presented in this report focused on a specific Renewable Energy Zone, indicated as “Zone Z1,” located in the Southern Tier of Upstate New York. An enlargement of the state’s transmission map is provided in Figure 12, which illustrates the transmission topology of the Avangrid Hornell and South Perry Transmission Zone. This region was selected for this case study for the following reasons:

- Several wind and solar projects are currently being developed in the NYISO Interconnection Queue, representing over 1,000 MW in the Hornell and South Perry Transmission Zone —the highest level anywhere in the state for onshore wind and utility-scale PV.
- The region has high wind generation potential and is likely well-suited for additional development, provided the transmission network can accommodate it.
- Limited existing transmission capacity is in the region, with a single 230-kV backbone cutting across the zone, along with a single 115-kV loop.

- Many transmission lines are crossing the region, which allow for multiple parallel paths for PFCs to optimize flow on.

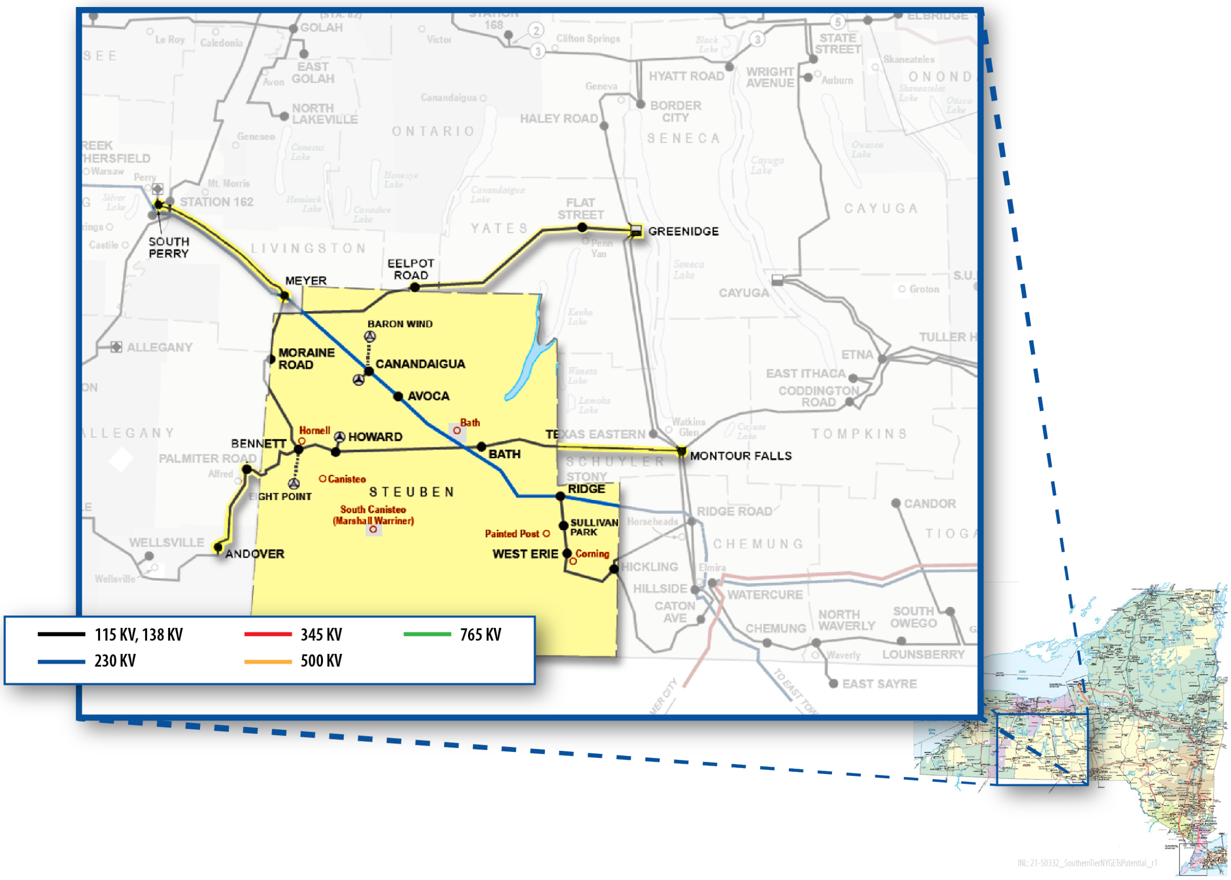


Figure 12. Transmission topology of the Hornell and South Perry Transmission Zone.

The transmission map above was used in conjunction with the Homeland Infrastructure Foundation-Level Data (HIFLD) dataset for transmission infrastructure [39]. This allowed geo-located shapefiles to be created for the transmission line segments and electrical buses, as shown in Figure 13. These coordinates were then used in the calculation of DLRs across the study footprint. The specific line segments, line names, HIFLD identification numbers, and power flow ratings are provided in Table 7.

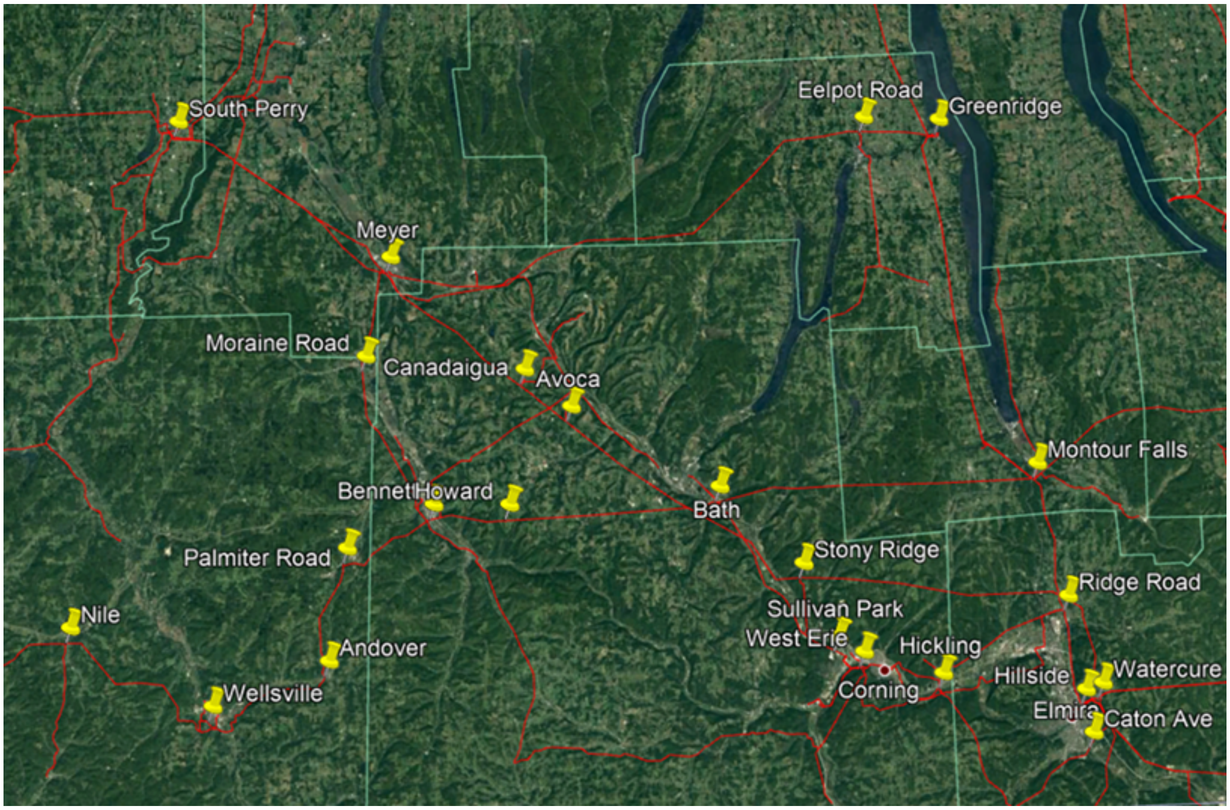


Figure 13. Geographic coordinates of transmission infrastructure in Hornell and South Perry Transmission Zone.

Table 7. Case study transmission topology evaluated for DLR and PFC

HIFLD Object ID	Voltage (kV)	Line Name	Normal Rating (MW)	Emergency Rating (MW)
44744	230	Avoca to Stony Ridge	498	534
59609	230	Canandaigua to Avoca	498	534
70455	230	Canandaigua to Meyer	498	574
36701	230	Meyer to South Perry	430	494
50571	230	Hillside to Stony Ridge	498	534
48133	115	Moraine Road to Bennett	125	152
55259	115	Bennett to Howard	124	139
60811	115	Bath to Montour Falls	124	139
70212	115	Meyer to Moraine Road	125	152
76338	115	Bennett to Palmiter Road	78	85
78517	115	Bath to Howard	124	139
30131	115	Meyer to South Perry	82	96
45562	115	Palmiter Road to Andover	79	101
45997	115	Flat Street to Greenidge	108	128
67481	115	Eelpot Road to Flat Street	108	128
70318	115	Eelpot Road to Meyer	108	128

2.1.7 Base Case Results without GETs Deployment

The first set of modeling runs conducted for the case study were to evaluate the existing and proposed power grid *without* GETs incorporated. This provides a set of reference cases to compare against simulations with PFC and DLR included. As discussed in Section 2.1.4, two reference points were included to represent the current power system **(Base Case)** and one with a large deployment of wind and solar including the NYISO Interconnection Queue and awarded New York Renewable Energy Standard projects **(Interconnection Queue)**.

The Interconnection Queue scenario was intentionally selected to stress the current transmission network and would lead to overloads without specific upgrades for those projects. This scenario approach allows the case study to isolate several important changes taking place on the system. This is valuable information to identify potential locations for GETs implementation and necessary to isolate and quantify the changes and benefits that can be attributed to GETs. As a result, the following information was quantified:

- Locations of increased transmission flows attributed solely to an increase in renewables

- Direction of transmission flows due to increased renewable generation
- Location of transmission overloads, including line segment and transformers
- Periods with renewable curtailment required.

Table 8 provides an annual summary of line flows across a selected set of important line segments in the Hornell and South Perry Transmission Zone. It includes four line segments along the 230-kV backbone crossing through the region, as well as seven selected line segments on the 115-kV loop.

The data include MW information on the normal SLR for the line, annual line flows in the forward and reverse direction, and a metric of line loading. Note that the direction of line flow is determined based on the naming convention (i.e., for Canandaigua to Avoca, forward flow represents flow from the Canandaigua substation toward the Avoca substation, while reverse flow is in the counter-reference direction). Line loading represents the total amount of flow across the line (i.e., absolute value of the total forward and reverse flow) throughout the year relative to the capability of the line if it were fully loaded for the entire year. It is analogous to a generator's capacity factor. The line loading is also included graphically in Figure 14.

Total line loading is used in this report as a key metric measuring the overall use of the transmission infrastructure. In general, the transmission system is designed around peak load and generation periods, which is underutilized most of the year. The higher the line loading on average, the more the existing transmission infrastructure is getting utilized throughout the year. Low numbers represent a potential inefficient use of the network, but high values could indicate a need for new transmission investments, which is a valuable metric to assess GETs because it quantifies the additional use of *existing* assets that can be achieved by deploying GETs.

From this data, the following observations can be made:

- In the Base Case, without renewable additions, line flows generally occur from west to east across the network, pushing power from South Perry in the northwest to Stony Ridge and onto Elmira in the Southeast.
- In the Interconnection Queue case, which excludes required traditional network upgrades, the west to east flows continue, but there is also increased flow reversing back toward South Perry in the west. This represents a general need to push power out of the renewable generation pocket in both directions.
- The weighted average line loading in the Hornell and South Perry Transmission Zone increases from 21% to 35% with the increase in wind and solar generation in the region.
- The largest increase in line loading occurs from Canandaigua to Stony Ridge (i.e., the primary 230-kV conduit on which wind generation is added), and from Bennett to Bath (via Howard) along the southern portion of the 115-kV loop where additional wind and solar is added.

Table 8. Selected line flows in study region, without GETs deployment.

		Canandaigua to Avoca	Canandaigua to Meyer	Avoca to Stony Ridge	Meyer to South Perry	Bath to Moraine Rd.	Bath to Howard	Meyer to Moraine Rd.	Meyer to South Perry	Moraine Road to Bennett	Bennett to Palmiter Rd.	Bennett to Howard	Network Total
	Limit (MW)	498	498	498	430	124	124	125	82	125	78	124	
	Voltage (kV)	230	230	230	230	115	115	115	115	115	115	115	
Base Case	Forward Flow (GWh)	896	37	927	7	140	1	228	6	166	38	190	
	Reverse Flow (GWh)	10	604	8	1029	14	348	0	126	1	112	11	
	Total Flow (GWh)	906	640	936	1036	154	349	229	133	166	149	201	4899
	Utilization (%)	21	15	21	28	14	32	21	18	15	22	19	21
Interconnection Queue	Forward Flow (GWh)	1870	276	1904	175	430	0	94	94	79	97	549	
	Reverse Flow (GWh)	1	648	1	885	1	674	144	76	65	175	0	
	Total Flow (GWh)	1871	924	1904	1060	431	674	239	170	144	272	549	8237
	Utilization (%)	43	21	44	28	40	62	22	24	13	40	51	35

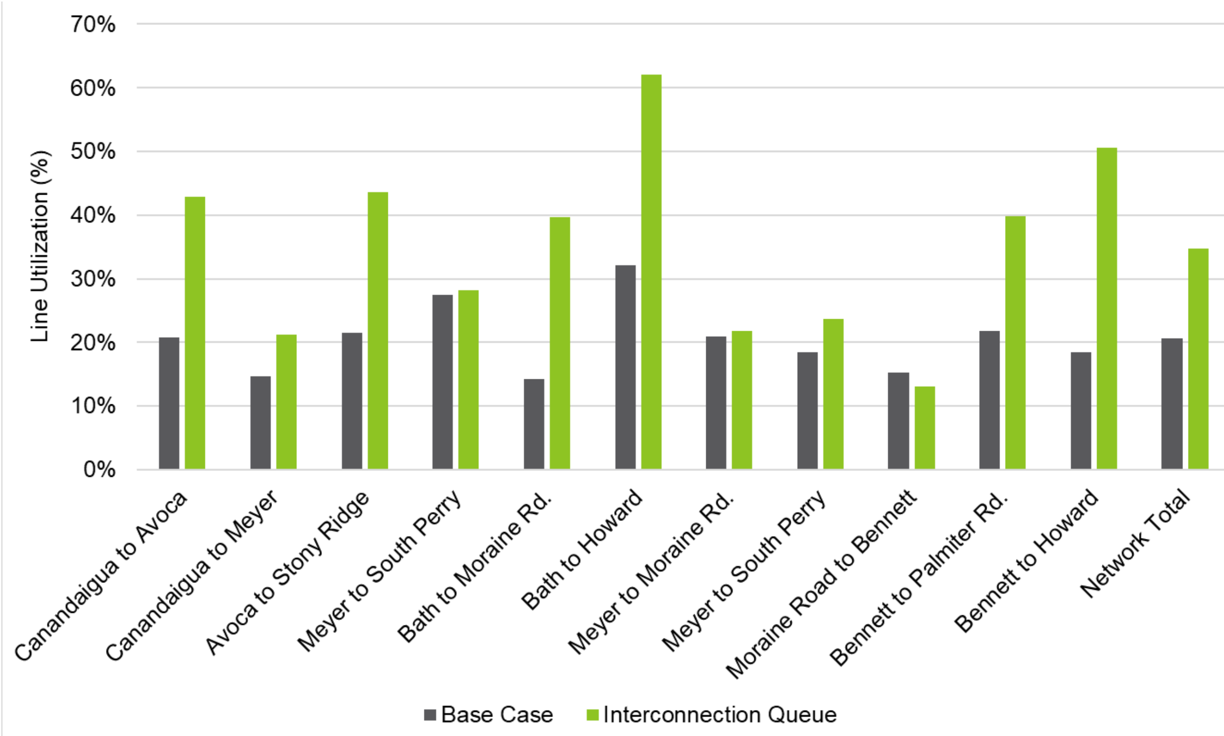


Figure 14. Annual line loading for selected lines in study region, without GETs deployment.

While the annual flows presented in Table 8 and Figure 14 are important to summarize annual changes taking place on the transmission system, flows must be monitored and balanced in real-time and can change both in magnitude and direction from hour-to-hour. To summarize the hourly line flows across the network, a series of line flow duration curves are provided in Figure 15. The duration curves quantify the *hourly* line flows and sort the 8,760 hourly observations from highest to lowest throughout the year. This provides a distribution of hourly line flows as opposed to the annual metrics.

For example, the plot on the left shows hourly line flows increasing on the Canandaigua to Avoca 230-kV line segment from the Base Case (green line) to the Interconnection Queue case (blue line) when renewables are added. In general, this represents an increase of approximately 100–200 MW per hour and brings the line flows up closer to the thermal 498 MW line limit during some hours (note that the line becomes binding due to N-1 contingency limits prior to that point). In this case, the flow is almost always positive, representing forward flow from Canandaigua to Avoca. Negative flow, as seen most noticeably in the center chart for Bath to Howard represents backward flow along that line segment. Therefore, during most hours of the year flow is going from Howard to Bath.

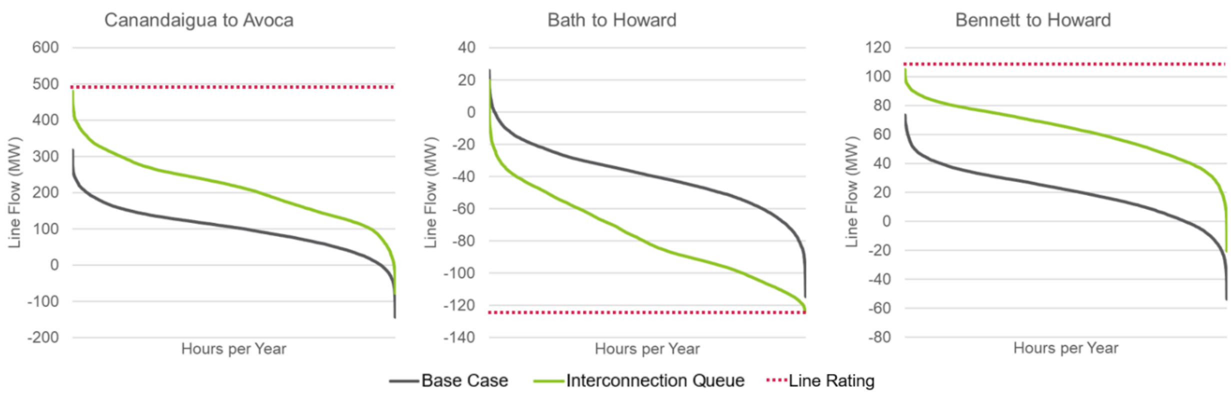


Figure 15. Line flow duration curves for selected line segments, without GETs deployment.

The charts provided in Figure 15 show line flows relative to their thermal limits. However, congestion can occur at flows much lower than the thermal rating when considering contingencies. In this context, a given transmission line may not be operating at or near its rated capacity, but its flow is limited because if the line unexpectedly tripped, the flow would immediately divert to other connected paths, which would then be overloaded.

Figure 16 provides the hours of line congestion throughout the year caused by N-1 contingency constraints. For example, the South Perry to Meyer 230-kV line flow is limiting approximately 2,000 hours per year in the Base Case because if that line were to trip unexpectedly, line flows would shift and overload other lines in the network. This congestion increases by 50% to 3,000 hours per year in the Interconnection Queue case because additional renewables are added to the line. This analysis clearly shows that the increase in congestion occurs predominantly on the 230-kV path from South Perry to Stony Ridge because in a line contingency event, the 115-kV network, which has a significantly lower capacity than the 230-kV network, would be overloaded.

This increased congestion is problematic for two reasons: (1) it leads to increased congestion costs because the grid's resources cannot be committed and dispatched optimally from an economic perspective; and (2) it leads to curtailment of wind and solar resources in the region that must limit production to avoid a potential overload on the transmission network if a line goes out of service. Congestion on these lines due to N-1 contingencies can potentially be alleviated with PFC devices that balance flows across the network, as well as DLR that can increase the line ratings based on ambient conditions. Therefore, these line segments, and the associated overloads in an N-1 contingency, create a priority list for GETs deployment and conventional transmission upgrades. Note that the specific line segments overloaded due to N-1 contingencies were included in the simulations, but not reported due to confidentiality requirements.

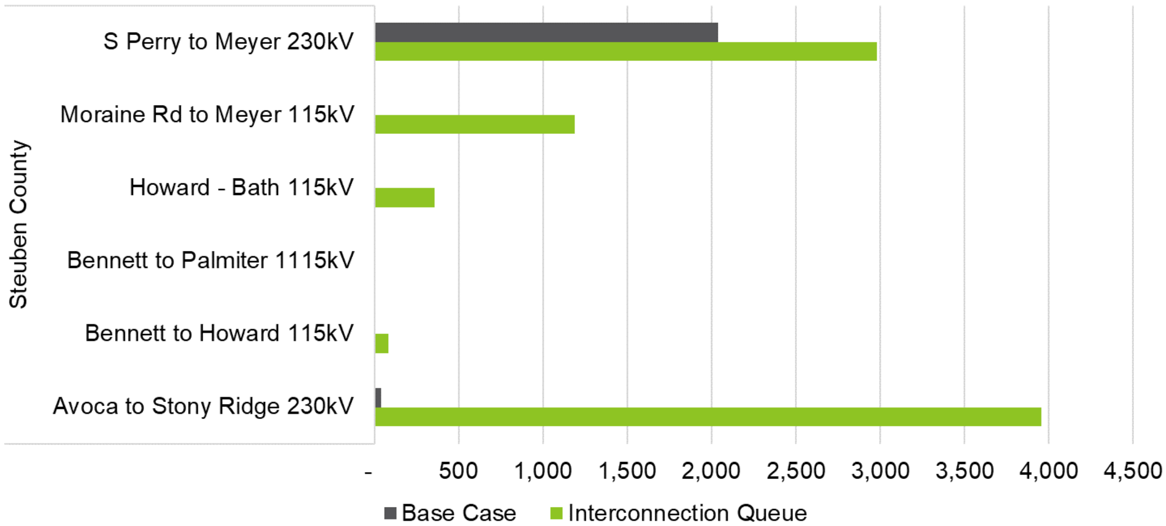


Figure 16. Hours of line congestion due to N-1 contingency constraints, without GETs.

Table 9 provides the summary data for the total renewable energy in the Hornell and South Perry Transmission Zone. The resulting monthly wind and solar generation and curtailment in the Hornell and South Perry Transmission Zone is provided in Table 10. Note that there was no curtailment in the Base Case, so all curtailment is incremental due to the increased renewables, and prior to GETs additions. This curtailment represents wasted, or "spilled," renewable energy that cannot be accepted by the grid due to transmission limitations. Curtailment is highest in the spring and fall months when load is lower and renewable resources, namely wind production, is higher.

Table 9. Summary data for the total renewable energy in the Hornell and South Perry Transmission Zone: Base Case versus Interconnection Queue.

	Base Case	Interconnection Queue
Wind & Solar Available (GWh)	513	2,980
Wind & Solar Generation (GWh)	513	2,545
Wind & Solar Curtailment (GWh)	0	434
Wind & Solar Curtailment (%)	0	15

Table 10. Monthly renewable generation and curtailment for renewables within the Hornell to South Perry Transmission Zone for the Interconnection Queue case.

Month	Total Renewable Generation (GWh)	Total Renewable Energy Curtailed (GWh)	Total Renewable Curtailment Factor (%)
Jan	214	53	20.0
Feb	182	23	11.1
Mar	262	49	15.8
Apr	233	58	19.8
May	232	52	18.3
Jun	216	29	11.8
Jul	188	12	5.8
Aug	192	24	10.9
Sep	221	30	12.1
Oct	186	35	15.7
Nov	206	32	13.6
Dec	213	39	15.3
Annual	2,545	434	14.6

All other things being equal, this generation spilled due to transmission congestion or lack of load must be replaced by other resources on the system, namely natural gas-fired resources located in less-constrained regions of the grid. The overabundance of generation also has the effect of lowering the market clearing price. If additional transmission and/or GETs were added in conjunction with renewables, this curtailment could be avoided. As a result, this avoided curtailment would yield benefits to the system, and ultimately be realized by the ratepayer, as listed below. From this, the avoided curtailment established the value of new transmission additions and GETs.

Benefits of Reduced Curtailment

- Reduction in fossil fuel consumption
- Decreased fuel costs and other production costs (e.g., voltage Operation and Maintenance [O&M], startup shutdown costs, emissions costs)
- Lower CO_2 emissions
- Fewer wind and solar installations needed to meet the state's renewable energy targets.

2.1.8 Simulation of Dynamic Line Ratings

The first GETs evaluated in the case study was the implementation of DLR across the 115-kV and 230-kV network. As discussed in Appendix A, this area's transmission topology is established around a single 230-kV transmission line, which serves as the main transmission corridor for the region (see the blue line in Figure 17). The 230-kV line bisects the study area from South Perry in the northwest to Stony Ridge in the southeast and serves as a conduit for much of the renewable capacity being added in the Interconnection Queue scenario. Load and generation in the region are also supported by a 115-kV loop for greater connectivity.

As shown in Figure 17, a total of sixteen line segments in the Hornell and South Perry Transmission Zone were evaluated with DLRs deployed. The DLR line segments evaluated were implemented until the transmission zone interconnected with the larger NYISO grid at South Perry, Elmira, and Greenidge. This was done to enable lines with DLRs deployed to distribute any increased flow across multiple lines. This implementation allowed for the greatest value of DLRs to be realized and avoided pushing transmission bottlenecks to simply the next line segment. Once the increased flow reached the larger grid with multiple transmission paths, congestion was effectively reduced.

The simulations with DLRs allowed the line rates to fluctuate on an hourly basis based on ambient conditions (e.g., temperature, wind speed, wind direction, solar irradiation, etc.). At times, higher flow was permitted across the network because a line's static thermal rating could be increased due to weather conditions that reduced sag and equipment stress. However, there were times that a line's dynamic rating was below its static rating due to warmer temperatures and minimal wind cooling.

It is also important to note that the DLRs use the same underlying weather data as the wind and solar production profiles to ensure proper correlation. The wind that increases wind energy production in a region is also capable of cooling nearby transmission lines, thereby increasing their rating and potentially leading to a reduction in curtailment. This coincident effect was analyzed in this study.

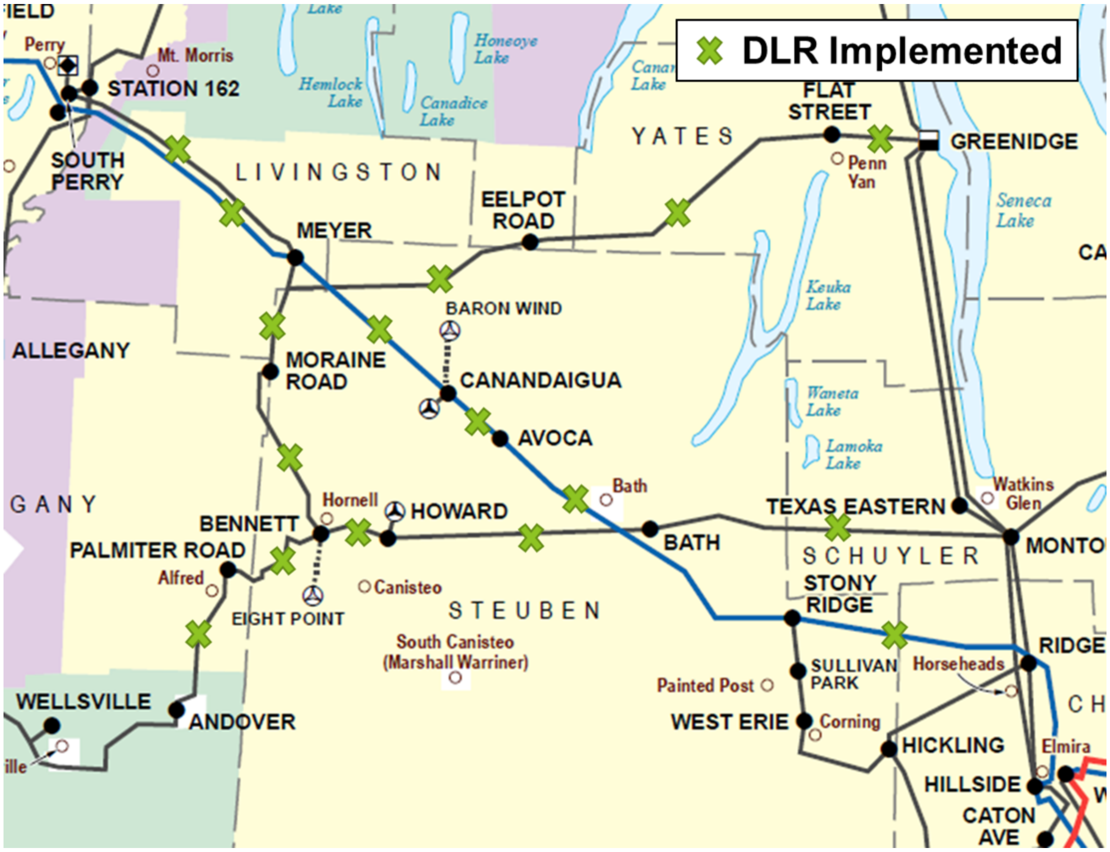


Figure 17. Transmission map with dynamic line ratings deployed.

By deploying DLRs on select lines within the Hornell and South Perry Transmission Zone, many of the lines can more fully utilize their potential as compared to the limits of their SLR. This results in lines having the ability to safely carry power above their listed SLR. The Flat Street to Greenidge line segment DLR was 113% of the SLR on average across the year. Overall, out of the sixteen line segments where DLR is deployed, twelve have average DLR ratings at or above their SLRs. The four line segments with DLR averages below their SLRs can, on average, have as low as 94% of the flow of the static rating. A summary of these statistics is shown in Table 11.

As highlighted in Table 11, the line segment from Canandaigua to Avoca has a DLR that is 108% higher than its SLR on average. However, the DLRs have a minimum rating that is only 383 MW versus the SLR of 498 MW, indicating that at some points during the year, ambient conditions require a *decrease* in line rating relative to the static rating. Figure 18 shows a duration curve of the DLR, the DLR with a floor at the SLR, and the SLR.

For this analysis, DLR limits were used even if they dropped below the SLRs, meaning that even for a line segment that on average was 108% higher than its SLR, there would still be over 2,000 hours where its DLR was less than its SLR. While this would increase congestion costs and potential curtailment during these hours—thus increasing system costs as well—it is expected to yield reliability benefits as the system operator has increased visibility to operate the grid at appropriate line ratings to avoid equipment failures or safety risks.

Table 11. Annual dynamic line rating statistics by line segment.

	SLR (MW)	Min DLR (MW)	Avg DLR (MW)	Max DLR (MW)	DLR as a % of SLR (%)
Canandaigua to Meyer	498	383	517	880	104
Canandaigua to Avoca	498	383	539	1036	108
Avoca to Stony Ridge	498	387	510	806	102
Hillside to Stony Ridge	498	383	500	710	100
Meyer to South Perry	430	329	462	763	107
Meyer to Moraine Road	125	92	137	224	110
Bath to Montour Falls	124	92	128	222	103
Bennett to Howard	124	91	133	269	108
Bath to Howard	124	91	125	207	100
Moraine Road to Bennett	125	92	127	207	102
Flat Street to Greenidge	108	80	122	202	113
Eelpot Road to Flat Street	108	78	105	182	97
Eelpot Road to Meyer	108	77	106	159	98
Bennett to Palmiter Road	78	53	73	133	94
Meyer to South Perry	82	56	85	139	104
Palmiter Road to Andover	79	53	75	128	95

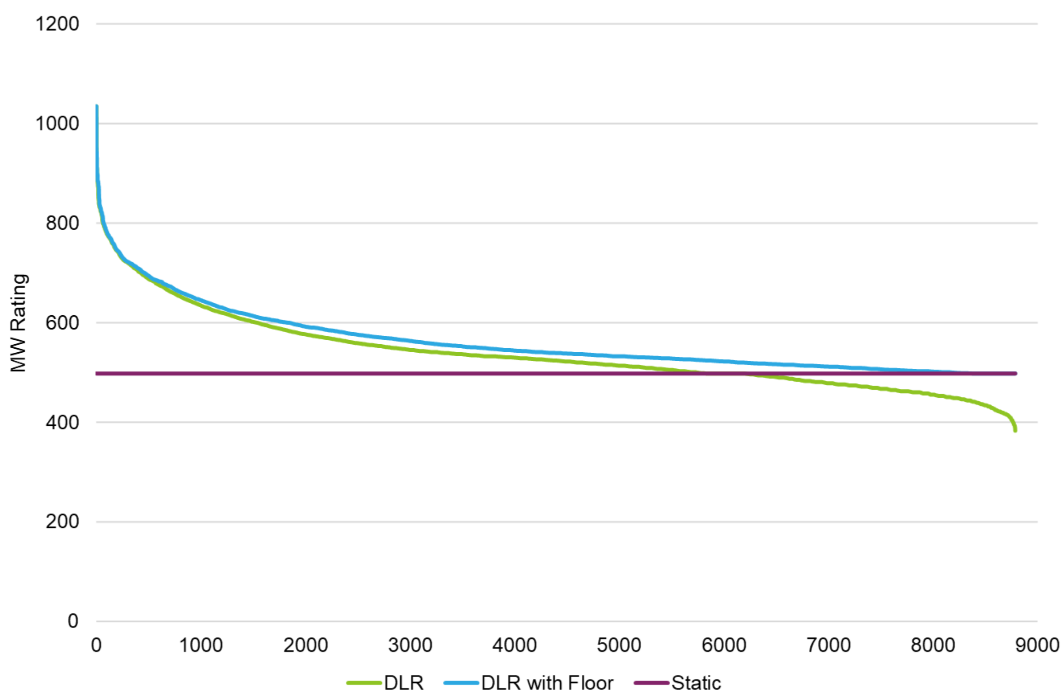


Figure 18. Hourly duration curve of line ratings for Canandaigua to Avoca 230 kV.

Hours below the SLR are not equally distributed across the entire year, but have a clear seasonal trend. Just as Figure 10 highlighted the average low-monthly capacity factor of wind generation during the summer months, Figure 19 highlights the limits of DLR during this time.

This is because wind speeds are lower and do not cool the transmission lines as much, and ambient temperatures are higher. Note that the DLR and wind production inputs to the simulation models relied on the same underlying dataset. Therefore, an increase in wind speed not only increases wind production, but also the DLRs of the nearby lines, so it makes sense that the period of the year with the lowest wind production also experiences the lowest DLRs. Fortunately for wind generation resources, this coincidence results in little to no negative impacts on curtailment. However, those same charts in Figure 10 highlight solar production's peak seasonal period as the same summer months.

Figure 19. Change to dynamic line rating relative to static line rating for Canandaigua to Avoca 230-kV line.

While wind resources may not be negatively impacted by a lower DLR than the SLR due to correlation of the resources, solar generation is negatively impacted. This is because the highest solar generation occurs during the May through September timeframe when DLR, on average, drops to near or below static ratings. This is most pronounced in solar's increase in curtailment from 42% of annual available energy in the Interconnection Queue scenario to 47% in the With DLRs scenario. However, it is important to note that solar is a relatively small part of the Hornell and South Perry Transmission Zone area's capacity and generation. The total curtailment of all renewable generation still decreases on an annual basis by 1.4% versus the Interconnection Queue reference case with static line ratings, but the overall reduction in curtailment is small because of the increase in the summer months.

It should be noted that this finding is potentially unique to the case study evaluated. Had the DLRs been higher, or at least unchanged, relative to SLRs during the summer months, the annual curtailment reductions and ratepayer savings would have been much larger. The same is true if the resource mix has less solar generation, illustrating that all other things being equal, DLRs may be more important for wind generation regions rather than for solar. It is important to note that despite the unique limitations of DLRs in this area, they still provided a valuable reduction in curtailment, as depicted in Table 12 and Table 13, respectively.

Another way to judge the impacts of DLRs on the system is to look at how line loadings have changed with their introduction. Figure 20 shows the line loadings of key line segments in and around the Hornell and South Perry Transmission Zone area. Although Table 11 showed that twelve of the sixteen lines now have higher line ratings on average with DLRs, these changes are not evident in the line loading data. Although six line segments in Figure 20 show an increase in line loading, the increase is not commensurate with the increase in the average rating of those respective lines.

Table 12. Annual wind and solar (W&S) generation and curtailment with and without DLRs.

	With SLRs	**With DLRs**
Total W&S Available (GWh)	2,980	2,980
Total W&S Generation (GWh)	2,545	2,585
Total W&S Curtailment (GWh)	434	395
Total W&S Curtailment (%)	15	13
Avoided Curtailment (GWh)*	-	40
Avoided Curtailment (%)*	-	9

* Relative to Interconnection Queue reference case with static line ratings

Table 13. Monthly renewable curtailment with and without DLRs.

Month	Curtailment with SLRs (GWh)	Curtailment with DLRs (GWh)	Change to Curtailment (%)
Jan	53	35	-35
Feb	23	17	-26
Mar	49	40	-19
Apr	58	46	-20
May	52	52	0
Jun	29	41	43
Jul	12	16	37
Aug	24	29	22
Sep	30	34	11
Oct	35	33	-6
Nov	32	26	-19
Dec	39	27	-29
Annual	434	395	-9

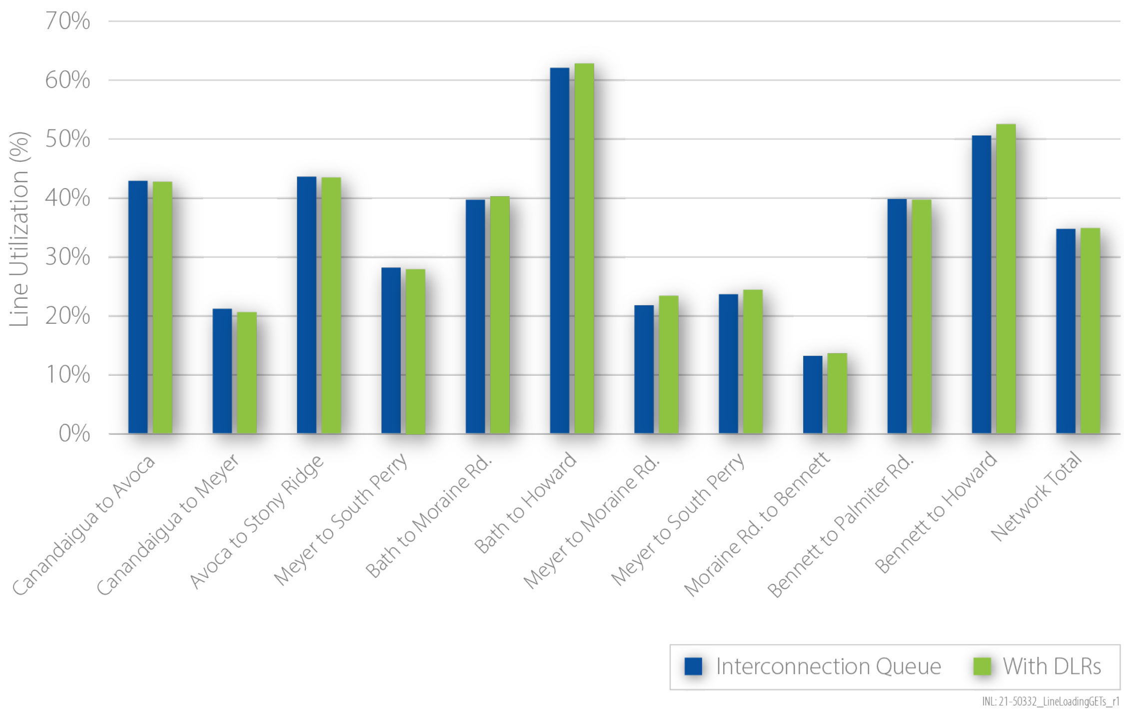


Figure 20. Line Loading for key lines in and around the Hornell and South Perry Transmission Zone.

By evaluating which contingencies are binding, it is clear the lines with a lower average rating using DLR versus SLR are seeing an increase in binding hours. The three main lines that experience increased hours binding with the introduction of DLRs are Eelpot to Flats (97% of static rating), Bennett to Palmiter (94% of static rating), and Palmiter to Andover (95% of static rating). This highlights that both the southwest and northeast flows out of the Hornell and South Perry Transmission Zone area are congested. It is also important to note that even before these lines' ratings were reduced by DLR, they had some of the lowest—if not the lowest—SLRs in the area.

It is important to note that this is just one case study evaluating DLRs. This instance showed minimal reduction to annual curtailment because, on average, DLRs decreased line ratings relative to the SLRs during the summer months when temperatures are higher and wind speeds are lower. This led to higher curtailment of solar resources during the summer months, but lower curtailment of wind resources the rest of the year. Despite mixed results on reducing curtailment, DLRs still provide system operators with greater insight into safe operations.

2.1.9 Simulation of Power Flow Controls

The Interconnection Queue case with increased wind and solar generation was also evaluated with the inclusion of PFCs. As discussed in Section 1, PFC devices are a set of technologies that redirect flows away from overloaded corridors and/or toward underutilized corridors within the existing transmission network. This allows power to be either "pushed" to limit flow, or "pulled" to increase flow across two lines with spare capacity. By balancing flows, transfer capacity is increased even after accounting for the loss of any one line.

In the grid modeling conducted for the case study, the PFCs were simulated in a *technology neutral manner.* While the assumptions were made to represent potential PFC capabilities, the input into the model was done by specifying angle limits associated with the PFC. Additional details on the PFC modeling methodology can be found in Appendix C.

For the purposes of this study, PFC control was modeled in a technology neutral way by changing line angles by +/-2 degrees, +/-4 degrees, and +/-8 degrees. This can be accomplished by incorporating additional PFC device and increased capital costs. In the case of DSSC, this represents additions of approximately 2–16 5-kV PFC devices for each line segment evaluated. However, the conversion from angles to other quantities, such as impedance, can be made to extend the results to other types of PFC technologies. The locations of the evaluated PFC devices are provided in Figure 21 and based on the N-1 contingency overloads identified in Section 2.1.7.

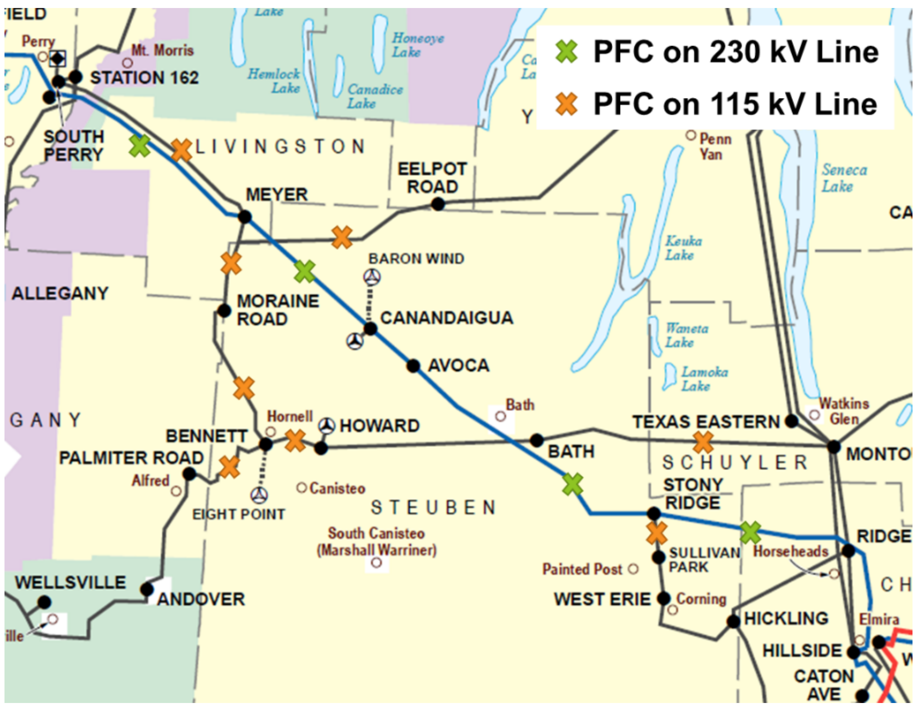


Figure 21. Locations of analyzed power flow control devices.

The resulting line loading, with and without PFCs included, is provided in Figure 22 and Table 14, respectively. The data highlights a large increase in line loading across the 230-kV system (e.g., the left-hand portion of the chart) and a more balanced loading across the 115-kV system. Overall, line loading increases across the network from 35% in the Interconnection Queue case (without PFCs) to 38–49% depending on the number of PFC devices deployed. The balancing of flows across the network allows for an increase in transmission flows, and thus, a decrease in curtailment throughout the renewable generation pocket.

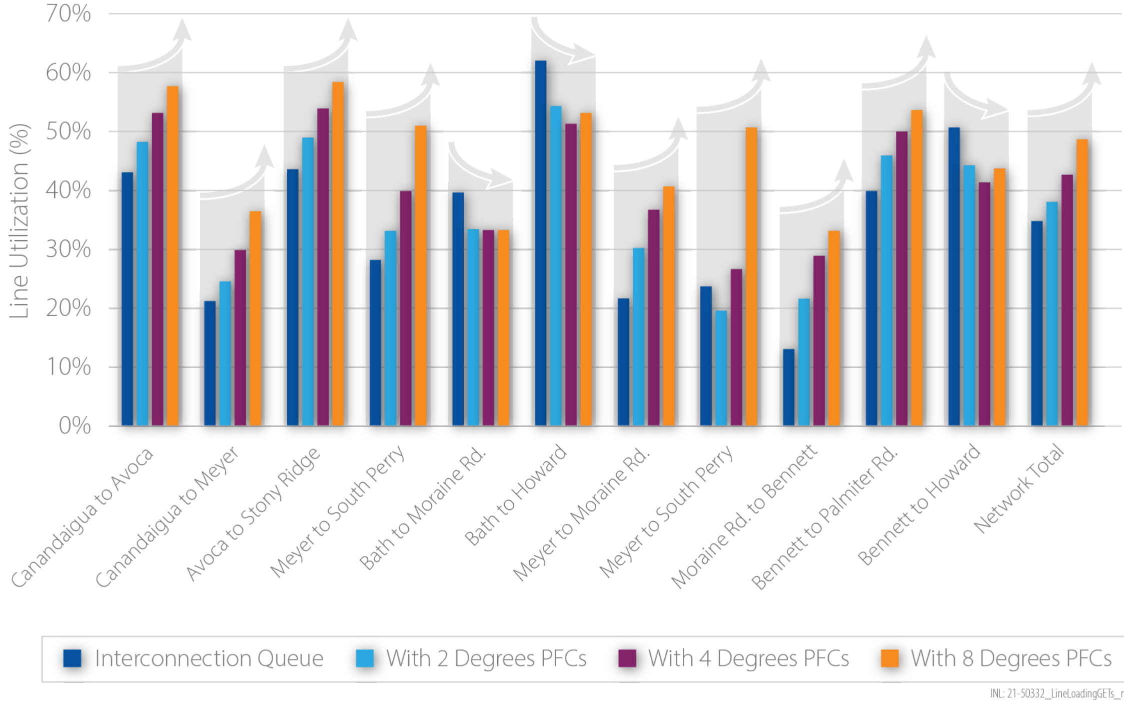


Figure 22. Annual line loading for selected lines in study region, with PFCs deployed.

Table 14. Selected line flows in study region, with PFCs deployed.

		Canandaigua to Avoca	Canandaigua to Meyer	Avoca to Stony Ridge	Meyer to South Perry	Bath to Moraine Rd.	Bath to Howard	Meyer to Moraine Rd.	Meyer to South Perry	Moraine Road to Bennett	Bennett to Palmiter Rd.	Bennett to Howard	Network Total
	Limit (MW)	498	498	498	430	124	124	125	82	125	78	124	
	Voltage (kV	230	230	230	230	115	115	115	115	115	115	115	
Base Case	Forward Flow (GWh)	896	37	927	7	140	1	228	6	166	38	190	
	Reverse Flow (GWh)	10	604	8	1029	14	348	0	126	1	112	11	
	Total Flow (GWh)	906	640	936	1036	154	349	229	133	166	149	201	4899
	Utilization	21%	15%	21%	28%	14%	32%	21%	18%	15%	22%	19%	21%
Interconnection Queue	Forward Flow (GWh)	1870	276	1904	175	430	0	94	94	79	97	549	
	Reverse Flow (GWh)	1	648	1	885	1	674	144	76	65	175	0	
	Total Flow (GWh)	1871	924	1904	1060	431	674	239	170	144	272	549	8237
	Utilization	43%	21%	44%	28%	40%	62%	22%	24%	13%	40%	51%	35%
With 2 Degree PFCs	Forward Flow (GWh)	2104	233	2137	221	358	0	55	111	43	104	481	
	Reverse Flow (GWh)	0	835	0	1026	4	591	276	30	193	211	1	
	Total Flow (GWh)	2104	1068	2138	1247	362	591	332	140	236	314	481	9013
	Utilization	48%	24%	49%	33%	33%	54%	30%	20%	22%	46%	44%	38%
With 4 Degree PFCs	Forward Flow (GWh)	2319	246	2352	298	338	5	68	141	58	127	444	
	Reverse Flow (GWh)	0	1063	0	1209	23	552	335	50	258	215	7	
	Total Flow (GWh)	2319	1309	2353	1507	361	557	403	191	317	341	450	10109
	Utilization	53%	30%	54%	40%	33%	51%	37%	27%	29%	50%	41%	43%
With 8 Degree PFCs	Forward Flow (GWh)	2516	289	2549	457	304	23	104	215	94	163	448	
	Reverse Flow (GWh)	0	1302	0	1466	58	553	341	149	268	203	27	
	Total Flow (GWh)	2516	1591	2550	1924	362	576	445	364	362	366	475	11531
	Utilization	58%	36%	58%	51%	33%	53%	41%	51%	33%	54%	44%	49%

Additional figures are provided to better understand the changes in line flows occurring across the network due to the additions of PFCs. First, Figure 23 shows the same hourly flow duration curves for three selected line segments. It shows that with the PFCs enabled to the Interconnection Queue case, flows increase at all hours across the Canandaigua to Avoca 230-kV line segment and allows the line to reach its thermal rating across more hours of the year. The Bath to Howard 115-kV segment sees a reversal of flow during some hours with the PFCs incorporated, and more balanced flows generally. The same is true for the Bennett to Howard line, which increases its flow in the reverse direction (e.g., Howard to Bennett) during most hours, but also sees an increase in flow in the forward direction in others. This highlights the flexibility afforded to the PFC-enabled lines, which can more easily balance flows across the network due to changes in wind and solar generation.

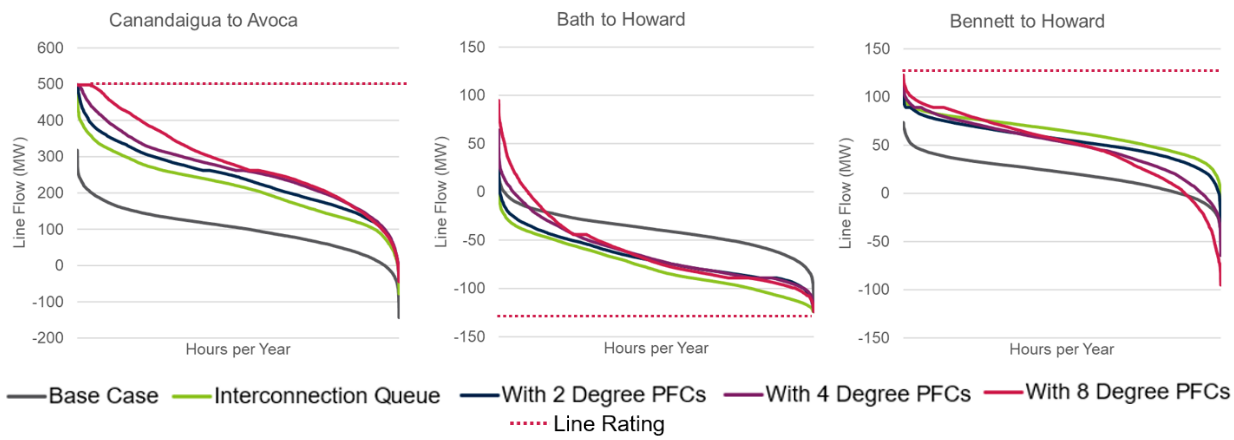


Figure 23. Line flow duration curves for selected line segments, with PFCs deployed.

Figure 24 shows the average annual angle, in degrees, for the PFC devices at each line segment. This shows that, in general, the PFC set points are near their minimum/maximum angle and highlights the line segments that change their loading the most based on the total angle change. For example, the 230-kV segments from Avoca to Stony Ridge see the largest change in angle set points across the entire year. As discussed earlier, positive line flow is in the direction from the first point in the line segment to the second point. The first chart on the left shows that line flow is almost always flowing from Canandaigua to Avoca, while the second chart shows that much of the time the line flow is actually flowing from Howard to Bath.

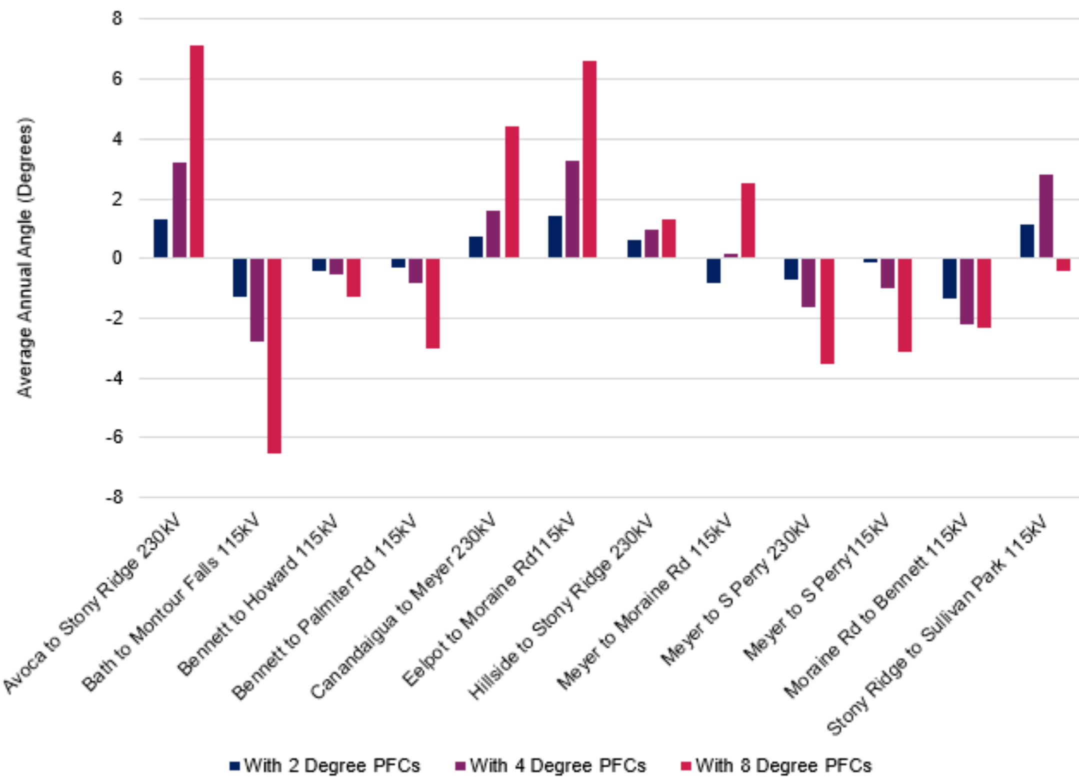


Figure 24. Average annual PFC angle set point by line segment.

The resulting change to wind and solar curtailment in the Hornell and South Perry Transmission Zone is provided in Table 15 for the cases with and without PFCs. The data from this table shows that PFCs can successfully decrease wind and solar curtailment from 15% of available energy without transmission upgrades or other GETs, and down to 8% with PFCs deployed with up to an 8-degree change in line angle. Benefits of PFCs can be found in production costs, avoided emissions, and avoided transmission system and renewable generation buildout.

Table 15. Summary data for the total renewable energy in the Hornell and South Perry Transmission Zone: Interconnection Queue versus with PFCs.

	Interconnection Queue	With 2 Degree PFCs	With 4 Degree PFCs	With 8 Degree PFCs
Total W&S Available (GWh)	2,980	2,980	2,980	2,980
Total W&S Generation (GWh)	2,545	2,643	2,689	2,734
Total W&S Curtailment (GWh)	434	336	291	246
Total W&S Curtailment (%)	15	11	10	8
Avoided Curtailment (GWh)*	-	98	144	188
Avoided Curtailment (%)*	-	23	33	43

* Relative to Interconnection Queue

The deployment of PFCs within the Hornell to South Perry Transmission Zone result in clear benefits to both system flexibility and the reduction of curtailment. All PFCs evaluated showed significant reductions in curtailment, ranging from 23–43%. Additionally, PFCs enabled existing transmission lines to be used more efficiently, as shown in Figure 22. The utilization of several line segments more than doubled with PFCs versus the Interconnection Queue case.

An additional scenario was evaluated that combined both the “With 4 Degree PFCs” and “With DLRs” cases discussed above. This scenario included all 12 PFCs, as outlined in Figure 21, and implemented DLRs across all 16 lines identified in Figure 17. This scenario evaluated the full buildout of GETs options that until now have been evaluated in isolation.

Results showed that the impact of combining these two technologies led to improvements that roughly equaled the sum of the gains achieved by just using these technologies in isolation. As shown in Table 15, the scenario with 4 Degree PFCs and DLRs combined experienced a reduction in curtailment within the Hornell and South Perry Transmission Zone of 182 GWh, just shy of 184 GWh, which is the sum of the reduction achieved with DLRs (40 GWh) and with 4 Degree PFCs(144 GWh), respectively.

The ability for these two technologies to be used together and achieve nearly the sum of their parts highlights their complementary nature. Instead of having overlapping gains, the results of this scenario support that each technology provides unique value to the system and the technologies can be used in conjunction with one another, as shown in Table 16.

Table 16. Annual renewable generation and curtailment across incremental GETs cases.

	Interconnection Queue	With DLRs	With 4 Degree PFCs	With 4 Degree PFCs & DLRs
Total W&S Available (GWh)	2,980	2,980	2,980	2,980
Total W&S Generation (GWh)	2,545	2,585	2,689	2,727
Total W&S Curtailment (GWh)	434	395	291	253
Total W&S Curtailment (%)	15	13	10	8
Avoided Curtailment (GWh)*	-	40	144	182
Avoided Curtailment (%)*	-	9	33	42

* Relative to Interconnection Queue

2.1.10 Summary and Case Comparisons

The results presented thus far quantify and illustrate the benefits of GETs to reduce renewable curtailment and congestion, as well as to reduce production cost. Both ultimately lead to ratepayer savings. This section summarizes the findings across all cases evaluated in a consistent manner to allow for direct comparison between cases with and without GETs, as well as those with conventional transmission upgrades.

For the purposes of this analysis, the reduction in wind and solar curtailment is used as the primary benefit of GETs. It can be used as a proxy for avoided or deferred conventional transmission upgrades and lower cost to achieve the state’s 70% renewable energy by 2030 clean energy standard.

In general, the ability to increase wind and solar generation in the Hornell and South Perry Transmission Zone, without adding conventional transmission upgrades, means that additional renewables are not required in other regions of the state, thereby deferring the operating and capital cost of meeting renewable targets.

A summary of the annual wind and solar generation, curtailment, and avoided curtailment (e.g., relative to the Interconnection Queue reference case) are provided in Table 17 across the nine evaluated cases. The avoided curtailment ranges from 98 GWh/year in the PFC case with the +/-2-degree angle changes to 188 GWh/year in the PFC +/-8-degree angle changes. This represents a 23–43% reduction in curtailment without including conventional transmission upgrades.

Table 17. Summary wind and solar generation and curtailment data by scenario.

	Total W&S Available (GWh)	Total W&S Generation (GWh)	Total W&S Curtailment (GWh)	Total W&S Curtailment (%)	Avoided Curtailment (GWh)*	Avoided Curtailment (%)*	Annual Curtailment Savings (k$)**
Base Case	513	513	0	0	-	-	-
Interconnection Queue	2,980	2,545	434	15	-	-	-
With 2 Degree PFCs	2,980	2,643	336	11	98	23	4,221
With 4 Degree PFCs	2,980	2,689	291	10	144	33	6,189
With 8 Degree PFCs	2,980	2,734	246	8	188	43	8,103
With DLRs	2,980	2,585	395	13	40	9	1,717
With 4 Degree PFCs & DLRs	2,980	2,727	253	8	182	42	7,814
With Traditional Upgrades	2,980	2,862	118	4	316	73	13,597
With GETs and New Substation	2,980	2,758	222	7	212	49	9,115

*Relative to Interconnection Queue Scenario
**Savings from Avoided Curtailment using $43/MWh LCOE, Relative to Interconnection Queue Scenario

A case was also evaluated with additional proposed conventional upgrades. These upgrades were based on proposals by the TO and a review of overloads where wind and solar generation is added to the transmission network. In the traditional transmission upgrades scenario, the 115-kV network was reconductored, the 230-kV segment from Meyer to South Perry was reconductored, and the 115-kV Bath substation was tied into the 230-kV line from Avoca to Stony Ridge connecting the 115-kV loop to the 230-kV backbone in the southeast region of the study footprint. This case resulted in the largest reduction in curtailment of -73%, but also comes at a higher cost.

Another case was also evaluated that combined aspects of both the “With 4 Degrees PFCs and DLRs” case with elements of the “With Traditional Upgrades” case; namely, the 115-kV Bath substation tied into the 230-kV line from Avoca to Stony Ridge. This case is referred to as "With GETs and New Substation." Although this case does not match the curtailment reductions from the "With Traditional Upgrades" case, it comes close with a 49% reduction and much lower costs.

To quantify the avoided wind and solar curtailment into economic terms and ultimately ratepayer savings, the study assumed a simple levelized cost of energy ($/MWh) for wind and solar resources. Levelized cost of energy (LCOE) was used on the assumption that if curtailment were not reduced, additional renewables would need to be added to meet the State of New York's clean energy standard. Therefore, the avoided curtailment is translated to avoided capital cost of new wind and solar technologies. The value used in this analysis was $43/MWh and represents a generation-weighted LCOE for the assumed solar and wind resource additions located in the region and was based on National Renewable Energy Laboratory (NREL) Annual Technology Baseline estimates for the year 2025 for wind and solar technologies [40].

LCOE of wind and solar was used as the primary economic metric, in place of production cost savings, to avoid double counting the avoided cost of reduced natural gas consumption and imports and the avoided capital cost of new generation to meet policy goals. In addition, it does not explicitly account for avoided transmission costs, because it allows for conventional transmission upgrades to be compared directly against GETs. The results of this analysis are provided in Table 18, which quantifies the savings attributed to avoided curtailment for each scenario relative to the Interconnection Queue scenario with no GETs or conventional transmission upgrades. The savings range from $1.7 million with the DLR to $8.1 million per year, depending on the GETs scenario evaluated, and $13.6 million with the traditional upgrades. However, these values do not include the cost of building GETs or transmission upgrades, which are evaluated in the following section for a benefit-cost analysis. While the traditional upgrades yield higher curtailment reductions, they are more expensive and take longer to deploy. As a result, because GETs deployment reduces some but not all curtailment, it may be the most efficient use of ratepayer funds.

Table 18. Summary of Exports and Imports across NYISO, including Net Import Costs and Savings versus the Interconnection Queue case.

	Net Generation (GWh)		Net Revenue (k$)		Total Net Imports (GWh)	Total Net Imports Cost (k$)	Avoided Net Imports (GWh)*	Avoided Net Imports Cost (k$)*
	EXPORTS	IMPORTS	EXPORTS	IMPORTS				
Base Case	-4,205	31,649	-79,092	744,448	27,444	665,356	NA	NA
Interconnection Queue	-4,513	27,895	-87,085	480,352	23,382	393,267	NA	NA
With 2 Degree PFCs	-4,513	27,768	-87,241	479,248	23,255	392,007	127	1,260
With 4 Degree PFCs	-4,513	27,739	-87,213	479,395	23,227	392,182	155	1,085
With 8 Degree PFCs	-4,512	27,713	-87,611	479,027	23,200	391,416	181	1,851
With DLRs	-4,513	27,891	-87,527	478,520	23,378	390,994	4	2,273
With 4 Degree PFCs & DLRs	-4,512	27,711	-87,212	477,840	23,199	390,628	183	2,639
With Traditional Upgrades	-4,515	27,594	-89,784	479,274	23,079	389,490	345	4,374
With GETs and New Substation	-4,514	27,735	-89,543	482,429	23,220	392,886	203	978

*Relative to Interconnection Queue Scenario

As discussed above, Avoided Curtailment Savings using the LCOE of wind and solar is the primary economic metric as it accounts for a wide range of benefits. Another area of benefits, albeit smaller, is the impact to NYISO's net imports, as shown in Table 19. If using production cost as a metric, which includes only costs of in-state resources, avoided import cost must also be included. These savings, ranging from about $1 million to almost $4.4 million per year, highlight the impact of how reducing congestion in the Hornell and South Perry Transmission Zone impacts net imports across the entire system. It is important to note that a change in net imports on a GWh basis does not always translate into the same level of cost savings. This is due to the timing of those imports. A certain technology, such as in the With DLRs case, may reduce net imports by only 4 GWh versus the Interconnection Queue case, but it also allows all remaining net imports to be managed more efficiently. This can lead to reducing the amount of high-cost imports and increasing the amount of exports during opportune times.

Table 19. Summary of annual savings across production cost, net imports and avoided curtailment across all scenarios.

	Production Cost Savings (k$)*	Net Imports Savings (k$)*	Avoided Curtailment Savings (k$)**
Interconnection Queue	NA	NA	NA
With 2 Degree PFCs	1,704	1,260	4,221
With 4 Degree PFCs	2,854	1,085	6,189
With 8 Degree PFCs	4,586	1,851	8,103
With DLRs	113	2,273	1,717
With 4 Degree PFCs & DLRs	3,214	2,639	7,814
With Traditional Upgrades	2,479	4,374	13,597
With GETs and New Substation	4,008	978	9,115

*Relative to Interconnection Queue Scenario
**Savings from Avoided Curtailment using $43/MWh LCOE, Relative to Interconnection Queue Scenario

In addition, the results indicate that GETs can be a beneficial intermediate operating point, where wind and solar is added to the system, while longer-term transmission upgrades can be planned and deployed. Ultimately, new transmission will be required to reach the high levels of renewable generation planned for in the State of New York's 70% by 2030 clean energy plans. GETs can be a key enabler to that transition and reduce and defer (but not eliminate) the need for new transmission. A similar finding in other regions is likely.

Finally, several benefits were not quantified by this study. For example, reduced curtailment also displaces fossil fuel generation and the associated CO_2 emission and other environmental pollutants. While this may not directly translate to monetary ratepayer benefits, it does have benefits for human health and global climate change. In addition, DLR was not shown to have significant curtailment and monetary benefits in this analysis because the summer ratings dropped below existing static ratings. However, this does yield reliability benefits for consumers as well because the lines are operated at more appropriate levels given ambient conditions, thus avoided equipment degradation and potential safety risks of transmission overloads. These additional benefits are discussed in the following section.

2.2 Valuing GETs and Impact to Ratepayers

Assessing the value of GETs systems can be complicated. Because of the interconnected nature of the electric power system, implementing GETs to alleviate congestion on a line or group of lines may move congestion downstream to other connected lines, limiting the effectiveness of the GETs solution. Ambient conditions could also vary along different spans of a long transmission line. If the DLR system does not cover the limiting span of the transmission line, values calculated using DLR could overstate the safe ampacity rating of the line and downstream equipment ratings could become the most limiting element. In addition, the assessment of DLRs may need to factor in the incremental value of DLR over AAR. The addressable market for GETs is often framed with respect to the total congestion costs in a system, but GETs can only offset a fraction of those costs. However, as outlined in Table 20, additional benefits associated with GETS exist. Some are readily quantifiable as demonstrated within this report, while others assist in the effective operation of the power system.

Table 20. Summary of key GETs benefits.

Benefit Type	Description	Quantification Methodology
Reduced congestion via operational flexibility	GETs can increase available transmission capacity and improve operational efficiencies by reducing production costs, congestion costs, renewable generation curtailments, and reserve requirements. Higher ratings also mitigate the impact of contingences, such as generation or transmission system outages.	See Section 2.1
Asset deferral	By unlocking unused transmission capacity, GETs can defer capital expenditure for system upgrades and serve as an important bridge source of transmission capacity while longer-term solutions are implemented.	See Section 2.2.2
Renewable integration	GETs facilitate renewable integration by reducing the extent of system upgrades required to interconnect and dispatch the new generation sources.	See Table 16
Situational awareness	DLR provides more accurate line condition information to improve operators' decision-making. While primarily useful for safe real-time operations, the situational awareness provided by sensor-based DLR solutions can also be used to infer icing conditions on the power line and useful in detecting wildfire conditions that affect local line rating parameters and endanger the public.	Risk Assessment Methods
Resilience and Contingency Support	DLRs are generally more accurate than ratings calculated using current methods. This enhances system resilience by reducing or avoiding transmission overloads that reduce the service life of transmission lines or cause outages due to faults from excessive sagging of lines. The flexibility afforded by GETs—in general—and the control enabled by PFCs—in particular—are useful in contingency and short-duration emergency conditions as the system is stressed.	Risk Assessment Methods
Asset health monitoring	The acquisition and analysis of DLR information supports the assessment of line condition and the development of predictive and preventive maintenance measures for the line.	Risk Mitigation Methods

Section 2.2.3 discusses the quantification and interdependence of the first three items on the list in Table 20. Cost effectiveness—in light of congestion relief, renewables integration, and transmission deferral—is assessed relative to traditional grid upgrades. However, examining only those benefits misses much of the value of DLR and DTR in that both aim to capture field conditions more accurately. Dynamic ratings that do not focus on congestion mitigation may be

challenging to quantify, but these value streams should be considered in the evaluation of DLR and DTR investments. First, as utilities transition to a modern grid infrastructure, these investments could be seen as risk mitigation strategies by providing more insights on multiple levels of grid operation. Risk mitigation methodologies are well-established in the industry and include evaluations of the likelihood of a given incident, the outcome of the investment on avoiding that incident, and the consequence of the incident should it occur.

In short, congestion mitigation is a useful and important component of the overall value proposition for GETs investments. However, the additional values articulated below may unlock additional capabilities that do not directly affect the cost of power in the near-term but can improve the long-term operation of the bulk-power system.

2.2.1 The GETs Benefits of Mitigating Risks

Recent GETs value assessment case studies have not explicitly assessed the benefits associated with asset health monitoring, situational awareness, or general public safety. The simple reason these more difficult-to-quantify benefits are not usually addressed is that the avoided congestion costs alone typically result in a positive benefit-cost ratio (as seen in a recent PJM study, for example) [22]. Nevertheless, it is important to consider all potential values in assessing GETs deployments.

GETs provide needed system flexibility for renewable energy transition: Each of the GETs outlined in this document addresses the need for a more dynamic transmission system that can support an increasingly renewable and distributed generation mix. The ultimate intent of these technologies is to operate the system more effectively. The next generation distribution system platform (DSPx) initiative’s Decision Guide Volume III articulated a cost-effectiveness framework for distribution investments that included a category of expenditures related to supporting public policy and societal benefits (such as enabling a greater mix of renewable generation) [41]. This investment category has been used by multiple-state public utility commissions as they explore distribution investments. FERC is currently considering updates to its transmission incentives policy for modernized and risk-reducing investments, while DOE has made funding available to “support innovative transmission projects” aimed at projects supporting clean energy [42] [43].

DLR systems support public safety: Consideration of the public safety benefit is inherent in the way all utilities do business. Prudent asset health monitoring and situational awareness are both methods of protecting the public from dangerous conditions, while also ensuring the performance of investments. More explicitly related to public safety, DLR sensors and analytics monitor the clearance of transmission lines from the ground or nearby vegetation. Without sufficient clearance, electricity traveling on the power line can cause sparks, which can lead to fires.[e] DLR systems alone cannot avoid wildfires, but they are part of a broader solution that can

[e] The California PUC's Safety and Enforcement Division (SED) report on the Camp Fire showed that electric power lines sparked the deadly fire: cdn.cnn.com/cnn/2019/images/12/03/i1906015.appendix.a.sed.camp.fire.investigation.report.redacted.pdf

provide the data to assist in wildfire prevention strategies, including how to operate the grid, when to clear vegetation, and when to upgrade equipment.

DLR and DTR systems provide proactive asset health monitoring: Maintenance schedules have traditionally been based on standard time increments or as necessitated by system expansion. With load growth slowing across the Nation, utilities are adopting a big data approach to asset monitoring, opting for a proactive just-in-time replacement rather than a reactive approach. This proactive approach helps to replace assets before they fail, improving reliability and keeping electric power flowing to customers who rely upon it. As outlined in Appendix A, DLR and DTR sensor technologies provide greater insight into the performance of assets over time by monitoring the characteristics of the assets. This data can then be mined to better maintain the performance of aging infrastructure. Rather than relying on periodic manual inspections, sensors combined with data analysis can continually monitor the grid and detect anomalies and deliver real-time alerts when conditions are observed that indicate risk to grid reliability or public safety.

DLR and DTR systems improve situational awareness: A major contributing factor to premature asset failure is when operational practices misalign with planning assumptions. By keeping a closer eye on the conditions of field equipment, operators are better informed about their system performance relative to planning assumptions. Moreover, DLR/DTR schemes give system operators a more complete picture of how the system is performing, particularly in contingency situations. This greater insight allows for operators to maximize their system's performance while maintaining a safe, reliable, and efficient system.

Costs were established for each GETs scenario, as well as the traditional upgrades case. Costs for the traditional upgrades case were sourced from a variety of publicly available cost estimation guides, notably the MISO's Transmission Cost Estimation Guide, which includes costs for building new transmission, reconductoring existing transmission, new transformers, and other substation equipment [44] [45] [46]. The traditional upgrades cost includes reconductoring of most of the lines in the region to a higher rated conductor, replacing transformers with higher rated equipment, and adding a new 230/115 substation, which has the benefit of providing flexibility and additional contingency support. Total costs for upgrades to the section were $205.5 million as estimated by the transmission operator [46].

Literature for GETs was limited in cost estimation guides. DLR costs were assembled using a recent PJM study completed with vendor input and a 2014 DLR economic study assessing the 130 kV system in western Hornell and South Perry Transmission Zone [22] [47]. Each of the DLR sources roughly aligned on costs despite one providing a per-mile, and the other a per-line estimation framework. PFC costs vary widely in literature and appear to be a function of the rated size, complexity of the installation, specific device functionality under consideration, and necessary control systems at the system operator. A range of costs were used because of the wide variance in PFC costs, roughly aligning with the data presented in several sources [48] [49] [50] [51].

Cost estimation guides for GETs should be developed with input from the vendor community; the costs reflected herein likely oversimplify the initial integration and engineering, the communication systems required, and any ongoing O&M costs. Such a guide would help to ensure that GETs are assessed using appropriate assumptions across the country.

2.2.2 Assessing Multi-Value Options

Analyzing the results of the production cost modeling provides a multitude of potential benefits to assess. The benefits of additional renewable integration avoided renewable curtailment for existing resources, and a lowered production cost do not stack; one cannot simply add their value together. Instead, these benefits are lenses through which we can evaluate transmission project options. Other lenses may include enhanced system flexibility, avoided investment in capacity generation, reduced ancillary service requirements, reduced transmission losses, and deferred transmission build-out.

For the case study region where the system is required to reach 70% renewable generation by 2030, the annual value of the avoided renewable energy curtailment is a valuable metric. Renewable energy is a primary driver for transmission upgrades in this region. Using the 2020 NREL Annual Technology Baseline Data, the generation-weighted LCOE is $43/MWh for the mix of wind and solar in the interconnection queue [52]. By applying that LCOE to the renewable energy curtailment avoided, we are able to find an annual value of the renewable energy curtailment avoided. These findings are presented in Figure 25. Again, the curtailment that was avoided in this region represents generation that would have been built elsewhere to meet policy goals.

Figure 25 shows the uncertainty of the costs with respect to GETs strategies, represented by the length of the boxes along the y-axis. More accurate costs would have an impact on the ultimate solution selected. The general trend here is that the GETs strategies inch toward the Traditional Upgrades case with respect to renewable energy curtailment avoided, but at a lower cost. The portfolio of GETs strategies provide optionality for system planners to improve the performance of the system. While only the energy value of the renewable energy curtailment is assessed here, similar trends are present for other system economic metrics, such as annual production cost for the state, and net import costs.

Given the granularity of the case study and the simplification used to display these graphics, caution should be used in evaluating the efficacy of GETs scenarios relative to one another. Different scenarios will have different considerations, depending on existing system topology, geography, and future scenarios under consideration. However, the broad takeaway from the analysis is relatively straightforward: GETs seem to provide a significant portion of the benefits provided by traditional upgrades at a fraction of the cost.

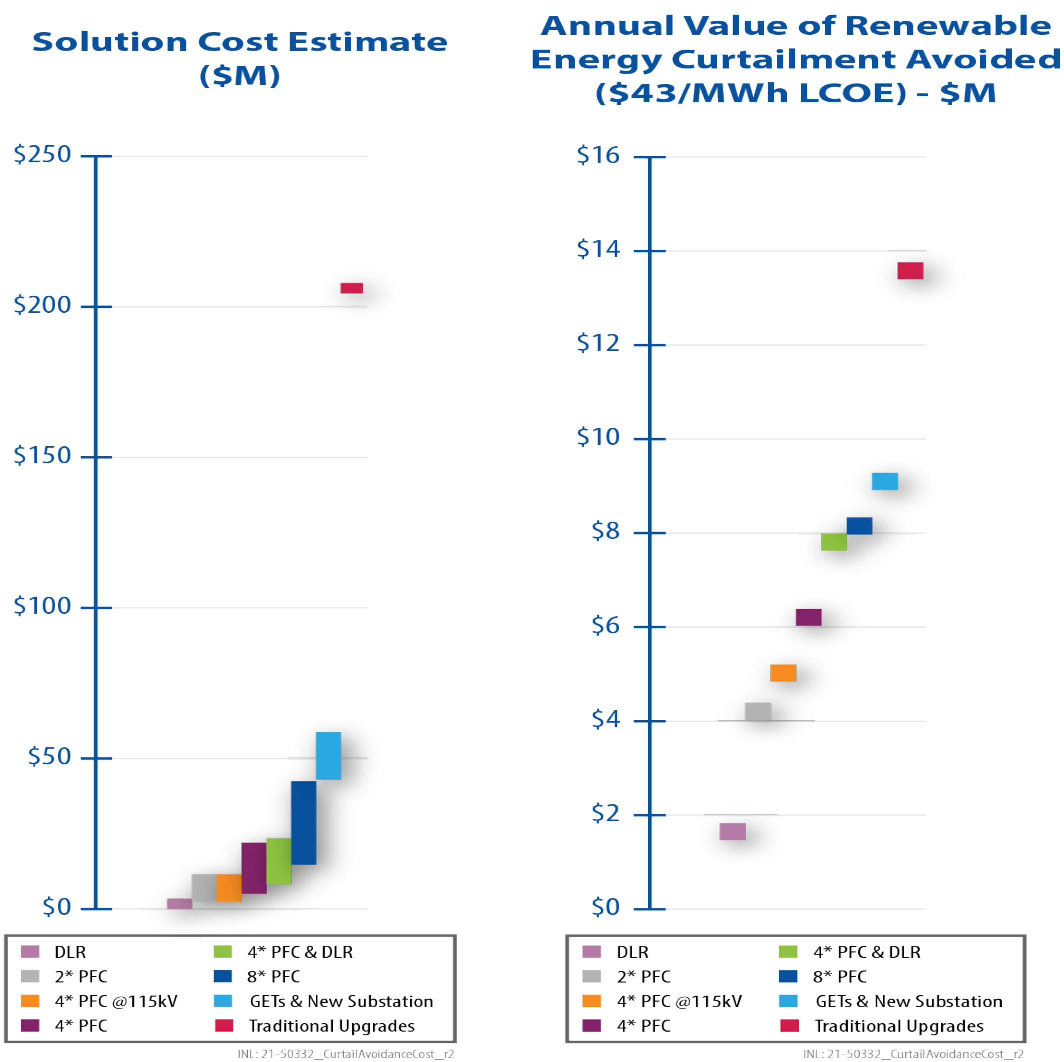


Figure 25. Solution cost estimates relative to the annual value of the renewable energy curtailment avoided.

Extending this analysis one step further, Figure 26 outlines the payback period for each solution, providing the range of potential payback periods based on the costs of the proposed solution. Note that this analysis does not include any O&M considerations for either GETs or Traditional Upgrades, but merely divides the estimated costs by the annual energy value. To be sure, this analysis oversimplifies the value of energy in a market construct, but indicates that GETs strategies pay for themselves more quickly than traditional alternatives. However, these technologies are not necessarily direct substitutes to one another. Instead, GETs can be used to defer or delay the need for conventional transmission upgrades, but the least cost options in the long run are likely a combination of GETs and traditional upgrades. While GETs are expected to have shorter lifecycles – sensors and software packages often need to be refreshed every 10-15 years as opposed to the decades long lifecycles associated with new lines and transformers – the economics seem to minimize the risk of stranded, undepreciated, but unneeded assets.

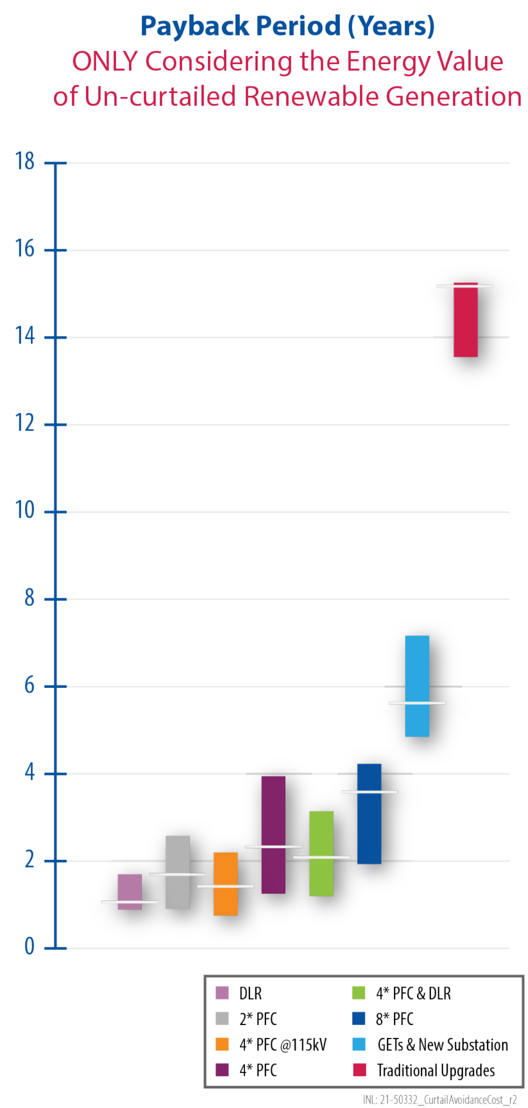


Figure 26. Payback Period for Each Solution Based Only on Uncurtailed Renewable Generation.

GETs do not provide all of the value of traditional upgrades or new transmission buildout in the near term, and do not necessarily provide the same proportion of benefits as future scenarios are considered and the bulk-power system evolves over the coming decades. Further, transmission planning is often oriented around a risk mitigation framework and the traditional upgrades represent a risk minimization for dealing with power system uncertainties. With respect to uncertainties, this analysis does not consider the ancillary services required to rely upon DLRs or a variable and uncertain generation portfolio. That is, relying upon predicted DLRs in dispatching generation may introduce another uncertainty and require additional regulating reserve generation to meet the real-time needs of the grid. The tools used here attempt to optimize the system across each hour of the year based on input parameters, but do not consider intra-hour deviations, forecast accuracy, transmission outages (every transmission element is assumed 100% available all the time), nor any fixed O&M cost of increased generation cycling that may be required as ancillary services.

To be clear, the stability of the power system and localized resource capabilities required for greater renewable energy interconnection should be studied. However, the methodology used herein is consistent with NYISO's 2019 CARIS report, which analyzes the potential costs and benefits of mitigating congestion using generic transmission, generation, demand response, and energy efficiency solutions, but does not capture the sub-hourly variation in renewable generation. The CARIS report also outlines that the renewable curtailment seen in NY is a function of transmission constraints, rather than system stability considerations.

The results of the study suggest that GETs are a significantly more affordable option to integrate *some* additional new generation. Transmission projects take 5-10 years to plan, develop, and construct [53]. GETs take some time to plan, develop, and construct, but appear to pay for themselves in under 10 years. The results of this study suggest that GETs could prove cost-beneficial in avoiding renewable generation curtailment in the short term and remain useful to facilitate the interconnection of future generation resources while also providing situational awareness and flexibility resources in the longer term.

2.2.3 Translate to Ratepayers

Translating cost savings to ratepayers is an indirect exercise. Even if detailed costs for GETs were readily available, a ratepayer impact assessment would need to consider the various depreciation timelines associated with GETs, the combination of hardware and software required to successfully implement a GETs scheme, and the incremental O&M necessary to ensure hardware/software/cybersecurity functionality and maintain integrations with other grid operational systems. A ratepayer bill impact assessment would further need to consider how traditional and GETs system upgrades would layer upon planned utility upgrades throughout the organization, potentially competing with other system upgrades (transmission or otherwise) for ratepayer dollars. Given that these technologies primarily operate at the bulk-system level, there are further bilateral contract, transmission charges, and cost allocation implications. Layering on top of these complex accounting principles are considerations for public policy. Modern grid planning does not necessarily require selection of cost-beneficial solutions; rather, planners evaluate cost-effectiveness considering a variety of values, ultimately selecting the solutions that meet the stated need at the lowest reasonable cost. Effectively, assessing the impact on the ratepayer cannot be performed in isolation. Figure 27 below illustrates this complexity.

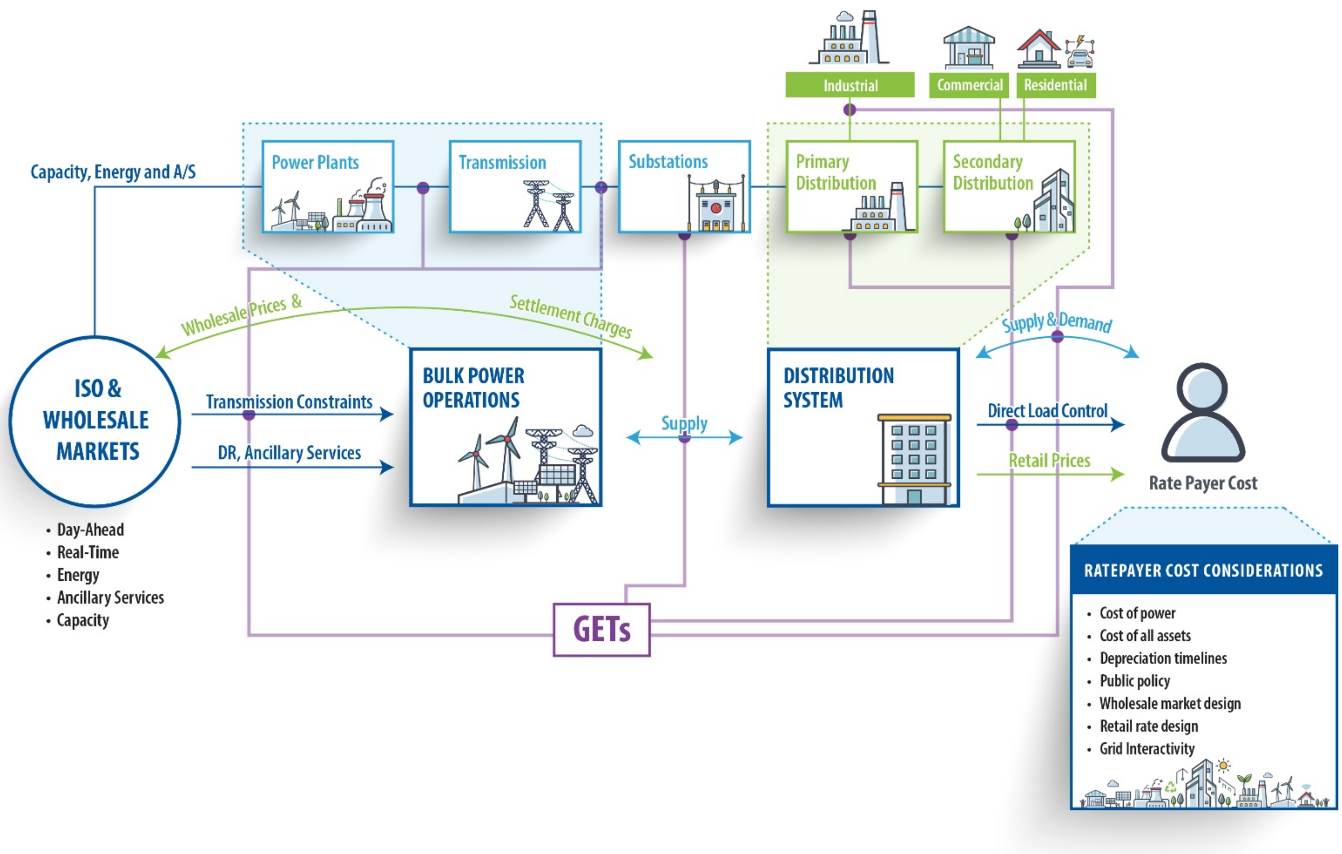


Figure 27. Ratepayer Cost Considerations

There is a further complication of the localized nature of the study and the cost allocation. Given the tangential impacts felt in other parts of the state associated with alleviating transmission constraints in this region, there is a case to be made that these impacts should be shared across each of New York's 8.4 million electric customers [54]. However, given the multitude of uncertainties across the state, there is a case that impacts should be attributed to the 450,000 people who live in Steuben and neighboring counties [56]. Finally, given that the utility would be creating value for its customers, a case can be made to spread the impacts across each of the 900,000 customers served by the utility provider in this region. The case for and against each of these cost allocation methodologies is captured in Table 21 below.

Table 21. Reasons for and against cost allocation spread across various sets of ratepayers.

Spread Across	Reasons *for* this Method	Reasons *against* this Method
New York (9.8M customers)	• Impacts of GETs can be seen across the state	• Impacts of GETs minimal outside of region
Utility (900,000 customers)	• Innovative value creation should serve customers of responsible entity	• Bulk system is interconnected • Utility has multiple non-adjacent service territories within state
7 county region (450,000 people)	• Local value of GETs stays with local population	• Why stop at neighboring counties? • Value outsized relative to the energy needs of this region

INL: 21-50332_Translating-benefits_r1

However, given the language inspiring this study and the need to translate the scale of the investments and benefits quantification to a general audience, a discussion of impact on ratepayer is included below. Performing this analysis glosses over many of the benefits of GETs discussed above.

The study methodology readily provides a one-year look at production cost savings, net import savings, and the value of avoiding renewable energy curtailment. The one-year look is useful in evaluating GETs impact across each hour of the year but does not provide insight on multi-year transition plans to assist in meeting the state's renewable energy targets. GETs are often seen as a bridge to assist in integrating new generation while longer-term transmission solutions are developed. Still, these "bridges" will remain in use beyond the one year that has been evaluated in this study and translating these one-year figures across the lifetime of the assets without accounting for other market and grid changes is problematic. More simply, the market will perform differently in 2030 as New York continues to integrate more renewable energy; it is inaccurate to claim the benefits that were modeled in this case study will remain as the market shifts over the decade. However, the flexibility and situational awareness afforded by GETs will likely remain useful tools for grid operators.

Throughout this section, an annualized cost of each solution is utilized. For each GETs strategy, a 12-year straight depreciation of initial cost and $250,000 ongoing O&M cost was assumed in an attempt to capture ongoing licensing and upkeep costs. For traditional upgrades, a 30-year straight depreciation of initial cost was assumed. As is discussed in Section 3.4, policy guidance is needed on the accounting treatment of GETs. However, the relatively shorter depreciation timelines associated with advanced metering infrastructure (rather than traditional mechanical metering) provided an example upon which GETs and traditional upgrade assumptions could be built.

Production Cost & Net Import Savings

The production cost savings associated with each of the scenarios can be compared with an annualized cost of the solution. As shown in Table 22 below, in some cases, the annualized cost of the solution is lower than the production cost savings simulated in one year. In cases where the numbers are negative (represented by parentheticals and greyed boxes), the savings from the more economic generation dispatch alone does not pay for the cost of the solution. The numbers indicate the annual savings (cost) net of the annual cost for the solution. Regardless of the solution, these figures should not be evaluated in isolation.

Table 22. Annual savings (cost) per set of ratepayers only considering production cost savings net of solution cost.[f]

Annual Savings (Cost) Per Set of Ratepayers ONLY Considering: Production Costs	2 Degree PFCs	4 Degree PFCs	4 Degree PFCs on 115 kV	8 Degree PFCs	DLRs	4 Degree PFCs & DLRs	Traditional Upgrade	GETs & New Substation
Annual Cost of Solution ($M)	$0.84	$1.44	$0.84	$2.62	$0.40	$1.59	$6.85	$2.76
Production Cost Savings ($M)	$1.70	$2.85	$1.21	$4.59	$0.11	$3.21	$2.48	$4.01
NY Electric Customer	$0.09	$0.15	$0.04	$0.20	$(0.03)	$0.17	$(0.45)	$0.13
Utility Customer	$0.95	$1.57	$0.40	$2.17	$(0.32)	$1.80	$(4.84)	$1.39
Person in 7 County Region	$1.90	$3.12	$0.80	$4.33	$(0.64)	$3.58	$(9.63)	$2.76

INL: 21-50332_CostSavingsTechStrat_r2

In addition to production cost savings, each of the scenarios adjusted the amount and time of imported generation into the State of New York. Similar to the production cost savings, net import savings should be considered in the evaluation of GETs and traditional upgrades. Table 23 shows the annual savings cost per set of ratepayers ONLY considering net import cost savings.

[f] Note that the per person impacts are effectively one-time payments (costs) made annually; the 2-degree PFC case would give each person in the 7 County Region almost $2 per year. Note that each of the dollar figures in these tables captured in parentheses [e.g., ($0.04)] represent increased costs to customers.

Table 23. Annual savings (cost) per set of ratepayers ONLY considering net import cost savings net of solution cost.

Annual Savings (Cost) per Set of Ratepayers ONLY Considering: Net Imports	2 Degree PFCs	4 Degree PFCs	4 Degree PFCs on 115 kV	8 Degree PFCs	DLRs	4 Degree PFCs & DLRs	Traditional Upgrade	GETs & New Substation
Annual Cost of Solution ($M)	$0.84	$1.44	$0.84	$2.62	$0.40	$1.59	$6.85	$2.76
Net Imports Savings ($M)	$1.26	$2.08	$2.53	$1.85	$2.27	$2.64	$4.37	$0.98
NY Electric Customer	$0.04	$(0.04)	$0.17	$(0.08)	$0.19	$0.11	$(0.25)	$(0.18)
Utility Customer	$0.46	$(0.39)	$1.86	$(0.86)	$2.07	$1.16	$(2.74)	$(1.97)
Person in 7 County Region	$0.92	$(0.78)	$3.71	$(1.70)	$4.12	$2.31	$(5.46)	$(3.92)

INL: 21-50332_CostSavingsTechStrat_r2

These tables clearly show that building new transmission should not be evaluated on an economic basis in isolation. These cases show that many of the transmission upgrades could cost customers more money than the "do-nothing" case. Note that each of the dollar figures in the above tables captured in parentheses [i.e., ($0.04)] represent increased costs to customers. However, the "do-nothing" case itself does not account for asset depreciation as the existing systems grow older. Transmission planning must also consider the generation and load forecasts, and the longer-term trajectory of the system.

Value of Avoided Renewables Curtailment

As discussed above, the value of avoiding energy curtailment is potentially multiple millions of dollars. Avoided curtailment is especially troubling to extrapolate across a multi-year horizon given that the nature of the power grid in NY will shift as real-time generation mixes reach new heights of renewable penetration. Curtailment rules may shift, and energy in this region may need to be curtailed to keep regulating reserves online. Put simply, as the power grid transitions to a greater mix of renewable generation, the incremental value of energy (on a generic MWh basis) diminishes, while the temporal and locational value of capacity increase. Still, it is useful to evaluate the scale of the renewable curtailment avoided in each of these cases relative to the cost of the asset. Table 24 shows the annual savings (cost) per set of ratepayers ONLY considering LCOE of curtailment.

Table 24. Annual savings (cost) per set of ratepayers ONLY considering LCOE of curtailment net of solution cost.

	2 Degree PFCs	4 Degree PFCs	4 Degree PFCs on 115 kV	8 Degree PFCs	DLRs	4 Degree PFCs & DLRs	Traditional Upgrade	GETs & New Substation	Annual Savings (Cost) per Set of Ratepayers ONLY Considering:
Annual Cost of Solution ($M)	$0.84	$1.44	$0.84	$2.62	$0.40	$1.59	$6.85	$2.76	
LCOE Cost Savings ($M)	$4.22	$6.19	$5.09	$8.10	$1.72	$7.81	$13.60	$9.12	LCOE of Avoided Renewables Curtailment
NY Electric Customer	$0.35	$0.49	$0.43	$0.56	$0.13	$0.64	$0.69	$0.65	
Utility Customer	$3.74	$5.27	$4.70	$6.07	$1.46	$6.90	$7.48	$7.05	
Person in 7 County Region	$7.44	$10.47	$9.35	$12.08	$2.90	$13.72	$14.87	$14.02	

INL: 21-50332_CostSavingsTechStrat_r2

Alternatively, to LCOE methodologies, we can assess the impact of the production tax credit (PTC) on wind generation, which provides a tax credit of 1¢–2¢/kWh for the first 10 years of electricity generation for utility-scale wind. The production tax credit would likely flow to the wind project developers rather than transmission owners or customers, which underscores the difficulty in benefits accounting for grid-enhancing technology. Still, the order of magnitude for incremental PTC payments, assuming the 2021 PTC rate of 1.5¢/kWh, are captured in Table 25 below.

	2 Degree PFCs	4 Degree PFCs	4 Degree PFCs on 115 kV	8 Degree PFCs	DLRs	4 Degree PFCs & DLRs	Traditional Upgrade	GETs & New Substation	Annual Savings (Cost) per Set of Ratepayers ONLY Considering:
Annual Cost of Solution ($M)	$0.84	$1.44	$0.84	$2.62	$0.40	$1.59	$6.85	$2.76	
Initial Cost of Solution ($M)	$7.12	$14.24	$7.12	$28.48	$1.82	$16.06	$205.50	$51.06	Production Tax Credit ($1.5¢/kWh) for Wind
Incremental PTC Payments for Modeled Year ($M)	$4.22	$6.19	$5.09	$8.10	$1.72	$7.81	$13.60	$9.12	

INL: 21-50332_CostSavingsTechStrat_r3

Table 25. Incremental PTC payments made per scenario.

The value of GETs is readily quantified here in the context of renewable electricity, but should not be tied solely to that benefit. Section 2.2.2 outlines the multiple values of GETs beyond renewable generation integration. Still, a rate impacts assessment of GETs within the New York region could quickly spiral into a renewable electricity rates impact assessment, which layers additional considerations on top of an already intricate process. Assessing rate impacts of renewable generation would need to include assessments of PTC, ITC, accelerated depreciation, voluntary green power markets (such as green pricing programs), the intrinsic value of the electric system in powering the modern economy, and likely public health considerations. As of 2017 and corroborated with research in support of this report, no single study assesses each of these impacts [57].

2.2.4 Adding a New Layer of Complexity

Each of the risk-mitigating values articulated above requires additional studies tailored to each individual system, layering further complexity onto the local transmission planning processes across the country which are already elaborate by their nature. These processes consider multiple scenarios and stakeholders in an effort to ensure that power remains available to the public in the face of contingency situations. As the bulk-power system is continually modernized to meet changing generation resource mixes and varying load, GETs introduce an additional layer of uncertainty across varying time domains. The study of GETs will be detail-oriented and iterative; finding the perfect location and use case for a GETs installation is a difficult and multi-factor proposition. Even if a given line is selected for DLR, care must be given to identifying the limiting set of spans before the impact on terminal equipment or neighboring lines is assessed and that further downstream elements don't become the limiting elements. A key takeaway from the case study is that finding the *perfect* location for GETs is unnecessary; each scenario that was studied proved promising and worthy of additional inquiry.

As articulated throughout this document, the impacts of GETs can cascade in benefits across the system, but those potentially beneficial impacts must be assessed for unintended reliability impacts.

Because the industry is still learning how to best use GETs, even prioritizing areas of study for the advanced technology can be a study in itself. Section 2.1.2 provides an example. While the methodology found a promising region for GETs for our study, following a similar process elsewhere may indicate that GETs do not make sense in some locations. However, the multitude of potentially compelling benefits warrant additional study, and alternative methodologies, assumptions, and probabilistic analyses may be worthy of exploration.

3 Conclusion

3.1 Summary of Grid Status and Effects of Congestion

The U.S. electric power grid is a complex system divided into three main sections that consist of more than 7,300 power plants, nearly 160,000 miles of high-voltage transmission lines, and millions of low-voltage power lines and transformers. These electrical systems have enabled extraordinary benefits to everyday quality of life but have also increased societies' vulnerability in its absence by the same proportion. This trend will continue as new end uses, such as transportation and space heating, are electrified. Modern life is dependent on the electric grid to provide power consistently and safely, yet the infrastructure underpinning the grid was not designed to support the rapid change needed to achieve ambitious climate goals across the country.

Transmission congestion is a routine issue across the country that occurs when transmission system limits force uneconomic dispatch of generation. The sum of real-time congestion costs (one component of total congestion costs) for 2016 among major system operators was $4.8B [4]. Congestion is a particularly acute challenge facing the economic optimization of a system with a large mix of minimal marginal cost generation (i.e., generation sources with zero fuel cost such as wind and solar). One contributing factor to transmission congestion is that the transmission system is aging and largely operated with decades-old technologies.

3.2 Summary of GETs Discussed

While they may rely on analytics, sensors, and sophisticated control schemes, the technologies considered within this report are demonstrated, deployment ready, and widely used in the power system industry across the world (See Appendix A). However, the recommendations outlined in Section 3.4 would spur adoption of these technologies, particularly as it relates to incorporating new technologies into the existing business practices of operating the power grid. Multiple grid-enhancing technologies were discussed in this document:

Dynamic Line Rating (DLR) computes the thermal limit of a transmission line by considering ambient weather conditions that may cool or heat the line. DLRs capture the actual current carrying capacity of the transmission line at a given time, rather than relying on static or seasonal assumptions. This allows for more accurate and safe operation of the power system, and typically increases the available electrical transport capacity of a line segment above static assumptions.

Dynamic Transformer Rating (DTR) takes a similar approach as DLR but for transformers, which are sometimes the limiting element of the transmission topology. This technology informs operators of the dynamic thermal limit of transformer capacity, which could allow for additional energy transfer.

Power Flow Control (PFC) can take many forms, but is readily segmented into:

- Power System Hardware, which can change the electrical impedance of a line to shift the flow of power in a more efficient manner.
- Topology Optimization Software, which attempts to optimize the configuration and settings within the network of transmission components for more efficient operation while maintaining reliability.

3.3 Summary of GETs in NYISO Region Case Study

The case study presented in Section 2 provides a techno-economic power grid planning study conducted to evaluate grid operations and renewable deployment, with and without PFC and DLR technologies implemented. While this section provides an interesting case study in one renewable region of New York State, the objective of the study was to develop a techno-economic framework for evaluating GETs more generally. As a result, the methodology can be used as a template for future analyses by grid operators, transmission owners, and technology vendors.

Certain values created by GETs can be readily quantified, including reduced congestion, asset deferral, and new generation (renewables) integration. Other values are more qualitative in nature but assist the grid operator to operate an increasingly dynamic and complex power grid. Providing the grid operator with the situational awareness and flexibility afforded by GETs can help in grid contingency situations, or during potential outage events, as the grid may have additional capability, but static assumptions artificially limit system flexibility. GETs can also provide asset health monitoring to transition from reactive maintenance schedules to a condition-based maintenance paradigm.

The case study shows that finding the *perfect* location for GETs is unnecessary; each scenario that was studied proved promising and worthy of additional inquiry. The case study provided proves that GETs can be considered alongside traditional upgrades to optimize infrastructure investments in support of customer and policy interests today. Extensive study and overoptimization could lead to increased ratepayer costs in the time required to decide upon an optimized deployment scheme. Analysis is required, but utilities and regulators should be motivated by the full suite of GETs benefits rather than intricate cost-benefit optimization studies.

Impact on Overall Transmission Utilization

Analysis of the resulting line loading, with and without PFCs included, highlighted a significant increase in line loading across the 230-kV system (left-hand portion of the chart) and a more balanced loading across the 115-kV system. Overall, line loading increases across the network from 35% in the Interconnection Queue case (without PFCs) to 38–49% depending on the number of PFC devices deployed.

Impact on System Operations

As mentioned throughout Section 2.2, the full suite of benefits afforded by GETs may make the difference when considering deployments. DLRs can provide reduced risk by ensuring operations within actual thermal limits, and PFCs can provide increased system flexibility to dynamically adjust to changing system conditions both in real-time operations and across multi-year planning horizons. Neither of those benefits are readily quantifiable, but should be considered in GETs evaluation.

With respect to the values that can be readily quantified, the results of this study suggest that GETs could prove cost-beneficial in avoiding renewable generation curtailment in the short term and remain useful as situational awareness and flexibility resources in the longer term.

A summary of the annual wind and solar generation, curtailment, and avoided curtailment (relative to the Interconnection Queue reference case) were calculated across the nine evaluated cases. The avoided curtailment ranges from 98 GWh/year in the PFC case with ± 2-degree angle changes to 188 GWh/year in the PFC ± 8 degree angle changes. This represents a 23% to 43% reduction in curtailment without conventional transmission upgrades included.

The DLR case showed minimal reduction to annual curtailment; however, this was unique to the case study evaluated, which saw DLR higher than SLR during the summer period when solar curtailment was highest. This is because the DLRs, on average, decreased line ratings relative to the static line ratings during the summer months when temperatures are higher and wind speeds are lower. This results in higher curtailment, namely solar during May through September, but lower curtailment of predominantly wind generation in other months. Despite DLRs proving to be more limiting than static ratings on average in this case, they alleviated curtailment in some months and provide system operators with greater visibility into safe operation of the target power lines.

Various DLR and PFC cases were evaluated against a traditional upgrade case that involved upgrading many of the lines and transformers to higher rated equipment. While the traditional upgrades yield higher curtailment reductions, they are also more expensive to deploy. As a result, GETs deployment that reduces some, but not all, curtailment may be a more cost-effective method to integrate new generation in this area while providing more overall system flexibility.

Overall Impact for Ratepayers

The results indicate that GETs can be a beneficial intermediate point, where wind and solar are added to the system while longer-term transmission upgrades can be planned and deployed. Ultimately, new transmission will be required to reach the elevated levels of renewable generation planned for in New York State’s 70% by 2030 clean energy plans. GETs can be a key enabler to that transition and reduce and defer (but not eliminate) the need for new transmission. A similar finding in other jurisdictions is likely.

- **Avoided Curtailment:** The savings estimated from the case study vary based on the scenario evaluated. Blanketing the region with DLR resulted in $1.7 million in avoided curtailed energy value over the year studied. Combining that DLR with PFCs and a new substation (The GETs & New Substation case) resulted in energy value saved of $9.1 million. Meanwhile, reconductoring most of the lines in the region and building a new substation (the traditional upgrades case) resulted in $13.6 million worth of energy over the year. However, these values do not include the cost of building GETs or transmission upgrades, which are evaluated in Section 2.2.2. While the traditional upgrades avoid more curtailment, they are also more expensive to deploy. As a result, because GETs reduces a large portion of the curtailment at lower cost, they may be a more efficient use of ratepayer funds.
- **Imports and Exports:** Another area of benefits, albeit smaller, are impacts to NYISO's net imports. These savings, ranging from about $1 million to almost $4.4 million per year, highlight the impact of how reducing congestion in the Hornell and South Perry Transmission Zone impacts net imports across the entire system. It is important to note that a greater or lesser reduction in net imports on a GWh basis does not always translate into the same level of cost savings. This dynamic may indicate that DLRs provide the most robust curtailment relief benefits in regions with relatively high amounts of wind compared to solar deployment. This is due to the timing of those imports. A certain technology, such as in the With DLRs case, may reduce net imports by only 4 GWh versus the Interconnection Queue case, but it also allows all remaining net imports to be managed more efficiently.

3.4 Recommendations

Throughout this document, recommendations for additional research, refined approaches, and a foundational methodology for considering GETs were outlined. In addition to those areas, and informed by challenges that the authors of this document found in working on this project, key recommendations are outlined below:

Selecting Locations: The impact of DLRs and PFCs is highly location-dependent. While DLRs often unlock additional capacity, the DLRs developed for the case study presented in Section 2 did not represent significant capacity improvement, though the DLRs were more important for wind generation curtailment rather than for solar. The findings in other regions, with different weather patterns, geological topographies, and underlying infrastructure may be different or may begin to form general guidance. Conversely, the network configuration in this region was well suited for the PFC approach. Studies similar to the one performed herein should be completed in regions considering GETs to assess impacts on the local transmission infrastructure.

GETs Should be Considered: Similar to how valuing storage in legacy market constructs proved difficult, the values associated with GETs are not typically prioritized by transmission planning. The flexibility and operational optimization across the year are not valued in a world where reliability planning is tantamount. FERC recently announced an Advance Notice of Proposed Rulemaking (ANOPR), *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, which would formalize this consideration [58].

To provide more actionable suggestions, planners and regulators can examine the role of RTOs and regional planning, both of which utilities have cited as impediments for GETs deployment. For instance, the Commission could explore requiring RTOs to modify their software to accommodate various types of GETs or consider them as options for network upgrades for interconnecting resources.

Assemble a Task Force to Share GETs Data: Electric utilities are traditionally risk-averse organizations. The gaps in public knowledge with respect to GETs leads utilities to established, known solutions. A task force would ideally include public, private, and vendor communities, aimed at providing the data necessary for fair GETs consideration to ameliorate perceived risk of the modern technology. Such data would include:

- **Budgetary Cost Estimates:** Cost estimates for traditional system upgrades are readily available and maintained by ISOs and National Labs. Detailed literature for GETs capabilities is not widely available, nor is a consistent cost range available in academic studies. Providing industry with passive cost estimates will help planners consider the technology.
- **Hour by Hour Usage:** The capabilities of GETs are well understood, but the practicality and real-world usage of GETs is less documented. Understanding how the GETs that are deployed are being used will help planners consider their usage.
- **Deployment Challenges:** Incorporating any new technology will include challenges. Understanding integration challenges, including data models and communication shortfalls, and the techniques used to overcome them will assist in alleviating utility concerns.
- **Workforce Development:** Many modern grid technologies seem to be stuck in a cycle of “pilots” where the technology is considered in isolation, rather than as part of the new “business-as-normal.” Shifting organizational thinking is possible by requiring enhanced training for planning engineers & grid operators such that they are trained and versed in new approaches when faced with the implementation of innovation. The training would need to be delivered by a neutral party whose mission is education, rather than selling a product or service. There is training readily available from both industry and DOE, but there are few consistent requirements for system planners or grid operators across the country to take the training.

Further Research is Needed to Accelerate Adoption: The case study outlined herein and those found in other recent works advance the methodologies and public knowledge surrounding GETs, but additional research could further modernize bulk-power system planning and operations:

- The holistic operation of an advanced and modern grid would include the GETs studied here (PFCs and DLR) along with DTR, energy storage, and dispatchable demand side resources, such as demand response. A study should be completed evaluating that full set of solutions alongside traditional upgrades.
- There is no methodology to identify the optimal solution set of GETs alongside traditional upgrades. While this study considered multiple technology strategies, it did not identify *the optimal portfolio* of GETs and/or traditional upgrades. Building on the framework outlined in this report, a methodology and toolkit should be developed to focus the optionality on a specific solution set.
- Due to the timeline associated with the completion of this work, this study was completed without direct input of insiders at the ISO/TOs. Future work should aim to include resources in a public/private partnership to advance this work aligned with the needs of those implementing the methodology. In particular, the perspective of transmission planners and system operators would be helpful in order to determine how GETs could be integrated to improve efficiency while maintaining reliability.
- There have been no projects that demonstrate transmission capacity forecasting methodologies integrated within market constructs. Tools and studies should be developed to identify feasible and reliable methodologies for incorporating forecasted DLR into generation dispatch decision-making, which consider market rules, forecast availability, forecast accuracy, weather variability, and computational feasibility for a given region.
- The cost of congestion is market specific and highly dynamic. Improving stakeholder understanding with a visualization platform could improve the identification of transmission upgrade locations. More accessible information would likely lead to more studies, potentially identifying cost-effective technology investment opportunities.

Benefits / Cost Allocation / Incentives: The incentives to build GETs are often misaligned with those who benefit most. Transmission owners, generation developers, utilities, independent system operators / regional transmission organizations, and clean energy advocacy groups have various primary objectives, but their primary focus is not solely on the efficient economic planning and operation of the power system. Consumer advocates are often underfunded and lack the expertise to influence key engineering activities driving the investments at the bulk system. Mechanisms are needed to ensure GETs are implemented and utilized for the benefit of ratepayers as appropriate. The challenges with cost allocation and incentives are a key objective of a recent FERC ANOPR [58].

GETs can provide benefit in a future system heavily reliant upon variable renewable energy, particularly in bridging the gap between today’s infrastructure and the grid needed to support ambitious climate goals. These recommendations are intended to transition GETs from promising potential capabilities to a practicable solution set utilized throughout the industry to improve the power system.

APPENDIX A

Updates on GETs Overview and Considerations

A.1 Dynamic Line Rating Technology

A.1.1 Background

Traditionally, transmission operators have used the SLR method, which assumes constant environmental variables in the heat balance equation.[g] More broadly, transmission operators are using seasonal ratings, which adjust those static assumptions depending on the time of year. Recently, some transmission operators have adopted AAR, which adjust line ratings based on ambient air temperature, but do not account for wind or solar effects. Across the U.S., various methods are employed [2]. In recent years, attention to DLR methodology has increased. DLR uses real-time monitoring or forecasted weather conditions in the heat balance equation to give a more accurate representation of the true ampacity of the conductor. Using the actual weather information often results in higher line rating ampacity than what is assumed in SLR. Therefore, power flow is unnecessarily limited when using SLRs as conductors are not actually at their thermal limits. When this happens, operators are forced to route power along transmission lines that have available capacity at the cost of more expensive generation.

Many Regional Transmission Operators (RTOs) and Independent System Operators (ISOs) choose to utilize different values for the weather variables to calculate SLR ampacity. For instance, they may use historical local weather data in their region to get a better estimate of the weather variables and in return get a better estimate for the ampacity of a conductor in their area. Some have chosen to use seasonal SLRs to take advantage of lower ambient temperature in the spring, fall, and winter. Another approach is to allow for a higher conductor temperature. All of these strategies inch toward DLR.

To attain better situational awareness of transmission conductors and safely increase their ampacity, the adoption of DLR methodologies is gaining traction. Today, there are many technologies and methodologies for determining the real-time or forecasted ampacity of overhead conductors. In principle, DLR is based on the same heat-balance equations as an SLR but improves upon static ratings by utilizing of a time-varying approach based on real-time or forecasted environmental conditions [17].

[g] Southwire, one of the world's leading manufacturers of wire and cable, gives guidance on the ampacity rating of conductors using SLR. Southwire calculates the ampacity rating of conductor by using the following assumptions: a maximum allowable conductor temperature of 75°C, ambient temperature of 25°C, wind velocity of 2 ft/s perpendicular to the conductor, heat emissivity of 0.5, and full sun [12]. These environmental conditions are assumed to be conservative, and thus, maintain a safe operation of the transmission conductor.

A.1.1.1 Tools

DLR Tools Overview

The DLR for a given span of a transmission line can be determined in several ways. Methods for DLR largely fall into direct line-monitoring or indirect weather-based methods. Direct methods utilize measurements that rely on monitoring the conductor and can be accomplished by observing the current load or the conductor's tension, temperature, or sag. Devices can be mounted on the conductor, nearby structures, or the ground to record these measurements. The instantaneous load combined with one or more of these values can determine the additional ampacity available on the conductor to avoid exceeding sag or temperature limitations. Indirect methods infer the conductor's ampacity and can be done through replica modeling or through weather-based approaches. Weather-based approaches can use real-time weather data or forecasted weather data in the familiar set of IEEE-738 equations to determine the ampacity of a line as the weather conditions change.

Weather-Based DLR Vendors

Weather-based DLR [77] application models wind at high-spatial resolution via Computational Fluid Dynamics (CFD) and computes thermal conditions using IEEE-738 conductor-temperature relations [59]. This approach allows for a span-by-span physical modeling of the transmission line with minimal use of weather monitoring stations.

Another weather based [60] DLR service provides observed and forecasted ratings relative to available capacity for what it determines to be the most critical sections of a power line based on weather. The service provides hotspot analysis modeling by calculating the historical weather-related cooling capacity for each section of a power line over a 10-year period and determining the most critical spot for each hour. Over this 10-year period, the sections that are most often the critical spot are referred to as "hotspots." An operation weather forecasted model is used for these hotspots to develop forecasted DLR values.

Direct-Monitoring Based DLR Vendors

Direct-monitoring based [61] ratings are derived from conductor behavior regarding conductor temperature, ambient temperature, load, and the conductor's clearance-to-ground measurement. This is a software and hardware solution that functions as a DLR system, but uses patented clearance sensors as well as statistical correlation and forecasting techniques to determine the behavior of the line when load and weather fluctuates [61]. This DLR rating can be found when transmission line monitoring equipment are installed on spans that are close to the distance-to-ground clearance (clearance limited). The use of clearance-limited spans ensures clearance requirements are not violated while also eliminating risk of conductor thermal damage.

A second direct-monitoring [62] suite is made of stand-alone sensors installed on high-voltage lines, coupled to software interfacing with dispatching centers' supervisory control and data acquisition (SCADA) software. This system also forecasts ampacity up to 2 days in advance. The tools provided are ampacity quantification and modeling tools based on historical weather data, self-powered vibration sensors with GSM data transmission, data-acquisition and ampacity computation real-time engine, 1–4 hour forecasts, and 60-hour forecast.

A third direct-monitoring service [63] provides forecasted line ratings with customizable confidence intervals. Forecasted line ratings are validated in real-time by field measurements, such as conductor sag and vertical clearance from ground for each individual phase, horizontal conductor displacement/blowout for each individual phase, conductor tension, conductor temperature, circuit current, MW, MVAR, MVA, and Power Factor. The sensors can be used to provide icing alerts, galloping alerts, local ambient weather conditions, anomalous motion alerts, and user configurable alert notifications. The sensors can also monitor line health.

A fourth direct-monitoring option [64] combines specialized sensors and weather information within a CIGRE mathematical model that enables accurate information of the maximum current that the conductor can carry. The sensors simultaneously measure conductor temperature, icing induced sag, ambient temperature, humidity and current of power lines. Measurements are carried out directly at the fixing points on the overhead line (OHL) phase conductor and are transmitted to software.

A.1.2 Deployment of DLR Monitoring Systems

Installations

Direct contact sensors can be installed by clamping the hardware on the conductors. Distance to ground can also be measured with sensors installed on poles or on the ground. Many modern conductor sensors do not require line outages and can be quickly installed. For weather-based approaches, the monitoring systems consists of common weather stations that can be installed on transmission poles rather than on the conductors.

Locations

The implementation of DLR equipment on all the transmission lines may not be economically feasible. Therefore, one consideration in implementing DLR is the prioritization of transmission segments. Lines can be selected for DLR deployment based on their typical load levels, with first choice to lines that are heavily loaded.

Other approaches have been outlined in literature, including:

- Selection of lines to monitor considering impacts on fuel cost (see *On selecting transmission lines for dynamic thermal line rating system implementation*) [65].
- Simultaneous optimization for the minimizing power generation costs and load shedding, while maximizing renewable energy systems integration (see *New DTR line selection method in a power system comprising DTR, ESS, and RES for increasing RES integration and minimizing load shedding*) [66].

Generally, the monitoring locations on the selected lines should include the critical sections. That is, the sections that may limit the overall line's rating. Some guidance on identifying critical spans and selecting the number of monitoring systems can be found in the literature (see *Identification of Critical Spans for Monitoring Systems in Dynamic Thermal Rating* and *Critical span identification model for dynamic thermal rating system placement*) [67] [68]. The number of monitoring systems will depend on the overall length of the line, the complexity of the terrain, and the accuracy tolerance.

Communication Networks

Successful implementation of DLR requires the ability to communicate between the sensing or monitoring technologies and the control rooms or other decision systems in a timely manner. Many different technologies—radio, cellular networks, satellite, fiber optics, and physical media—can be used as communication channels. However, the choice of technology will depend on the monitoring approach as well as requirements of the application, especially with respect to data-transfer capacity and latency levels. For example, simple weather stations only need to transmit a few environmental parameters to the control center on a regular basis. For these small data packet applications, many existing technologies can be used, and the choice becomes dependent on cost, terrain, and network availability. As the number of capabilities and measured parameters increase for sensing and monitoring technologies, the communications requirement to manage the availability, latency, and integrity of larger data sets will also increase.

Security

As utilities and system operators begin to rely on DLR systems for control, dispatch, and market decisions, the DLR system and communications channels become critical assets and will need to meet NERC's Critical Infrastructure Protection (CIP) standards and requirements to ensure the authenticity and integrity of DLR data. Corruption of this data from any cause, unintentional or deliberate, becomes an operational problem that can have significant consequences. DLR system owners and service providers need to ensure the reliability of the communication systems, including the cybersecurity of the sensing and monitoring technologies, the communication channels, and the operating systems. Cybersecurity breaches can manifest as data disruptions or poor data integrity that seek to invoke bad decisions or manipulate markets. System operators will need strategies and solutions for detecting and mitigating problems in communications.

A.1.3 Implementation Considerations

Accuracy and Reliability

The accuracy and reliability of DLR is critical to successful deployment and realization of cost savings, but inaccuracies can arise through both measurement and modeling errors [69]. Measurement errors include imprecise or inconsistent measurements and improperly calibrated sensors. DLR systems can also malfunction, in whole or in part, such as during a loss of communications connectivity. Additionally, some direct-measurement sensors are not able to measure transmission line parameters accurately during periods of light loading [70]. In these situations, there is always the option to revert to SLRs if the system is aware of the malfunction.

Modeling errors encompass inaccurate mathematical rating models, weather forecasting errors, and errors in collecting circuit topological and conductor data. For example, the thermal and mechanical properties of the conductor in older power lines may shift over time due to aging and past use, yielding inaccurate results in clearance calculations.

Similarly, CIGRE has documented that emissivity of overhead transmission lines can also change as lines age, affecting solar radiation impact and thermal-radiative properties [71]. Since inaccurate parameters could ultimately lead to incorrect ratings, proper characterization of the transmission line itself should be made prior to implementing DLR.

These various sources of error reduce confidence in the capability of DLR to perform accurately and reliably. Developing methodologies and solutions to address these concerns will be critical to broader DLR adoption. Some strategies currently under investigation have employed a mathematically described confidence margin within the DLR calculation (either applying the margin to the forecasted weather inputs, or to the rating overall), which rates the power line more conservatively proportional to lower confidence parameters such as weather predictions [72].

Variable Ratings in System Operations

DLR has not yet gained wide acceptance by utilities, mainly because system operators need to be confident in the DLR system to provide accurate ratings with high availability and reliability [73]. Due to this, the accuracy of the calculated rating, confidence and reliability of the DLR-provided ratings, and continuous availability of line rating are significant for real-time integration of DLR into system operations [70].

Although system operators may benefit from dynamic line ratings in relieving power flow constraints, the volatility and varying nature of the ratings and the difficulty to predict ratings in advance can be a challenge for them. Power system operators generally adopt fixed line capacity limits to plan dispatch. Many system operators may be hesitant to accept the challenges of DLR technologies as they are chiefly tasked with maintaining system safety and reliability, not about the economy of system dispatch achieved by reducing system congestion.

Dispatching the line based on highly variable real-time ratings is not practical due to generation dispatch and load response limitations. If the weather conditions, and thus DLR, change suddenly, the generation or load would have to respond quickly to avoid exceeding conductor temperature limits.

To minimize the rating variability, the average value of ratings over a time horizon can be considered. Moreover, limiting the range of rating values can be considered as another solution to smooth the high variability of line ampacity values.

Variable Ratings within ISOs

Another complication is that data needs to be shared between different utilities and between utilities and regional transmission organizations. This can cause complexities, including that the utility rates the lines by MVA and the System operator by amperes. Another complication is that network models may not be similar among organizations. Cybersecurity rules may complicate data transmission and disallow use of common carriers, for example. Market sensitive information may not be allowed outside control room firewalls. For example, actual current of a line is market-sensitive information and is not generally provided for nonoperating personnel or entities.

Required Investments from Utilities

Using greater transmission capacity through DLRs also means that the grid hardware components (e.g., power lines, transformers) will operate closer to their design limits, potentially accelerating aging effects [74] and driving the power system to a more fragile state if these impacts are not adequately taken into account. Implementation of DLR must include principles of resilience to ensure that new hazards are not created. These additional considerations and issues will impact the business and operating models of utilities and other stakeholders.

As DLR is implemented on a circuit, transmission owners and operators must focus on other critical elements to ensure the grid can handle the increased loading without issues. In addition to potential impacts on grid hardware components, protection systems may need to be examined. For example, relay settings may need to be updated to correspond to the increased capacities enabled by DLR. Regulatory limits on the upper bounds allowed for DLRs may be required to avoid these issues, as well as to address risks that can occur with rapid decreases in the line ratings. Power-system protection is an area that is getting more complex with adoption of new technologies, especially with significant growth of inverter-based generation.

A.1.4 Case Studies

Table 26 lists known case studies conducted in North America along with a description of the experience. While these results are generally favorable toward the benefits of DLR deployments, outcomes are difficult to extrapolate beyond the targeted lines.

This report aims to further evaluate the potential benefits of DLR in the context of using other GETs by providing a case study for the New York region. Details of the DLR implementation are described in Appendix A. The production modeling and operational and economic impact assessments are presented in Section 2.

Table 26 DLR case studies in North America.

Entity	Year	Summary
NYPA	2013	The demonstration project evaluated a variety of DLR systems and technologies, and how they could be used in transmission system engineering, operations, and planning. They found a positive correlation between increased real-time capacity and increased wind generation, and capacity increases of 30 to 44% over static ratings [75].
Oncor	2013	The demonstration project focused on monitoring an entire transmission line and included DLR integration into control systems. They observed capacity increases between 6 and 14% over AARs, available over 83% of the time. Additionally, they determined their DLR system could increase line capacity, on average, between 30 and 70% relative to static ratings [75].
Idaho Power	2013-2018	Weather-based DLR provided increased situational awareness for more than 450 miles of transmission lines in highly complex terrain. Contingency relief has been realized multiple times as DLR forecasts are researched and validated [76] [77] [78].
AltaLink	2015	Conducted an analysis for a wind plant installation in Canada and found concurrent cooling avoided the need for system upgrades, saving the wind developer an estimated two million dollars. Further analysis showed an average 22% capacity increase over static ratings 76% of the time [79].
AEP	2016-2017	Conducted a study of DLR applied to a 345-kV line across three spans. The results found significant capacity increases on the targeted line with the potential of $4M in savings [22].

A.2 Dynamic Transformer Rating Technology

A.2.1 Background

As previously mentioned, GETs have the potential to unlock more capacity on existing infrastructure. However, that extra capacity is only useful insofar as it is carried throughout the electric power system from various generation sources to the end user. For example, extra capacity on one transmission line span is only useful if the next span can also accommodate it. This idea is applicable throughout the power system, including within the substations that facilitate power transfer. To use an analogy, DLR has the potential to expand the Nation's power highway system, but the exits and intersections must be capable of using that new capability for it to be worthwhile. At the nexus of these power system exits and intersections are transformers, often the biggest and most expensive component(s) of a substation.

Transformers shift power between voltages, helping to facilitate “step-up” and “step-down” transitions throughout the power system. They have long been recognized as vital for the resilience of the U.S. electric sector [18] [19]. Because of the power system’s reliance on transformers, ensuring the health of these assets is important. Therefore, utilities set and maintain standards for their performance and loading. Design standards vary across the country, but generally follow guidance from IEEE working group 57 and the IEEE/ANSI C57.91 standard [20]. Although transformers can safely operate above the nameplate rating from the manufacturer, this practice has the potential to accelerate the aging effects on the transformers, potentially driving the power system to a more fragile state if these impacts are not adequately addressed [17].

Layering on top of the operational contingency concerns with respect to a failing transformer, these assets are expensive to replace and can take months to purchase and deliver. In 2014, DOE defined large power transformers (LPTs) as those with a maximum nameplate (i.e., nominal) rating of 100 megavolt-amperes (MVA) or higher. LPTs can cost millions of dollars and weigh between approximately 100 and 400 tons (or between 200,000 and 800,000 pounds) [19]. Regarding the lead time on LPT, a 2014 DOE report stated: “In 2010, the average lead time between a customer’s LPT order and the date of delivery ranged from five to 12 months for domestic producers and six to 16 months for producers outside the United States. The LPT market is characterized as a cyclical market with a correlation between volume, lead time, and price. In other words, the average lead time can increase when the demand is high, up to 18 to 24 months.” [19]

Because of the long lead time and expense, transformers are often oversized for their initial application. However, transformers are long-life assets—in 2014, the average age of LPTs serving the grid was 38 to 40 years, with approximately 70% of LPTs being 25 years or older [19]. Using a single asset for that length means that the transformer loading may shift over time as new customers are served. Furthermore, transformers can support contingency or maintenance situations wherein neighboring circuit loads are transferred to their service, utilizing the available transformer capacity.

Reports generalizing the limiting element of a given transmission corridor are not readily available. A 1996 report on the New York power system [21] outlined that the conductor itself served as the thermally limiting element about 42% of the time. The same report outlined that transformers served as the limiting element nearly 10% of the time with other substation equipment, such as current transformers (used in metering) and circuit breakers, contributing to the rest of the thermal limits. PJM noted that the substation often proved to be the limiting element in a DLR study in 2018 [22].

Dynamic transformer rating attempts to use additional transformer capacity to prevent congestion while still limiting potentially detrimental thermal impacts on asset health, similar to DLR for power lines.

A.2.2 Dynamic Transformer Rating Methods

Dynamic transformer rating (DTR), like DLR, attempts to monitor the transformer operating temperature and actively determine power limits based on thermal thresholds or electrical insulation loss of life calculations. Ambient temperature, amount of electrical current delivered to the transformer, age of the transformer, and type of cooling systems installed are the main variables which dictate the transformer's operating temperature, and consequently its thermal rating limit.

Transformers are typically rated using a simple criterion to never exceed a static current (or power) rating. The exact loading thresholds may vary based on system condition (normal, contingency, or short-duration emergency) and season (summer or winter). However, these ratings attempt to capture transformer conditions categorically (similar to SLR in transmission lines), rather than through active monitoring. The threshold methodology is used in recent research on the topic of distribution planning and is generally well accepted [80].

An improvement in accuracy over the threshold criterion is to use dynamic thermal limits [81]. The temperature profile within a transformer is not uniform. Areas where excessive localized heating occurs are known as hot spots and tend to be the primary cause for transformer degradation (i.e., electrical insulation) and failure. Because finding the exact hotspot locations within a transformer is difficult, a combination of sensors and transformer models are employed to estimate hotspot temperatures. Monitoring the hotspot temperature, either directly or indirectly, makes it possible to benefit from the thermal inertia of the transformer, in particular the thermal inertia of its oil. This is the core principle of DTR.

The idea of thermal inertia is most obvious with respect to a transformer serving a PV plant. In Figure 28, the current passing through a dedicated PV transformer is plotted relative to the temperature of the transformer. The temperature lags behind the current as the day goes on. This is because the thermal mass of the transformer slowly normalizes to the heat disbursed by the current passing through the transformer. Mixed-use transformers, such as those serving the transmission and distribution systems, do not benefit from this same diurnal pattern, thus the transformers may operate at a more constant temperature, riding through daily and hourly fluctuations [82].

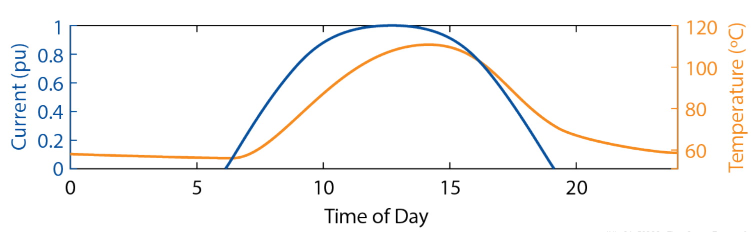


Figure 28 Current and temperature of a dedicated PV transformer.

Approaches to DTR vary, but typically involve a combination of ambient weather-based monitoring solutions, and direct transformer monitoring. Transformer monitors may be stand-alone temperature sensors at various points in the transformer, which engineers use to monitor transformer conditions, or a comprehensive microprocessor-based solution for DTR. Dedicated DTR solutions can consist of multiple measurement units integrated with system control software that leverage different measurement types, such as transformer loading (provided by meters); power draw from transformer cooling system (via meters); top, bottom, and load tap changer tank oil temperature measurements (provided by resistive temperature detectors); status updates from any digital control equipment associated with the transformer (e.g., tap changers or cooling systems); and coil measurements (via fiber optic probes).[h] These measurements can be combined with distributed or centralized control units and knowledge of the transformer characteristics to compute the dynamic rating and control transformer functions such as tap changer location or level of cooling. These systems are generally flexible to accommodate upgrades or modifications to the transformer systems.

A.2.3 Benefits Characterization

The benefits of DTR are similar to DLR in that they more accurately represent system capabilities compared to the traditional static rating approach, usually unlocking additional capacity. While the entire power system would gain from DTR and associated increase in transformer capacity, renewable energy technologies, such as wind and solar, represent significant potential for DTR. Wind and solar farms generally size transformers to account for peak energy generation and non-ideal weather conditions. These peak energy generation and poor weather conditions coincide infrequently, which causes the transformer to operate well under its nameplate rating for the majority of the time.

It is estimated that transformers supporting wind farms operate under the nameplate rating 90% of the time, which results in efficiency losses [83] [84]. By dynamically rating the transformer, wind farms could support an additional 30–50% energy generation capacity, without the need for investing in additional transformers, and experience increased revenue by 10–30% [85].

Similarly, transformers dedicated to PV plants experience diurnal loading conditions, which provides an opportunity for the transformer thermal inertia to ride through peak loading conditions. This opportunity for transformer sizing based on thermal characteristics should be weighed against potential shifts in PV plant operating characteristics over the lifecycle of the plant. PV plants can be retrofitted with batteries or dual-axis tracking that could prolong the effective peak output of the plant, thereby elongating the period of time in which the transformer is heated.

DTR can apply to the transformers at the distribution system as well. Customer-sited PV has been proven to cause voltage issues on these systems. While DTR in itself will do little to correct these issues, the combination of DTR with other voltage management strategies can increase hosting capacity. One study on a notional IEEE bus system found that DTR and voltage

[h] A “Load tap changer” or simply “tap changer” is a device used to adjust transformer voltage output.

management increased hosting capacity by up to 60% [86]. Without active voltage management, DTR was only able to provide benefit where overvoltage issues were not the main limiting factor.

Similar to DLR, the benefits and opportunity of DTR hinge on the *dynamic* nature of the ratings. By more closely monitoring the transformer conditions, system operators can safely operate equipment at high loading conditions. This is particularly useful as the quantity of electric vehicles charging at the distribution system figures to grow rapidly in the coming decade, meaning increased loads on systems that cannot be upgraded in time across the country. In this sense, DTR in coordination with effective charging management strategies figures to benefit electric vehicles by unlocking available capacity and guiding charging to times when the system has appropriate headroom [87].

As discussed above with respect to voltage management and electric vehicle integration, the maximum potential of DTR is unlocked when DTR approaches are used with other strategies. One such pairing is a DTR+DLR application. Using weather data collected from Denmark, Viafora et al. showed that specific locations on the standard IEEE 24-bus system required both DTR and DLR to realize any system benefit [88]. DLR coupled with DTR enabled up to 50% additional power grid capacity and 7–11% reduction in load-dispatch costs. It was noted that system dynamic ratings were more limited by transformer hot spots in the winter and overhead conductor temperature during the summers. However, this trend may be different for geographical locations with alternative weather patterns. This DLR-DTR dynamic did not play out everywhere throughout the IEEE 24-bus model, which implies that system planners would need to perform their own studies to determine which unique bottlenecks within their system could be solved with dynamic ratings.

A.2.4 Implementation Considerations

DTR is most useful for transformers where direct monitoring is available or where the substation location affords reliable calculations of transformer temperature (i.e., ambient conditions are known). Just as with DLR, weather-based DTR must interpolate nearby weather station data to the location of interest. DTR primarily relies upon ambient air temperature for calculations, unlike DLR, which require additional schemes for accurately measuring and predicting wind. However, local hot spots and nearby thermal factors can influence DTR, particularly in urban environments. Of note, the rating of underground substations and transformers is minimally impacted by outside air temperature, and the heating/cooling architecture of underground equipment can create complex dynamics that require separate, potentially unique models to assess thermal ratings [89].

The thermal inertia or heat accumulative effect must be considered with DTR. The nature of DTR requires a holistic temporal planning framework in addition to snapshot steady-state assessments. Although a snapshot analysis may reveal that a given rating is allowable for a transformer, that rating may not be appropriate for extended periods of time. Given the variety of economic and power systems planning tools and considerations that are used in the procurement and implementation of LPTs, temporal planning of this nature could present a barrier to implementation.

A.2.5 Case Study

Many utilities adjust their transformer rating schemes based on seasonal ratings and some have implemented dynamic schemes that consider a range of dynamic solutions, but literature is sparse on DTR-centric case studies.

Table 27 Dynamic Transformer Rating Case Study

Entity	Year	Experience
Unison Electric	2012	Upgraded 50 power transformers (rated from 5-50 MVA) across their entire system. Benefits of the upgrade included extending useful life of existing infrastructure, more flexibility on the system during outages (planned or unplanned), and enhanced situational awareness on device health monitoring. Challenges included retrofitting transformers, and hot spot identification.

A.3 Power Flow Control Technology

A.3.1 Background

In current bulk electric system operations, electricity flows toward paths with the least impedance according to the laws of physics. Power flow in alternating current (AC) systems is unlike other flow problems such as in transportation or telecommunications. In a transportation system, trucks can be routed along a desired path from a source to a destination. Similarly, in a communications system, packets can be routed such that they travel along the quickest path between a sender and a receiver. However, electricity must follow the path of least impedance so power flow is not routable and cannot be directly controlled. Power flow control is also different from other types of flow problems since electricity must also be produced exactly when it is needed. In other systems for distributing goods, products can be stored in a warehouse until they need to be sent to the end user. If the desired supply is unavailable, the end user can wait, and it will arrive later. In power systems, customers are in control of how much power they use and always expect that amount of power to be available.

The power flow control problem is further complicated by the highly interconnected structure of transmission networks typical in North America. Effectively, there are many smaller sub-systems which ensures that when elements are unexpectedly made unavailable, the difference can be compensated by generators and other sources in the system. There are controls in place to isolate faulted areas quickly, limiting service interruption to customers. However, a utility cannot effectively control how much power flows through its network due to the interconnections with other systems. When a transfer between two areas occurs, it impacts the flows on other lines in the system, potentially even for lines which are far away. These unintended flows due to interconnections can restrict transmission capability since the available transfer capability (ATC) of an interface is limited by the first line to reach its transmission limits. Even a single overload can prevent many transfers from being able to take place [2].

A.3.2 Hardware

Power Flow Control is a set of technologies that push or pull power, helping to balance overloaded lines and underutilized corridors within the transmission network. As mentioned earlier, several power flow control solutions exist, such as series reactor, phase shifting transformer, Static Series Synchronous Compensator (SSSC), and Unified Power Flow Controller (UPFC).

Flexible Alternating Current Transmission Systems

Series FACTS devices control power flow, and to a lesser degree terminal voltage, by changing the effective impedance of the line. Idealized devices consume no real power and thus operate in quadrature to line current but practical series FACTS devices have losses; thus, they require operating at an angle slightly removed from orthogonal to line current [90]. The price of FACTS solutions offering dynamic response, such as the SSSC and UPFC, are in the range of $150/kVA to $300/kVA. Phase shifting transformers without dynamic control capability are in the range of $30/kVA to $50/kVA.

Although FACTS devices are well-understood from a technical perspective, they have not experienced the massive deployment that their theoretical advantages may warrant. Fortunately, rapid technology advances in computing, wireless communications, microprocessors, electronic devices, and other technologies over the past two decades have resulted in smaller equipment that is less expensive. These improvements allow FACTS concepts to be revisited from a fresh perspective. Recently introduced distributed flexible AC transmission system (D-FACTS) devices offer such an opportunity [91] [92]. Compared to other PFC devices, such as conventional FACTS devices, D-FACTS devices are particularly small and light-weight.

D-FACTS devices are an improvement over conventional FACTS devices because they have a unique ability to provide distributed reactive support to locations in the system where it would be the most useful. Rather than being housed in a separate building on the ground, D-FACTS devices clamp onto transmission lines and can be made to communicate wirelessly with other devices or with a central controller. Communication allows coordination among the controllers to select settings that achieve a unified objective.

Phase Angle Regulators

Phase angle regulators (PARs) help the transmission operator control flow through a given path similarly to FACTs devices. Power flow through an AC line is proportional to the sine of the difference in the phase angle of the voltage between the transmitting end and the receiving end of the line. PARs control the flow through a given line by directly manipulating this angle.

While PARs are widely accepted in the industry, the largest drawback is the cost. For example, a recently-installed PAR between Michigan and Ontario has an annual carrying cost of over $10 million, making the installation of multiple PARs throughout the system an expensive option.

Some power flow control devices alter the reactance of a line to control the flow. Increasing the reactance will push away power flow while decreasing the reactance will pull in more power flow to the line. For example, series capacitors have been applied in power systems to increase transfer capability of long transmission lines for several years. These devices typically cost significantly less than PARs, can be manufactured and installed in a shorter time, and are scalable.

A.3.3 Software

Transmission Topology Control (or topology optimization) is a simple software application designed to better control power flows using existing hardware deployed on the transmission grid (circuit breakers and communication systems) that is often untapped by existing software. Diversity in demand, supply and transmission facility characteristics result in some facilities carrying more flow than others, not necessarily in proportion to their capacities. Frequently, few transmission facilities are congested and most of the system has spare capacity. Given the redundancy built into the system by grid planners, usually there are reconfigurations that can route power around congested facilities, using uncongested parts of the system. Topology control improves the overall transfer capability of the system by changing the distribution of the power flow on any individual line.

For a given system, the flow distribution depends on location and levels of generation and load, and the transmission topology that connects generators to loads. The reconfigurations are implemented through switching on and off existing high-voltage circuit breakers. By more evenly distributing flow over the network, topology optimization increases the transfer capacity of the grid [93]. Because this is a software application, the cost can be quite low compared to most hardware solutions.

A.3.4 Case Studies

Table 28 Power Flow Control Case Studies

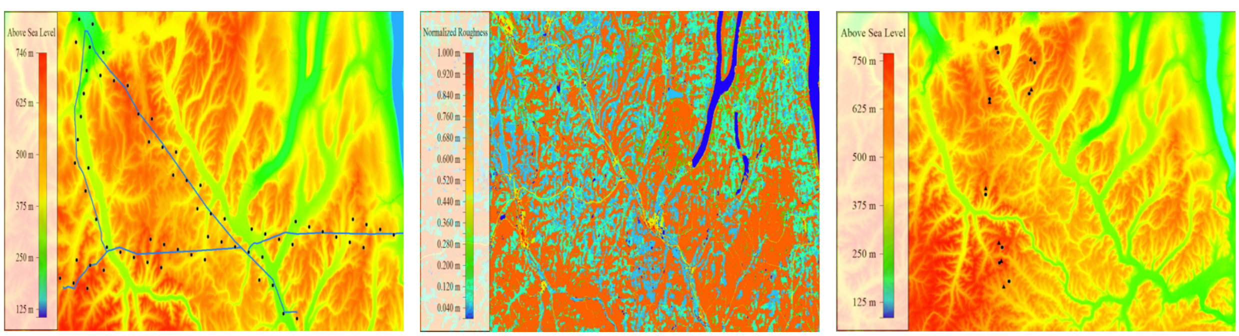
Entity	Year	Summary
PJM	2016	The study evaluated a future PJM system in 2026 with 30% of its energy sourced from renewable onshore and offshore wind and solar photovoltaic (PV). In addition to conventional transmission enhancements, they added FACTS devices on select lines higher than 100 kV. The deployment of flow control devices had an estimated annual investment cost of $81 million. However, the study demonstrated PJM region-wide savings of $890 million per year—a combination of $267 million reduction in annual transmission spending, and $623 million in production cost savings

		[94]. The authors observed that there may be further savings, such as the potential to reduce up-front interconnection costs for renewable resources.
PJM/SPP	2013	Simulating the 2016 PJM system with 13 PFC devices placed in optimal locations to reduce thermal overloads indicated an annual production cost savings of $67 million. Considering the initial investment cost of $137 million, the payback period is roughly 2 years. In the same study, EPRI looked at the SPP system and analyzed if flow control devices could defer transmission investments. In many cases these alternative technologies provided cost savings. For example, using two FACTS devices to remedy thermal overloads of an existing line would cost only between $1.5 million and $5.2 million, compared to installing a new 115-kV line at a cost of $16.8 million.
PG&E	2016	Pacific Gas and Electric Company reviewed the construction and ongoing operation and maintenance costs of Distributed Series Reactors (DSRs) as an alternative to mitigating the thermal overloading of a 230-kV line [94]. Installing approximately 2,000 DSR units on this 230-kV line at an estimated cost of $33 million indicated almost a 75% cost savings compared to reconductoring the line at an estimated cost of $130 million. The study results show 99.9% availability of these devices with a correct operating state 99.99% of the time. However, lower load projection in recent transmission planning studies, due to energy efficiency and distributed energy resources, indicates significantly lower thermal overloads and questions the need of the DSRs.
NYISO	2018	Flow control devices played a major role during the 2018 cold snap event in the northeast U.S. During this event, NYISO saw a 50–100% increase in downstate prices (in particular, Zone J: New York City, in comparison to the Western region, Zone A: West), and initiated several NERC Transmission Loading Relief alerts [94]. The two Ramapo PARs enabled NYISO to direct flows from PJM into eastern New York using its 500-kV path. NYISO has publicly acknowledged the reliability benefits that their PARs have previously provided: “The control capability provided by the two Ramapo PARs increases operational flexibility for NYISO. Power injections can be directed where needed for reliability.”

APPENDIX B **DLR Case Study**

The DLR technology used in this case study is a CFD software tool called WindSim [95]. It is based on a three-dimensional Reynolds Averaged Navier Stokes solver. Solving the non-linear transport equations for mass, momentum, and energy makes WindSim a suitable tool for simulations in both complex terrain and in situations with complex local climatology. Assessment of wind resources is accomplished with both experimental and numerical means. Typically, experimental data from a limited area is used in a numerical model to assess the wind resources within a larger area. The numerical model calculates the terrain-induced acceleration of the wind field, which can be referred to as speed-up.

The case study that is examined is a 120 km x 120 km region in southeastern New York. This region consists of nine primary lines that are considered to be dynamically rated, as well as two secondary lines to a major regional substation and five outer lines for additional overall system observation. These transmission lines are shown with the blue lines in the elevation maps in Figure 29a. The circles in Figure 29a show nearby HRRR weather model location data. Figure 29b shows the roughness of the terrain. The roughness is a measure of small-scale features within the model, where a low roughness correlates to water or low vegetation, and high levels of roughness correlate to cities or forests. In Figure 29c, the wind farm locations for the region are shown marked with triangles, and the specifications for these wind farms are detailed in Table 29. There are also solar farms co-located with three of the wind farms. These solar farms are detailed in Table 30.



(a) (b) (c)

Figure 29. Map of the region of interest, (a) shows the transmission lines of interest and nearby HRRR weather model location data, (b) shows the roughness of the terrain, and (c) shows wind farm locations for the region.

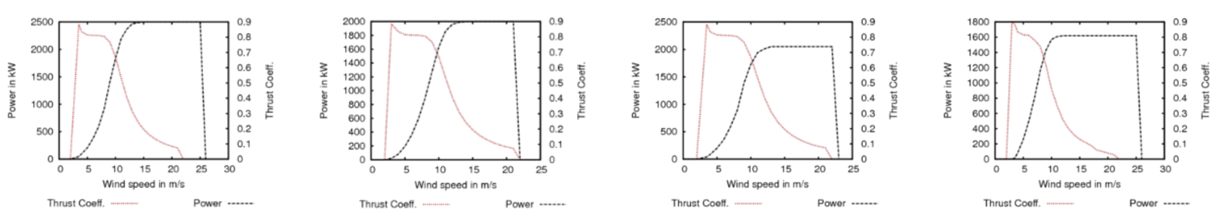
Table 29. Wind farm parameters. [PH] represents a placeholder for wind turbines that are unknown.

Plant Name	MW	Turbine	Latitude	Longitude
Canandaigua Wind	125	2.5 MW Clipper Liberty C96	42.525745	-77.4236
Baron Wind	272	[PH] 2MW Siemens-Gamesa G90	42.452591	-77.5425
Eight Point Wind	101.2	[PH] 2MW Siemens-Gamesa G90	42.211744	-77.5158
Howard Wind	55.4	2.05 MW Senvion MM92	42.304817	-77.5542
Canisteo Wind	290.7	[PH] 2MW Siemens-Gamesa G90	42.137211	-77.5017
Prattsburgh Wind	147	[PH] 2MW Siemens-Gamesa G90	42.474052	-77.4215
Marsh Hill	16.2	1.6 MW GE 1.6-103	42.18081	-77.5088

Table 30. Solar farm parameters.

Plant Name	MW	Latitude	Longitude
Morris Ridge	177	42.67503	-77.8913
Clear View	20	42.53424	-77.5228
Troupsburg	20	42.02689	-77.577

The power curves for these turbines are shown in Figure 30. The red dotted line shows the thrust coefficient, and the black line shows the power curve. These turbines all cut out at approximately 23 m/s. WindSim takes these power curves and feeds in the local weather observation data and local CFD wind fields to produce a timestamped power generation for each turbine. Since the layout of the wind farms are unknown, only one turbine is modeled and then multiplied to achieve the total power output according to Table 29.

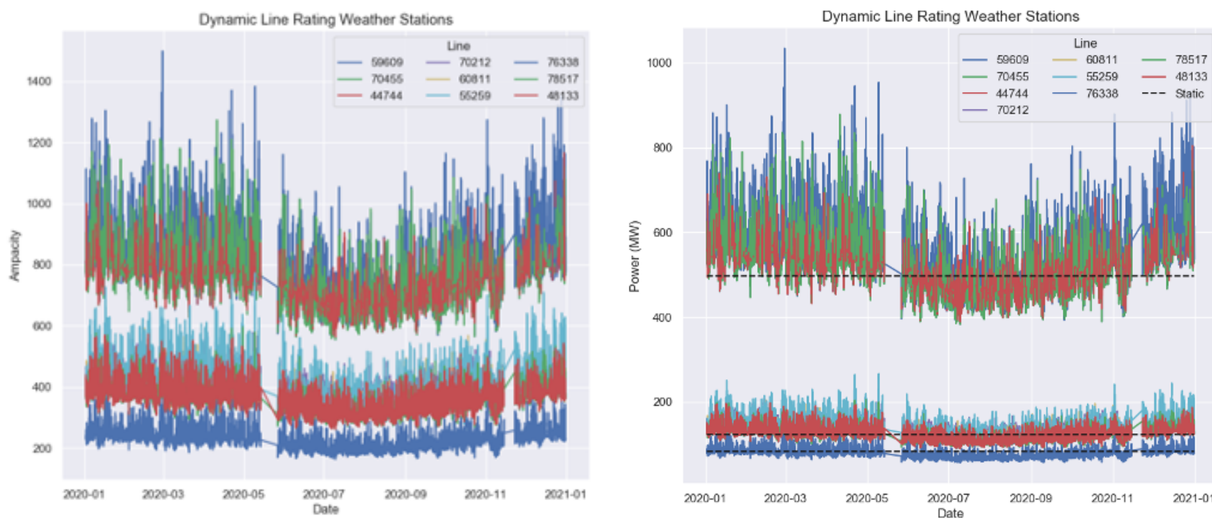


(a) (b) (c) (d)

Figure 30. Wind power curves for (a) Clipper Liberty C96, (b) Siemens-Gamesa G90, (c) Senvion MM92, and (d) GE 1.6-103.

The first steps of the DLR calculation process are to define the domain of interest for the transmission lines to be modeled, to identify the structure locations for all of the transmission lines of interest, and to find available historical weather data observations near the lines. Then, the conductor properties need to be determined, such as the type (ACSR,ACSS, etc.) and size (Drake, Pigeon, etc.), the maximum conductor temperature, the emissivity, and the absorptivity. While not necessary for DLR calculations, it can be useful to determine what the static assumptions used by the RTO are for the wind speed, wind direction, ambient temperature, and solar irradiance. This provides a baseline comparison for the improvement of using DLR methods, depicted by the horizontal dashed lines in Figure 31b.

Next, the ampacity is calculated using the weather observation data, the near-term forecast data (HRRR3), and the forecasted ampacity data (HRRR36). This is then converted into MW of power transmitted based on the voltage of each of these lines. The raw data for the ampacity is shown in Figure 31a, and the data for the power transmission is shown in Figure 31b for the weather observation data. There are a few gaps in the line ratings due to a lack of available weather station data in the region.



(a) (b)

Figure 31. The (a) raw ampacity calculation and (b) corresponding transmission power.

One issue with using forecasted DLR is that there is an error associated with the weather forecast and observation data that translates through the calculated rating. Figure 32a shows the differences from the near-term forecast to the observed data for the 230-kV lines, and Figure 32b shows the corresponding error from the day-ahead forecast to the observed data. Typically, the forecasts in this region overestimate the available transmission power, so some downrating of the forecast may be required to avoid exceeding maximum conductor temperature. For the 115-kV lines, the error is shown in Figure 32c for the near-term forecast and Figure 32d for the day-ahead forecast. The error for these smaller lines is more evenly distributed, but still tends to have overestimation biasing.

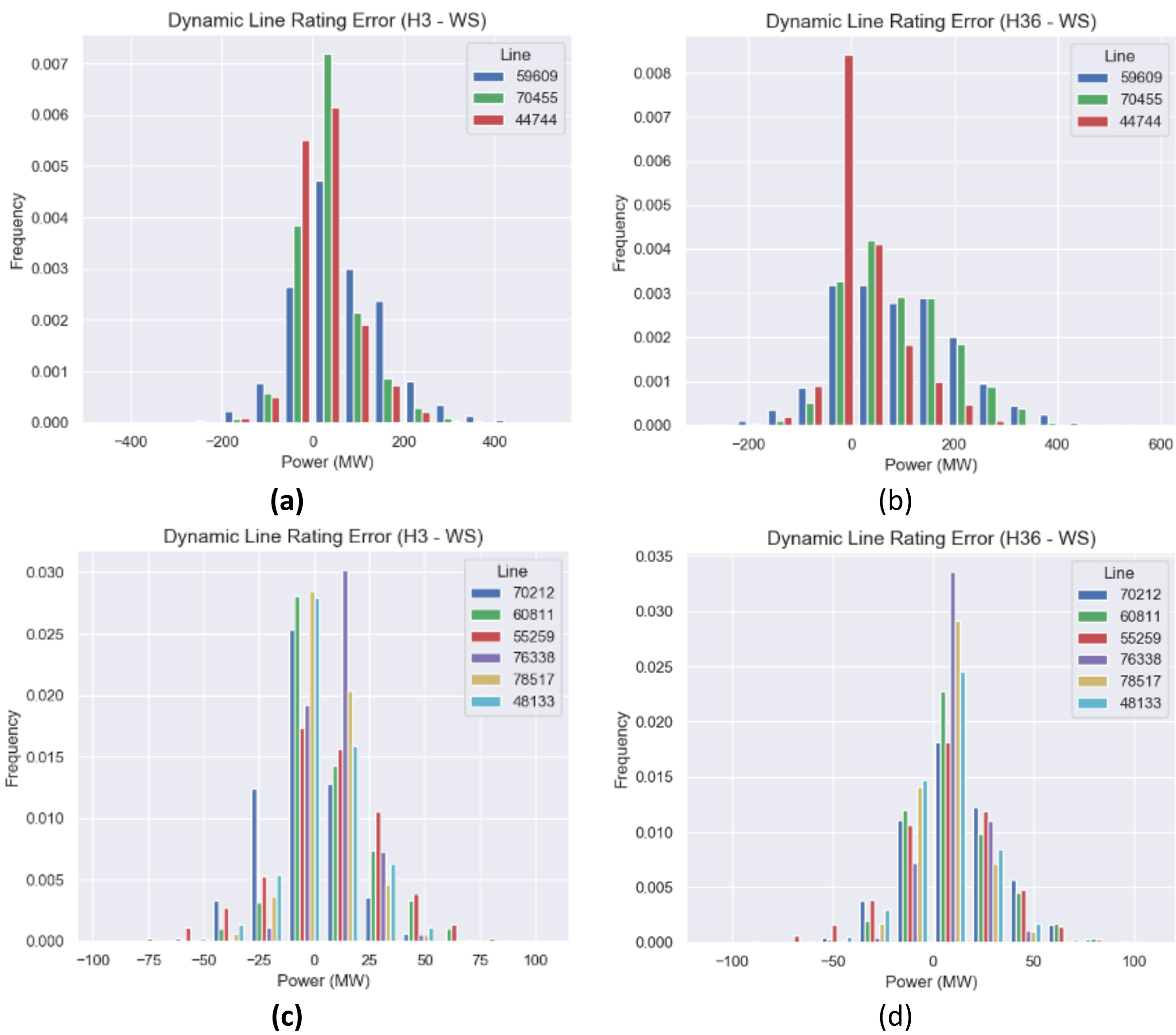


Figure 32. The (a) near-term forecast error and (b) day-ahead forecast error for the 230-kV lines, and the (c) near-term forecast error and (d) day-ahead forecast error for the 115-kV lines in the region.

APPENDIX C PFC Modeling Methodology

The modeling approach for PFCs and the calculation for changing line flows is provided in Figure 33. In PLEXOS, all PFCs, regardless of type, are represented by adding a parallel direct current (DC) line to the AC line where the PFC is added. Because PLEXOS uses a simplified, linearized DC optimal power flow (DCOPF), the inclusion of the additional DC line is a modeling approximation used to capture the behavior of PFCs without overly complicating the optimization. The rating of the parallel DC line is based on the minimum and maximum angles used to represent the PFC.

Specifying the angle of the PFC device is a technology neutral way of quantifying the total change in line flow that can occur due to the PFC. In the example below, a Distributed Static Series Compensator (DSSC) (a specific type of PFC) is modeled as an AC voltage source in series with any given line. In this example, a 5-kV device added to a 115-kV line would increase the max voltage to 120-kV. To convert this to a min and a max angle, the ratio of the new line voltage to the nominal line voltage is calculated (e.g., 1.04 degrees in this example).

In PLEXOS, the limits on the parallel DC line are computed based on the Line Reactance and Flow Control angle bounds, where $Min\ Flow = \frac{Min\ Angle \cdot 2\pi}{Reactance\ 360\ degrees\ (p.u.)}$. PLEXOS then optimizes the flow on this equivalent DC line and interprets the result as the optimal angle on the PFC [96]. The example with the 5-kV PFC on a 115-kV line translates to a 1.04-degree minimum and maximum angle for the PFC device, which would change the line rating of the 124-MW 115-kV line by 21 MW, or 16%.

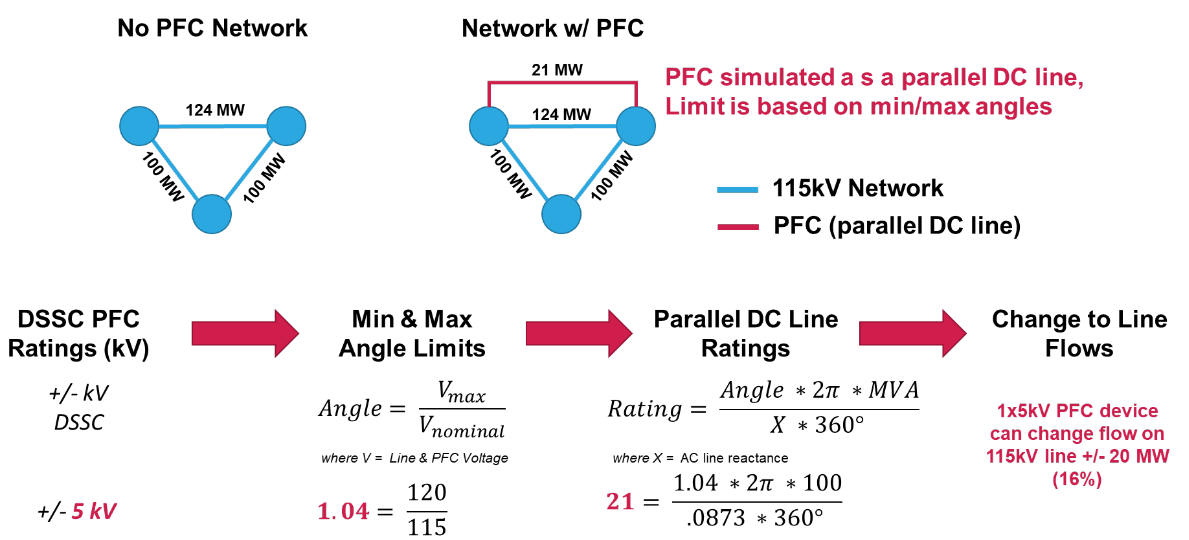


Figure 33. Modeling approach and calculating changes in line ratings due to PFCs.

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