Comments of CAC, ELPC, SUN, and Vote Solar on IURC's Study on Advanced Transmission Technologies

June 3, 2026

Introduction

Citizens Action Coalition of Indiana (CAC), Environmental Law & Policy Center (ELPC), Solar United Neighbors (SUN), and Vote Solar appreciate the opportunity to provide stakeholder comments regarding the Indiana Utility Regulatory Commission's (IURC) Study on Advanced Transmission Technologies (ATTs) ("the study") pursuant to Senate Enrolled Act (SEA) 422. As Indiana faces significant load growth driven by data centers and manufacturing, ATTs represent a critical tool for grid planners and operators to facilitate economic growth while preserving just and reasonable rates for existing customers. Specifically, Grid Enhancing Technologies (GETs) like Dynamic Line Ratings (DLR) offer a cost-effective, near-term solution for Indiana customers while the region works to expand the conventional transmission system. Our comments center on the affordability impacts of these technologies and provide recommendations for the study being initiated by the IURC and conducted by the selected respondent, Electric Power Engineers, LLC. (EPE). Our comments are supported by an independent modeling study that demonstrates the potential for GETs to save Indiana Michigan Power (I&M) customers tens of millions of dollars annually.

I. The Affordability Imperative

Affordability remains the central focus of grid planning across the country in the midst of changing generation patterns and massive load growth forecasts. GETs are already being used in many places across the US to reduce congestion costs and keep downward pressure on rates. In addition, GETs can rapidly expand the load serving capacity of the system, which, coupled with load growth, can help spread the total costs of the existing system more widely. All things being equal, increasing the utilization rate of the existing system has the potential to lower rates.[1]

The cost and speed advantages of GETs are now well documented.[2] To name just one recent example from Indiana, a 2024 dynamic line ratings demonstration project on the AES system found average capacity increases of up to 81% on 345kV lines.[3] Timely increases in capacity translate to significant system benefits that can be captured in several ways:

- **Cost-Effectiveness:** GETs are several orders of magnitude lower in cost than conventional transmission upgrades. While there is wide recognition that large conventional transmission upgrades are needed,[4] GETs can be used to capture some of the value of expanded system capacity today.
- **Risk Mitigation:** GETs serve as a low-cost "insurance" policy against delays in the construction of conventional system upgrades or unplanned grid emergencies.

[1] https://www.brattle.com/the-untapped-grid/
[2] https://inl.gov/national-security/advanced-grid-solutions/
[3] https://www.aes.com/sites/aes.com/files/2024-04/AES-LineVision-Case-Study-2024.pdf
[4] https://www.energy.gov/oe/national-transmission-needs-study

- **Interim Savings:** GETs can be used to lower costs during the construction of conventional system upgrades, which are often time-constrained based on the feasibility of taking high value lines out of service for repairs and augmentation.

The Public Utilities Commission of Ohio recently completed an analysis of Advanced Transmission Technologies that provides a good high-level overview of ATTs.[5] The report concluded that Ohio should "leverag[e] ATTs to expedite the interconnection of new loads and meet short-term needs while longer-term upgrades are developed." As discussed below, the IURC should build on the PUCO's work by conducting a specific analysis of the Indiana grid to identify locations where utilities can deploy ATTs to provide ratepayer benefits.

II. Evaluating DLR Value: Backcasting vs Forecasting

Understanding the value of GETs requires appropriate modeling methodologies and accepting that no single model can accurately calculate the full value of these technologies. Historically, GETs studies have utilized either backcasting or forecasting, both of which have distinct trade-offs:

- **Backcasting:** This method calculates the real-world savings that *could* have been captured during historic grid events had GETs been deployed. The advantage of this technique is that it can accurately capture the unique grid conditions during extreme grid events where GETs and transmission capacity more broadly provides the most system value.[6] However, the primary drawback for backcasting is that it does not show how congestion patterns may change in response to planned system upgrades. For this reason, backcasting is recommended as a necessary, but not a sufficient exercise to help calibrate and contextualize the projected savings identified in forecast modeling. A grid upgrade that could have saved tens of billions of dollars during a recent weather event is likely to have that potential to offer similar savings in the near future barring any major transmission system upgrades or load pattern shifts.
- **Forecasting:** This method shows how congestion patterns change in response to system evolution and can test a variety of scenarios, including generation connection and load growth. While forecasting methods have the advantage of being able to test a variety of scenarios and sensitivities, they also run the risk of misrepresenting reality without proper calibration against backcasting. In addition, forecasting models are highly sensitive to the input assumptions (in this case, load and generation growth assumptions). For this reason, forecasting models should explore several load and

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[5] https://dam.assets.ohio.gov/image/upload/puco.ohio.gov/empliibrary/files/OPA/Website%20files/Electricity/PUCO_ATT_Report.pdf

[6] Hanna R, Marqusee J. Designing resilient decentralized energy systems: The importance of modeling extreme events and long-duration power outages. iScience. 2021 Dec 11;25(1):103630. doi: 10.1016/j.isci.2021.103630. PMID: 35005564; PMCID: PMC8718982.

generation growth scenarios to evaluate how robust the projected savings are and contextualize those savings using recent historical records.

Neither of these methods adequately capture the optionality value of GETs, or the ability for the technology to be deployed rapidly and address grid congestion within a matter of months in response to emergency operating conditions. This value stream remains mostly a topic of industry research,[7] but it merits consideration that GETs may provide an "insurance value" not currently captured in modeling practices today.

Based on a review of the current GETs analysis state-of-the-art within our expert network, we recommend that the selected respondent's GETs study consider both a backcasting and forecasting evaluation of opportunities for GETs in Indiana. This will provide the IURC with an historical context on the scale of savings that could have been captured if the technology had been deployed in the recent past and an understanding of the range of potential savings depending on what load and generation future arrives. We also recommend that the IURC continue to accept inputs from industry research organizations and stakeholders on the emerging value streams from these rapidly evolving technologies. Recent breakthroughs in AI-based software and sensor technology is quickly upending heuristics and generally accepted boundaries on the art of the possible for grid utilization.

To illustrate the importance of multiple scenarios in forecasting studies we commissioned an independent investigation of the congestion savings potential of GETs in I&M's Indiana service territory.

III. Independent GETs Analysis of I&M's system

Recently, I&M conducted a GETs study by analyzing two production cost modeling cases using PROMOD software. The first case, Study Case #1 (2029): 2024/25 ME Base Case 2025 & 2029 (May 1, 2025 Version), showed no congestion and therefore no opportunity for GETs or DLR to offer savings. The second case, "Study Case #2 (2032): 2024/25 ME Base Case 2032 & 2035 (5.1.2025 Version)" found minimal curtailment on either renewable or conventional units (35 units curtailed for less than 10 hours in the base case, and 28 units curtailed for less than 10 hours in the DLR simulation case). Consequently, I&M found no clear indication for an application of GETs with significant benefit.

This result was surprising given that PJM's most recent Independent Market Monitor report highlighted that PJM-wide congestion costs are up 300% year over year, increasing to over $2 billion in the first quarter of 2026.[8] I&M's parent company and PJM zone, American Electric Power (AEP), saw $363.3 million of congestion charges in the first three months of 2026.

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[7] https://www.esig.energy/reports-briefs/utility-perspectives-on-making-grid-enhancing-technologies-work/

[8] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q1-som-pjm.pdf (pg. 8)

Unfortunately, the Independent Market Monitor report only delineates congestion costs by zone not by state or utility, so the congestion costs for Indiana customers specifically cannot be determined using this source. However, the scale of congestion cost growth across PJM underscores the need for a backcasting analysis of historical Locational Marginal Price nodes across the state to better determine how much Hoosiers are already paying for congestion. This effort could help contextualize the results of future forecast studies like the one being undertaken by EPE.

There could be a variety of reasons for PJM congestion costs to be spiking while future forecast models for I&M show little/no congestion savings opportunities by using DLR. Unlike other parts of PJM, I&M has access to a robust 765kV network, so it is possible that the area remains insulated from the congestion cost growth facing the rest of the PJM region. In addition, the study cases used by I&M were developed in early 2025, and may not have incorporated some of the rapid load growth that was seen in PJM through 2025. Finally, as discussed earlier, production cost models often fall short in valuing the true congestion cost savings that are captured during emergency conditions and extreme weather events such as Winter Storm Iona, which struck the upper midwest and mid-Atlantic in mid-March 2026.

III.a. Discussion on the Methodology:

To provide a different look at the potential future congestion in I&M and the value of GETs in northern Indiana, GridLab commissioned an independent grid modeling firm, Ulteig Engineers, Inc., to conduct an informational scenario analysis using production cost modeling tool PLEXOS. GridLab asked Ulteig to model a scenario that added a new large load customer and several inverter-based resources to I&M's northern Indiana service territory in order to estimate the scale of congestion savings that GETs, including DLR, could provide. This indicative scenario was intended to illustrate the potential benefits under a more aggressive load and generation growth outlook, compared with the more modest assumptions used by I&M.

Calculating the capacity of a transmission line is a combination of structural and electrical engineering practice based on the National Electric Safety Code and IEEE standard 738[9]. Utility engineers use assumptions that are documented in their Facilities Ratings Methodologies, which are typically not available publicly nor under a non-disclosure agreement. As a result, third party researchers need to make a generalized assumption around the capacity increase that could be achievable on a percentage basis rather than a more robust line-by-line assessment. The IURC should consider reducing this access limitation to allow independent researchers and public universities to perform independent analyses of line capacity increase

[9] https://standards.ieee.org/ieee/738/10207/

opportunities. Nevertheless, for the purposes of this study, recent case studies were used as a benchmark, and a single capacity increase percentage (30%) was assumed.[10]

III.b. Results:

By simulating a 30% improvement in line ratings, the study demonstrated that GETs could unlock massive value for I&M customers:

- The analysis found tens of millions of dollars in annual congestion savings.
- These congestion savings are well above the typical deployment costs of a DLR program.
- For the large load site, DLR caused a significant reduction in congestion costs.

These results suggest that there may be much more value to GETs implementation than what was identified in the I&M study and that further future scenarios should be evaluated to properly identify the opportunity for GETs to save customers money. These findings align with real-world examples where DLR has had incredible impacts on congestion savings. In one case, PPL reported an estimated $65 million per year reduction in congestion costs on a single line and avoided approximately $50 million in capital expenditures by delaying new transmission construction.[11]

IV. Recommendations for the IURC: Data Transparency and Promoting Best Practices

The spikes in congestion costs in PJM, combined with the significant difference in results between the I&M study and the indicative scenario study, underscore the importance of looking at grid congestion mitigation strategies in a variety of ways. In addition to completing a backcasting and forecasting analysis there are emerging practices that should be incorporated into future GETs studies in Indiana.

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[10] For the purposes of this study, DLR was considered the primary technology that could be used to quickly increase line capacity dynamically up to 30%, which was based on evidence from recent successful deployments provided in Appendix A. "However, in the event that specific line design constraints limit the viability of DLR, this capacity increase could also potentially be achieved with a combination of other Grid Enhancing Technologies including emissivity line coatings, targeted structure replacement, and tower raising. These design investigations were beyond the scope of this study"

[11] Unlocking Transmission Efficiency through Grid Enhancement Solutions. Arent, D. et al (2026) https://www.energypolicy.columbia.edu/wp-content/uploads/2026/03/Unlocking-transmission-efficiency-CGEP_WhitePaper_033126.pdf

IV.a. Transmission Data Transparency

The first step of a more robust GETs analysis is to provide greater transparency around the assumptions and modeling techniques that drive the capacity ratings of transmission infrastructure. Most of this information is not publicly available, and it makes it nearly impossible for regulators to evaluate if the current system is being used to its full capacity. Indiana transmission owners should, if they have not already, share their facilities ratings methodologies with EPE and provide insights into their design constraints.

We recommend that the IURC require Indiana Transmission Owners to transparently share:

- Facility Ratings Methodologies in accordance with NERC Reliability Standard FAC-008
- Standard Right-of-Way (ROW) Widths by structure type and voltage class
- Standard pole heights and phase spacing by voltage class
- Powerflow Models representing typically congested periods (e.g. "Peak Load," "High Generation, Low Load" etc.)
- Production Cost Models representing a variety of near-term future scenarios (rapid load growth, rapid generation growth, etc.)
- Approved equipment/conductor catalogues

Additionally, the IURC should require EPE to consider and incorporate the current state-of-the-art GETs evaluation practices from a variety of sources to build a repeatable study framework for utilities.

IV.b. Current State-of-the-Art Practices for GETs Studies:

Weather Forecasting

Dynamic Line Ratings require weather forecasting data to ensure that the ratings used in transmission planning studies are established and updated in a way that is safe and well documented. There are several vendors offering tools to help Transmission Planners do this, but the National Lab of the Rockies DLR has produced a robust weather dataset[12] and open-source python package[13] that can quickly allow engineers to generate a 7-year historical time series of hourly weather inputs needed to calculate the rating for any line in the contiguous U.S. This toolkit can be combined with the characteristics of the line (conductor type and maximum operating temperature) to quickly estimate the actual gains that could be captured on specific lines in Indiana.

Improved Modeling of Advanced Powerflow Controllers and Topology Optimization

DLRs are often the first technology to be evaluated in a GETs analysis, but Advanced Powerflow Controllers and Topology Optimization also offer opportunities to lower the cost of grid expansion. The difficulty is that these tools require more advanced modeling techniques

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[12] https://docs.nlr.gov/docs/fy25osti/91599.pdf
[13] https://github.com/NREL/DynamicLineRatings

than are conventionally used at many Transmission Owners. Transmission owners should develop a methodology to robustly test all emerging technologies for their capability to cost-effectively increase transmission system capacity. Fortunately, there is a growing body of work that provides practitioners with information they need to build out a GETs evaluation algorithm that works with their unique system and processes. A few selected resources are provided below.

A Guide to Case Studies of Grid Enhancing Technologies. (2022). INL. https://inl.gov/content/uploads/2023/03/A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf

Playbook: Grid Enhancing Technologies. WATT Coalition. https://watt-transmission.org/playbook-grid-enhancing-technologies/

Assessment and Evaluation of Grid Enhancing Technologies (GETs). (2025). Prepared for ACORE by EPE. https://acore.org/wp-content/uploads/2025/02/Assesment-and-Evaluation-of-Grid-Enhancing-Technologies-GETs-Report.pdf

Advanced Transmission Technologies Planning Guide. (2025). Prepared for RMI by Quanta Technology. https://watt-transmission.org/wp-content/uploads/2025/12/Quanta-Technology-Report-Advanced-Transmission-Technologies-Planning-Guide.pdf

Operations

A common barrier to wider GETs adoption is the real challenge of integrating dynamic line ratings into real-time operations. This issue is being overcome in the various Independent System Operators that manage the transmission system in Indiana, but it is also worth noting that over the past decade Idaho National Laboratory developed a "General Line Ampacity State Solver (GLASS)" software tool[14] aimed at this exact barrier. The software has robust documentation and is now commercially available.[15]

Conclusion

Grid enhancing technologies like DLR offer a proven, cost-effective method to integrate new loads, ease congestion, and maintain grid affordability without the lengthy timelines associated with traditional infrastructure builds. We appreciate the Commission's dedication to evaluating ATTs and strongly urge the promotion of standard evaluation frameworks to secure these benefits for Indiana ratepayers.

[14] https://inlsoftware.inl.gov/product/glass
[15] https://www.energy.gov/technologycommercialization/articles/windsim-power-commercializes-glass-dynamic-line-rating

ATTACHMENT

An Assessment of the Potential Value of Dynamic Line Rating on the Indiana Michigan Power (An AEP Subsidiary) System

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ACRONYMS & ABBREVIATIONS

%	Percent
AEP	American Electric Power
AI	Artificial Intelligence
DLR	Dynamic Line Rating
EIC	Eastern Area Interconnection
ERCOT	Electric Reliability Council of Texas
FTR	Financial Transmission Rights
GET	Grid Enhancing Technology
I&M	Indiana Michigan Power Company
IRP	Integrated Resource Plan
ISO	Independent System Operator
kV	Kilovolt
LMP	Locational Marginal Price
MISO	Midcontinent Independent System Operation
NLR	National Laboratory of the Rockies
Oncor	Oncor Electric Delivery Company
PJM	Pennsylvania-New Jersy-Maryland Interconnection
PPL	Pennsylvania Power and Light Electric Utilities
SCED	Security Constrained Economic
SCUC	Security Constrained Unit Commitment
SLR	Standard Line Rating
Ulteig	Ulteig Engineers, Inc.

Executive Summary

Dynamic Line Rating (DLR) is a form of grid enhancing technology (GET) that is already playing an important role in helping to evolve the United States electric grid. DLR seeks to use monitoring equipment with associated predictive analysis to provide an estimate of true real-time transmission capacity. This is relative to traditional static transmission ratings, which are often only adjusted seasonally. Increased demand from new hyperscale loads, primarily associated with artificial intelligence (AI) data centers, and ongoing age-based fleet retirements are leading to expanded renewable generation, natural gas generation, and storage deployment. These new capacity and load additions are putting pressure on the existing transmission system.

The physical expansion of the transmission grid often requires substantial investment. Permitting, engineering, procurement, and construction may have long completion timelines and significant legal risks. Even smaller options, such as reconductoring, can require large capital expenditures and procurement challenges. In this regard, DLR may provide a faster and lower cost alternative relative to physically modifying the transmission system.

The analysis contained in this report provides illustrative demonstrations of the value of DLR for the Indiana Michigan Power Company (I&M), a subsidiary of American Electric Power (AEP). The standard industry software, PLEXOS®, was used to model relevant sections of the Eastern Area Interconnection (EIC) associated with I&M and neighboring systems. Specifically, the nodal market modeling capabilities of PLEXOS® were used to predict locational marginal prices (LMPs) and curtailment risk for theoretical interconnecting loads and generation. Two specific case studies were prepared that helped demonstrate the value and flexibility of DLR based alternatives.

Model results showed that DLR provided significant value for both new interconnecting generation and loads. Total annual savings were well within the millions of dollars; however, it is important to note that these results are based on forward projections of load and generation addition that may/may not materialize. Upgrades, such as DLR, would likely be needed before allowing interconnection and operation of these loads and resources.

This analysis demonstrates that DLR can be an important tool regarding the incorporation of new renewable generation, thermal generation, loads, and storage. DLR is most valuable when transmission congestion and curtailment are primarily attributed to a limited number of binding constraints. These constraints are often created by new interconnecting resources or loads adding stress to the existing system. While DLR does not provide the 24 hour/365 day capacity increases gained from traditional transmission upgrades, like reconductoring and expansion, it may lead to significantly reduced interconnection costs, especially in the interim while long-range transmission upgrades are constructed. Given concerns about rising cost of service, DLR can provide potential cost savings that partially help resolve utility and stakeholder concerns. The analysis contained in this report was not intended to second-guess previous findings from I&M that showed DLR may have limited value for their established transmission network, but instead was aimed at supplementing those findings by looking at additional future scenarios. The addition of new concentrated load centers and the potential replacement of aging, localized thermal facilities with more distributed solar, natural gas, and storage resources may benefit from the deployment of DLR. In this regard, DLR represents a potential cost justified tool that should be an option for consideration in utility resource planning.

Introduction

Hyperscale loads, often associated with AI data centers, increased renewable penetration, and supply constraints on traditional thermal resources, are changing the ways utilities manage their demand and generation. This rapid growth is challenging utilities to reevaluate the methods available to reliably serve increasing load requirements and intermittent resources. As utilities perform and update their Integrated Resource Plans (IRPs), they are increasingly looking for new technologies and alternatives to mitigate rising customer costs.

The use of DLR provides a potentially faster, lower cost alternative or interim solution relative to new transmission construction and reconductoring. Using real-time operating conditions, DLR can access additional transmission capability on the line rather than using conservative static ratings. This may help avoid lengthy engineering, procurement, construction and commissioning phases associated with transmission projects. While DLR technology has been available for years, the relatively fast implementation times and cost benefits potentially provide a novel way to mitigate data center and generation interconnection challenges while helping to reduce customer cost of service.

DLR is often a lower cost alternative because it increases the capacity of existing lines through real-time monitoring rather than requiring new construction or major physical upgrades. The installations can often be done in a matter of weeks, without triggering permitting. By improving the efficiency of existing assets, utilities can reduce congestion and the associated costs, defer capital spending, and delay the implementation of major physical upgrades. DLR may offer the greatest advantages when transmission congestion and curtailment risk are driven by a limited number of transmission binding constraints, particularly where the value of transmission reconstruction or new construction is tied to specific interconnecting loads or resources.

The value of DLR is already being utilized. Pennsylvania Power and Light Electric Utilities (PPL) was one of the first US electric utilities to integrate DLR technology into its transmission system. Beginning in October 2022, the utility installed DLR sensors on three congested 230 kV transmission lines and found that the actual line capacity was approximately 16% higher than the static line ratings (SLR) [1]. This additional capacity improved utilization of existing assets, reduced congestion, and deferred the need for infrastructure upgrades. PPL reported an estimated $65 million per year reduction in congestion costs on one line, and approximately $50 million in avoided capital expenditure by delaying new transmission construction.

Similarly, the U.S. Department of Energy case study on Oncor Electric Delivery Company's (Oncor) found that DLR created measurable cost savings by reducing transmission congestion in Electric Reliability Council of Texas (ERCOT) [2]. The study found that a 5% increase in line capacity could reduce congestion costs by up to 60%. In some cases, a 10% increase could nearly eliminate congestion on some constrained lines. Based on ERCOT market data, Oncor estimated that a more comprehensive rollout of DLR across the system could save approximately $20 million annually. This is equivalent to about a 3% reduction in total congestion costs. These savings remain even under conservative assumptions, where Oncor limits the capacity increase of the static rating to 125% compared to the approximately 133% capacity available. Overall, the results demonstrate that DLR can deliver substantial cost savings while also helping to defer or reduce the need for more expensive transmission expansion projects.

National Grid's deployment of DLR in western New York also demonstrates the value of fully utilizing existing assets before pursuing major capital projects. According to National Grid and LineVision, DLR equipment was installed on four 115 kV transmission lines and resulted in average line capacity increases of more than 30% [3]. The project improved system flexibility, reduced renewable energy curtailment, and increased the transfer capacity of existing infrastructure, helping to defer the need for transmission upgrades. Additionally, by utilizing DLR, National Grid reducing renewable curtailments by approximately 350 MW and saving customers approximately $46 million in avoided or deferred rebuild costs [4].

The 30% DLR rating increase assumption used by Ulteig was based on observed results from deployments in comparable regions and prior industry case studies. It is noted that DLRs are time dependent and subject to ambient and operational conditions. In this regard, the improvements from this analysis may deviate from actual operating conditions. For formal project evaluations, site specific measurements are typically required to fully assess the value of DLR. This analysis does not seek to quantify specific percentage change thresholds where DLR becomes impactful. If specific line design constraints limit the viability of DLR, additional capacity increase could potentially be achieved with a combination of other Grid Enhancing Technologies including emissivity line coatings (such as Prysmian, E3X, or AssetCool), targeted structure replacement, and tower raising. These design investigations were beyond the scope of this study.

Pennsylvania-New Jersy-Maryland Interconnection (PJM) and American Electric Power (AEP) have reached similar conclusions regarding the value of DLR technology. PJM evaluated the application of DLR on a heavily congested transmission line constraint and found that replacing static transmission line ratings with dynamically calculated ratings based on real-time and historical weather conditions reduced congestion and lowered the total system congestion payments by over $4.2 million per year, based on PJM's modeling of a congested AEP transmission line using DLR technology [5]. This analysis demonstrated that DLR can deliver measurable customer savings by increasing transfer capability on existing lines, thus lowering the need for costly transmission upgrades [5,6]. These case studies demonstrate that DLR can serve as a cost-effective relatively fast solution compared to new construction or extensive line reconductoring [6,7]. Traditional transmission upgrades often require substantial capital investment and long planning, siting, and construction lead times, whereas DLR can often be implemented more quickly and at a lower cost by unlocking unused capacity on existing transmission assets. As renewable generation alternatives and large hyperscale loads seek to interconnect to the grid quickly, DLR provides a critical new tool for improving grid flexibility and addressing congestion challenges.

To assess the potential value of DLR on the I&M system, Ulteig utilized the nodal market simulation features of PLEXOS®. PLEXOS® is a standard industry tool used by AEP and many other utilities for modeling ranging from IRPs to financial transmission rights (FTRs) assessment. Specifically, the benchmarked Eastern Area Interconnection (EIC) model from Energy Exemplar was used to model the I&M and relevant neighboring systems. The results of this analysis demonstrate the potential value of DLR on the I&M system for speculative interconnecting loads and resources. It seeks to provide illustrative examples that show DLR can be a useful tool when evaluating interconnection and operation needs.

The analysis within this report is supplementary with findings recently developed by I&M. Recent modeling reported by I&M showed that for their system, as it largely exists today for specific planning cases, there may be limited application of DLR. Along with this, transmission upgrades for the PJM system within and near the I&M service territory, and on the Midcontinent Independent System Operation (MISO) side of the MISO-PJM seam, have significantly improved the robustness of the local transmission system.

Ulteig's views its own analysis as complementary to the I&M findings. Rather than assessing the current value of DLR on the I&M system as it exists today, Ulteig seeks to demonstrate DLR future value for new interconnecting loads and resources. The Ulteig model used security constrained economic dispatch (SCED) and security constrained unit commitment (SCUC) to ensure a realistic impact analysis. Also, relevant recently approved PJM transmission projects were incorporated into the model.

In addition, DLR may have an impact on other types of modeling performed for the I&M system. As an example, the recent I&M IRP may have incorporated the cost of potential transmission upgrades associated with wind generation and other alternatives into the total capital expenditure. Transmission can be a significant cost within the assumed capital expenditures for a given resource. In this regard, the potential of DLR to reduce costs and increase speed to power for a given subset of projects may improve total customer value.

Analysis Methodology

To evaluate the value of DLR on I&M's system, it was necessary to study potential generation and load interconnection points. As a first step, PowerGem TARA was run to determine the transmission headroom of substations across the I&M network for 138 kV and above. Based upon standard Independent System Operator (ISO) evaluation methodology, the room on these substations was identified, along with relevant contingencies and monitored elements.

Next, a baseline power market simulation was established. Specifically, the PLEXOS® 2025 EIC model was used as a starting point. All simulations used the study year of 2029. To fairly assess the value of DLR, the model was updated to include recent confirmed changes regarding system transmission topology and generation interconnection queue for relevant areas of the PJM and neighboring MISO systems. Given the size of the EIC model, it was necessary to restrict the model to a relevant subsystem of MISO and PJM. Kron-Reduction was used and included the entirety of AEP system in PJM along with neighboring zones in PJM near I&M. In addition, Commonwealth Edison Company and MISO Zones 6 & 7 were included.

The model used SCED and SCUC to more accurately simulate the power market. This analysis accounts for relevant contingencies that the model must respect in terms of an iterative commitment and dispatch analysis. SCED and SCUC based modeling is computationally intensive; including too many contingencies can lead to both infeasibilities and unacceptable runtimes. To avoid these issues, the relevant contingencies and monitored elements from the

PowerGem TARA simulations were used within this analysis rather than all possible contingencies and monitored elements defined within the interconnection. Future work could include more extreme system conditions to better understand the additional value that DLR or other technologies could bring to I&M's system during rare, but often expensive, grid operating conditions.

Ulteig's baseline power simulation forecasted a congestion profile for the study nodes of interest. This comparison point was used to ensure reasonable model behavior as resources and loads were added to the model. Four solar facilities and one large scale load were connected to five different power nodes; these nodes were selected based upon PowerGEM TARA analysis to study transmission headroom (See Figures 1 and 2). Within PLEXOS®, the utilized solar profiles were developed and benchmarked by Energy Exemplar. These profiles were developed from standard models, such as System Advisor Model (SAM), and historical data from the National Laboratory of the Rockies (NLR). The added load was assumed to be uninterruptible and continuous to reflect potential worst case steady-state operating conditions for a data center. Each solar facility had an assumed installed capacity rating of 850 MW; the load was assumed to be 650 MW and uninterruptible.

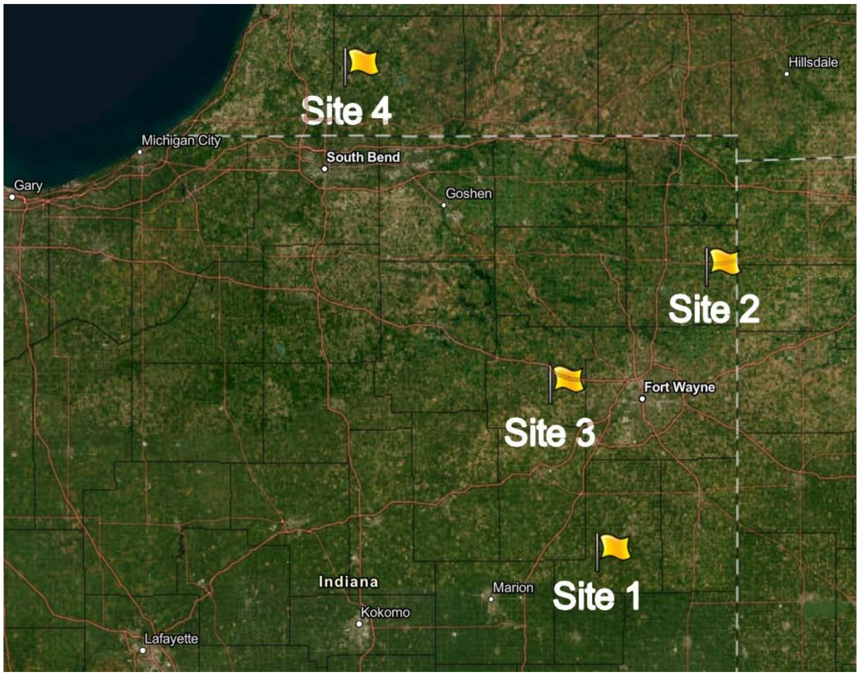

Figure 1: Generation Site Map

Figure 2: Load Site Map

This analysis then considered the impact of DLR on transmission congestion by forecasting the congestion at the hourly level with the static rating and then with an improved dynamic line rating for the relevant binding constraints. The analysis used a 30% improvement in line rating, which is in rough alignment with estimates from comparable DLR studies in Indiana and nearby regions during summer conditions [3, 7]. The hourly congestion was then used to calculate the impact on power sales or purchases in terms of total cost impact.

It should be noted that this analysis is a snapshot-in-time and based upon a specific transmission topology. Changes to the I&M and surrounding systems may affect results. In addition, the study sites are based upon transmission analysis only, rather than dedicated siting studies which must consider parameters such as land availability, permitting, and resource adequacy. Additional statistical risks, such as generator forced outages, were not considered.

Model Findings

The results of the DLR improvement analysis are shown for each specific site below. As expected, improvement impact differed between sites based upon the overall robustness of the surrounding transmission network. For each site, the congestion was often primarily due to 2-3 lines. These lines are the best candidates for DLR deployment. The solar generation sites are shown first with the congestion impact change quantified. Next, the impact on the load site is detailed.

It should be noted that some of the hourly congestion costs as forecasted by PLEXOS® far exceeded the values shown in these graphs. These excessively large estimates were modified to partially reflect potential market caps on shadow pricing which provides some insulation to extreme hourly values in terms of actual market settlements. These changes help ensure the value of DLR is not overstated.

This analysis does not seek to account for practical market requirements that would prohibit these study resources from interconnecting due to the large operational and financial risks. As mentioned, these results for DLR congestion improvement should be viewed as illustrative rather than providing a definitive market value assessment. Specifically, the modeled hourly, monthly, and annual savings should not be taken necessarily as realized accounting savings.

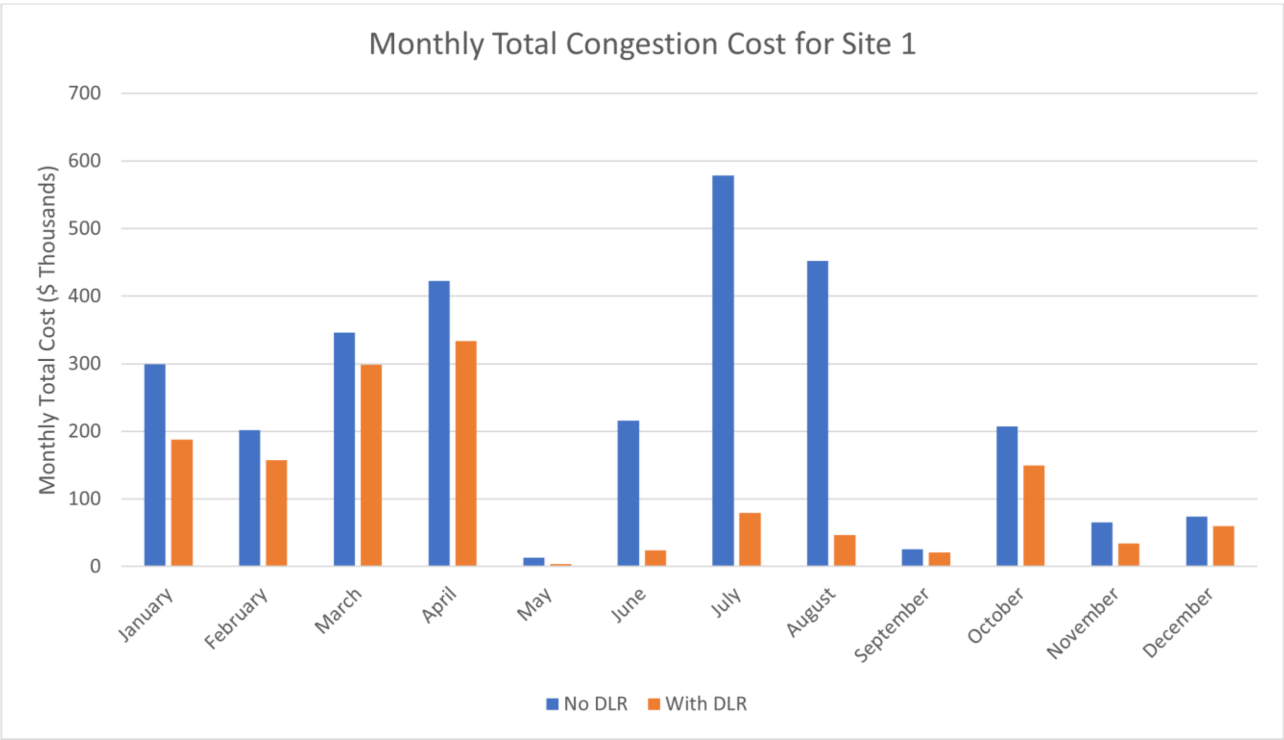

Figure 3: Generation Site 1 Monthly Congestion Cost, 850 MW Installed Capacity

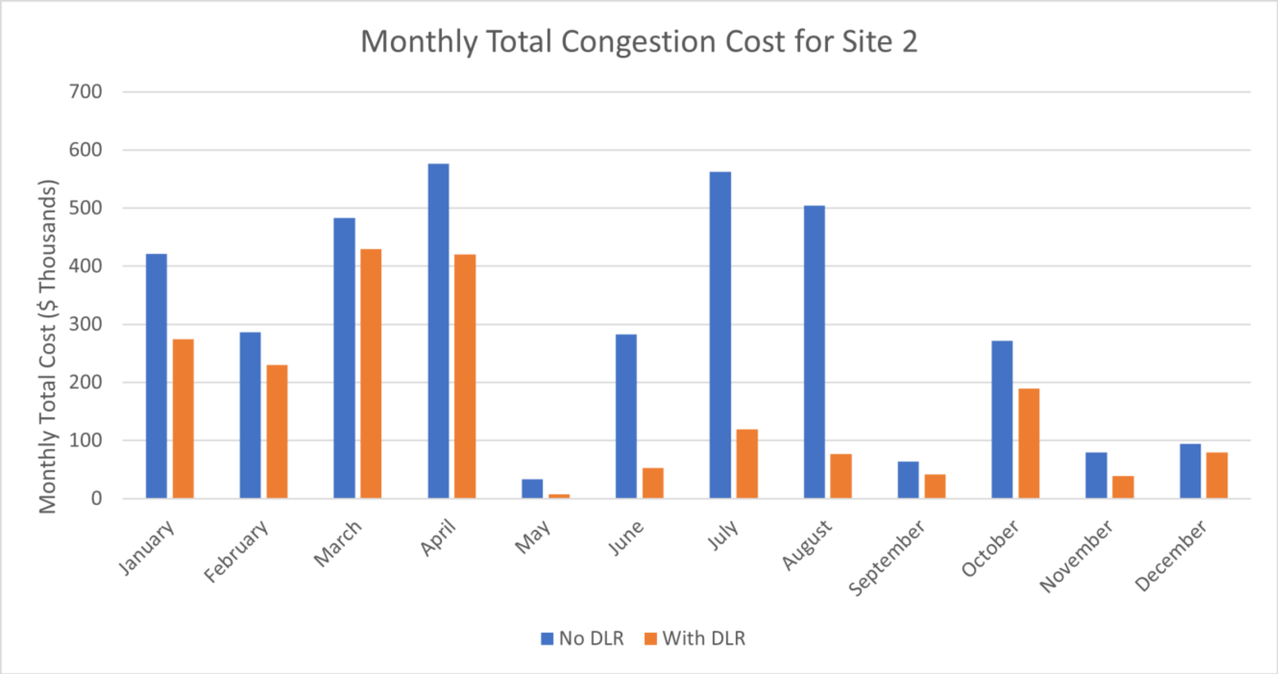

Figure 4: Generation Site 2 Monthly Congestion Cost, 850 MW Installed Capacity

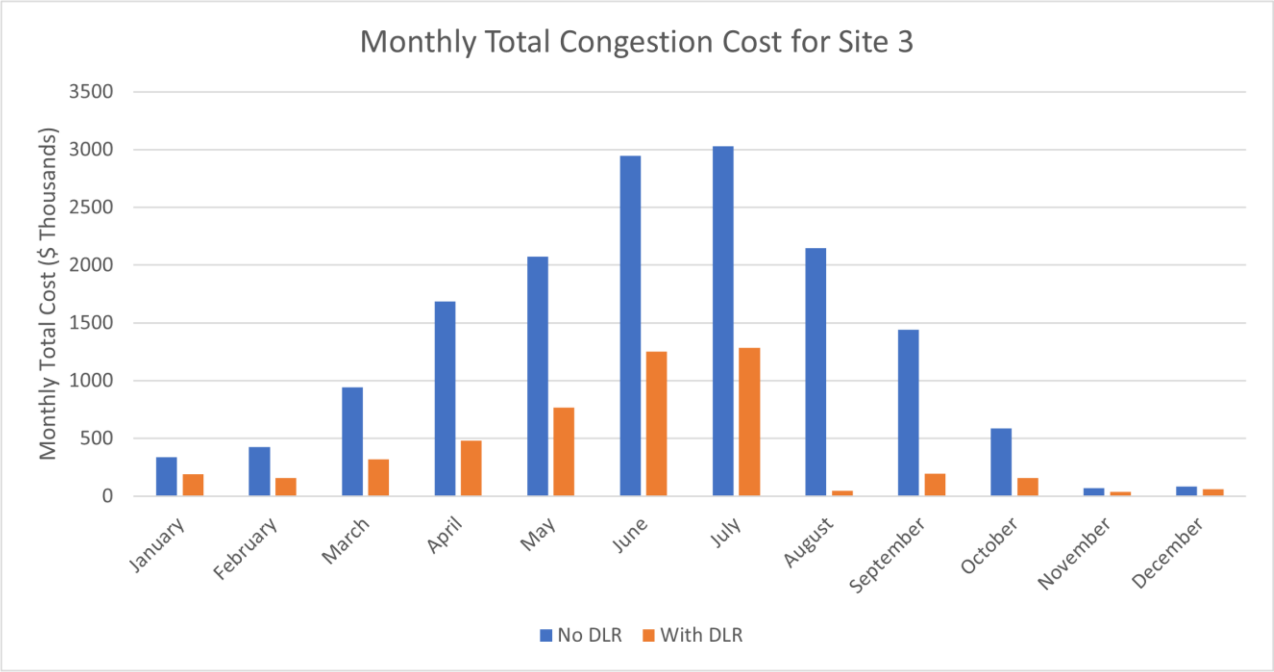

Figure 5: Generation Site 3 Monthly Congestion Cost, 850 MW Installed Capacity

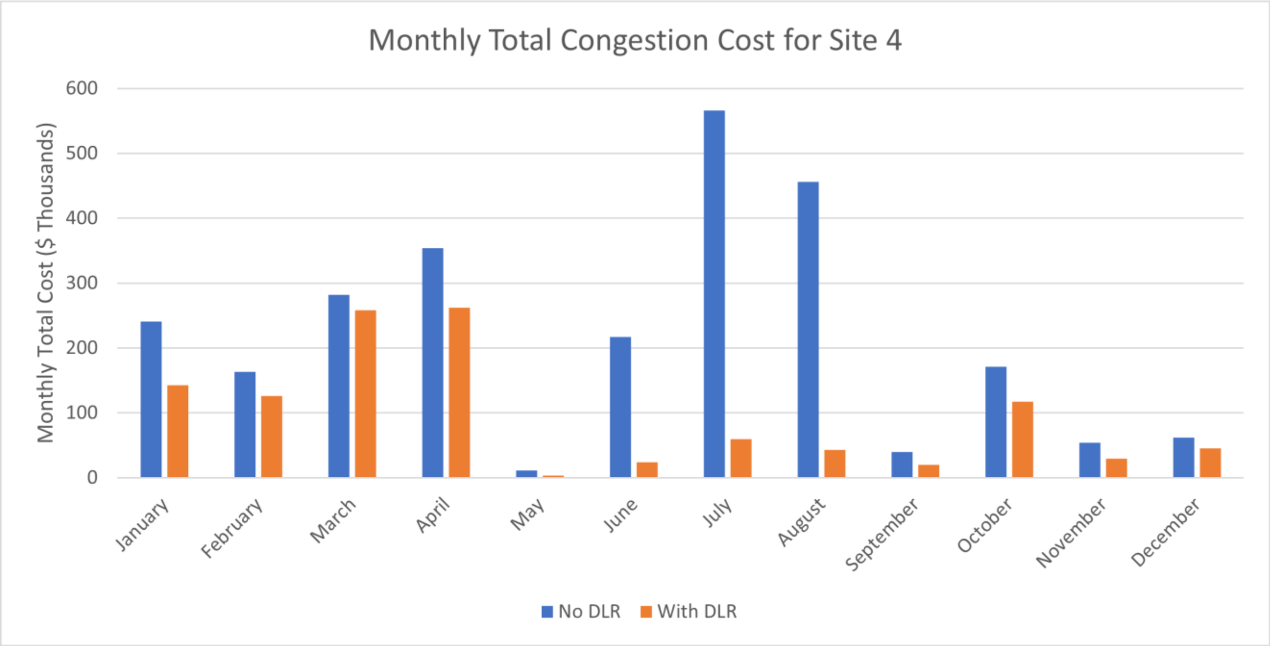

Figure 6: Generation Site 4 Monthly Congestion Cost, 850 MW Installed Capacity

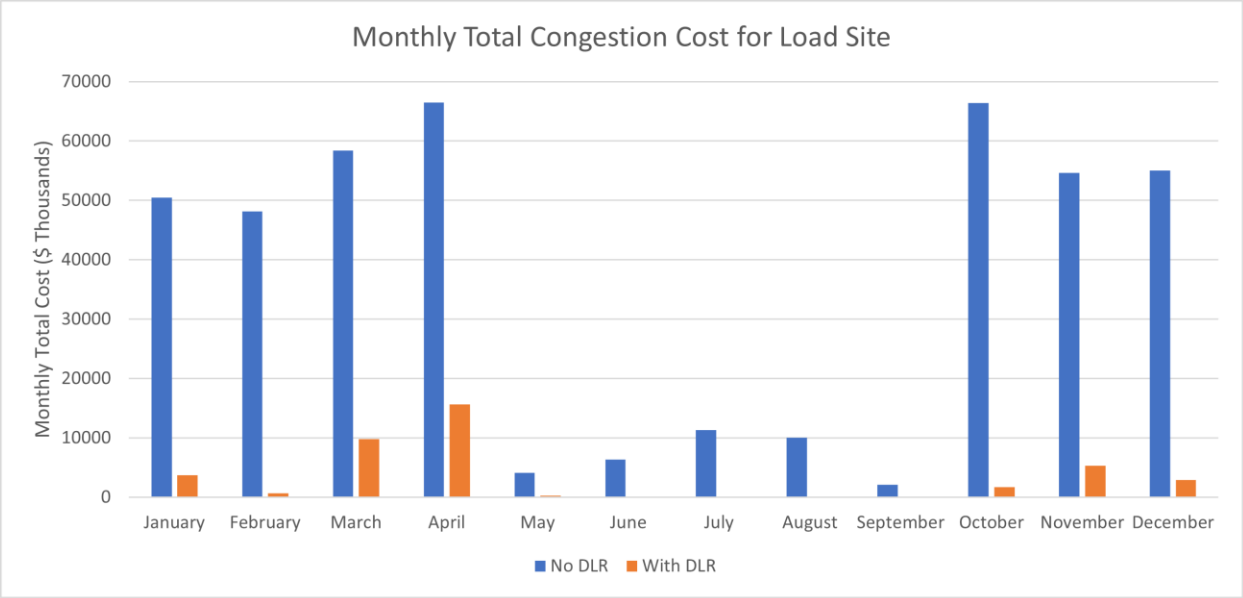

Figure 7: Load Site Monthly Congestion Cost, 650 MW of Uninterruptible Load

As seen from the figures above, the DLRs resulted a significant reduction in the congestion cost associated with each site. The congestion change was often primarily associated with a limited number of lines and hours per site, which is indicative of a grid constraint that could be quickly mitigated with an option like DLR.

Both transmission congestion and resource/load curtailment risk can originate due to transmission binding constraints, with curtailment typically regarded as a more severe impact. In addition, curtailment can occur due to a mismatch between generation and load. In this study, no curtailment was observed for the system study additions. Given ongoing need for new generation and the faster deployment of DLR compared with conventional transmission expansion, these results suggest that DLR can be a valuable tool to accelerate the connection of new large loads.

Conclusion

This analysis demonstrates the value of DLR for new load and generation interconnections on the I&M system, including renewable generation, thermal generation, storage, and large loads. DLR is most effective when congestion and curtailment risk are driven by a small number of transmission binding constraints created by new interconnecting resources or loads. Although DLR is not a replacement for traditional transmission upgrades such as reconductoring or expansion, it can reduce interconnection costs and shorten timelines. It can also serve as an early component of a broader transmission strategy by helping bring new customers online while larger infrastructure investments are planned and built. Given concerns about rising cost of service, DLR offers potential savings that may help address utility and stakeholder concerns. Overall, this analysis shows that DLR is a practical tool utilities can use to support interconnections and improve system operations.

Appendix A. References

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[2] U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability (2014, May). *Oncor's Pioneering Transmission Dynamic Line Rating (DLR) Demonstration Lays Foundation for Follow-On Deployments*, 5-7.

[3] National Grid & LineVision joint press release, PR Newswire. (2022, October 20). *National Grid and LineVision Deploy Largest Dynamic Line Rating Project in the United States.* https://www.prnewswire.com/news-releases/national-grid-and-linevision-deploy-largest-dynamic-line-rating-project-in-the-united-states-301653906.html, accessed April 2026.

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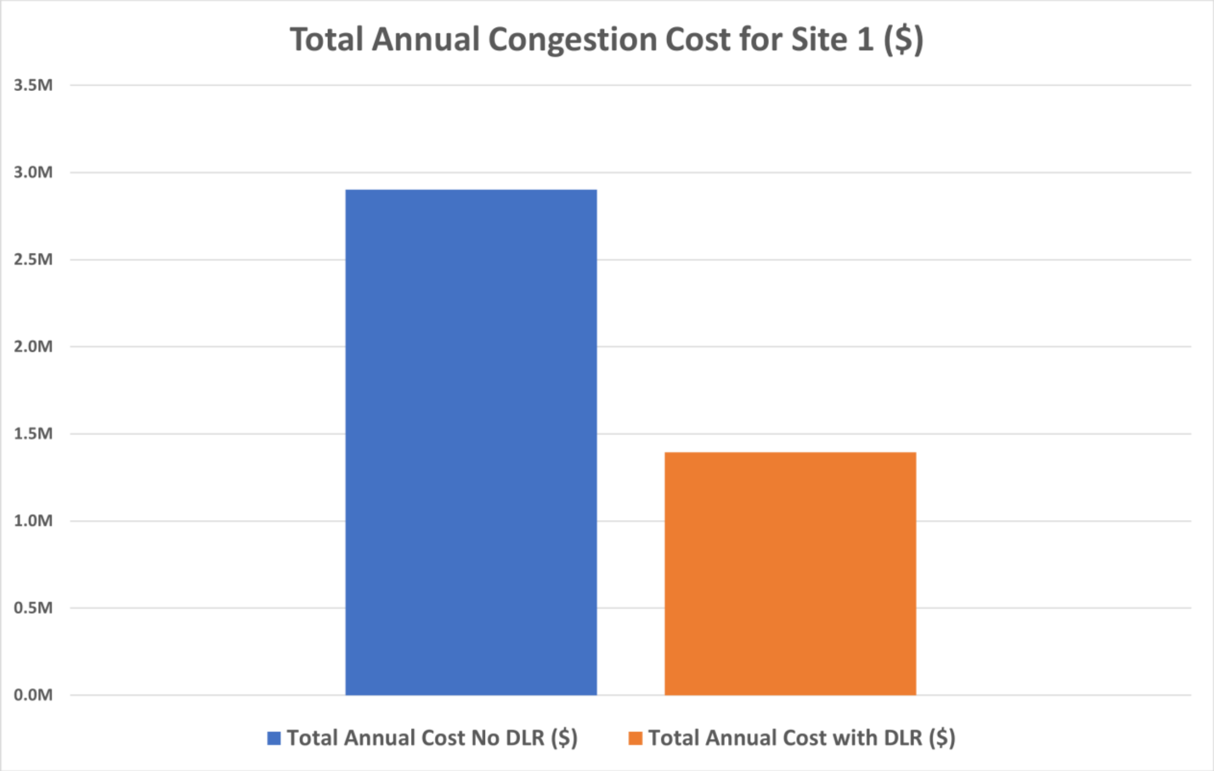
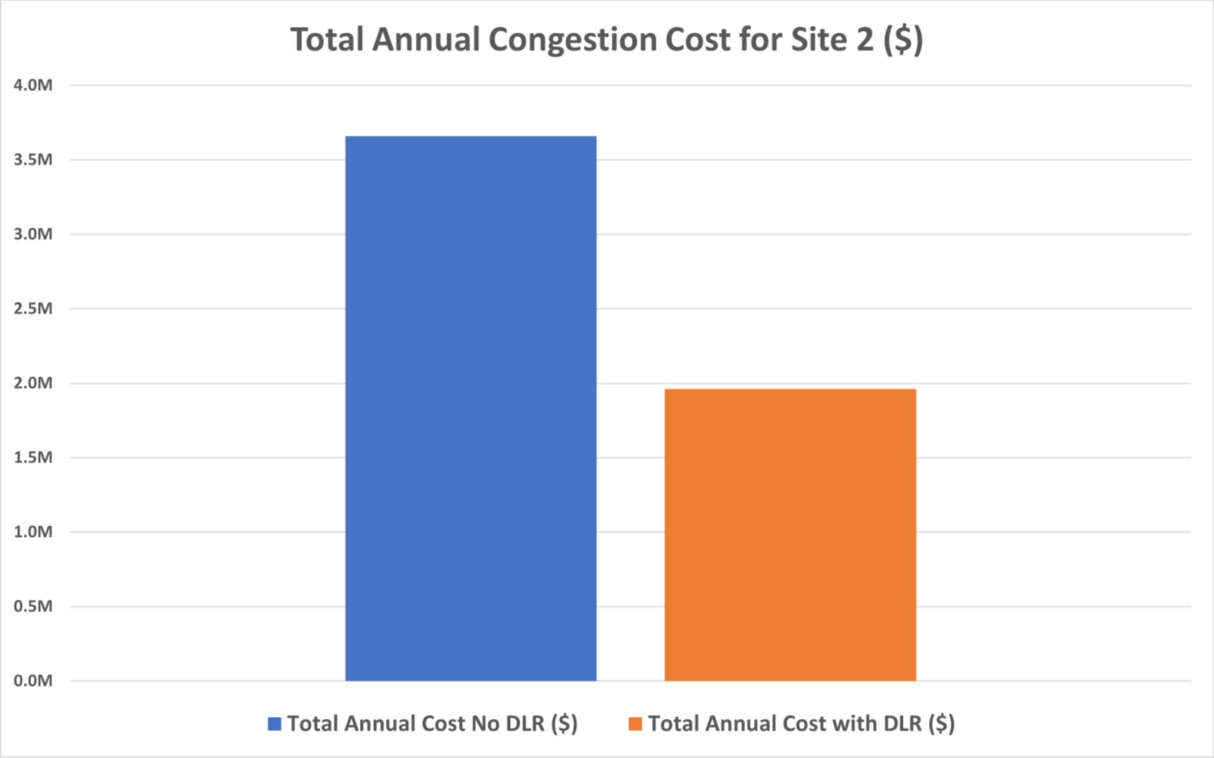
[5] Murphy, S. (2019). PJM Interconnection – Federal Energy Regulatory Commission (FERC) Technical Conference on Dynamic Line Rating Technologies. https://www.ferc.gov/sites/default/files/2020-09/Murphy-PJM.pdf, accessed April 2026.

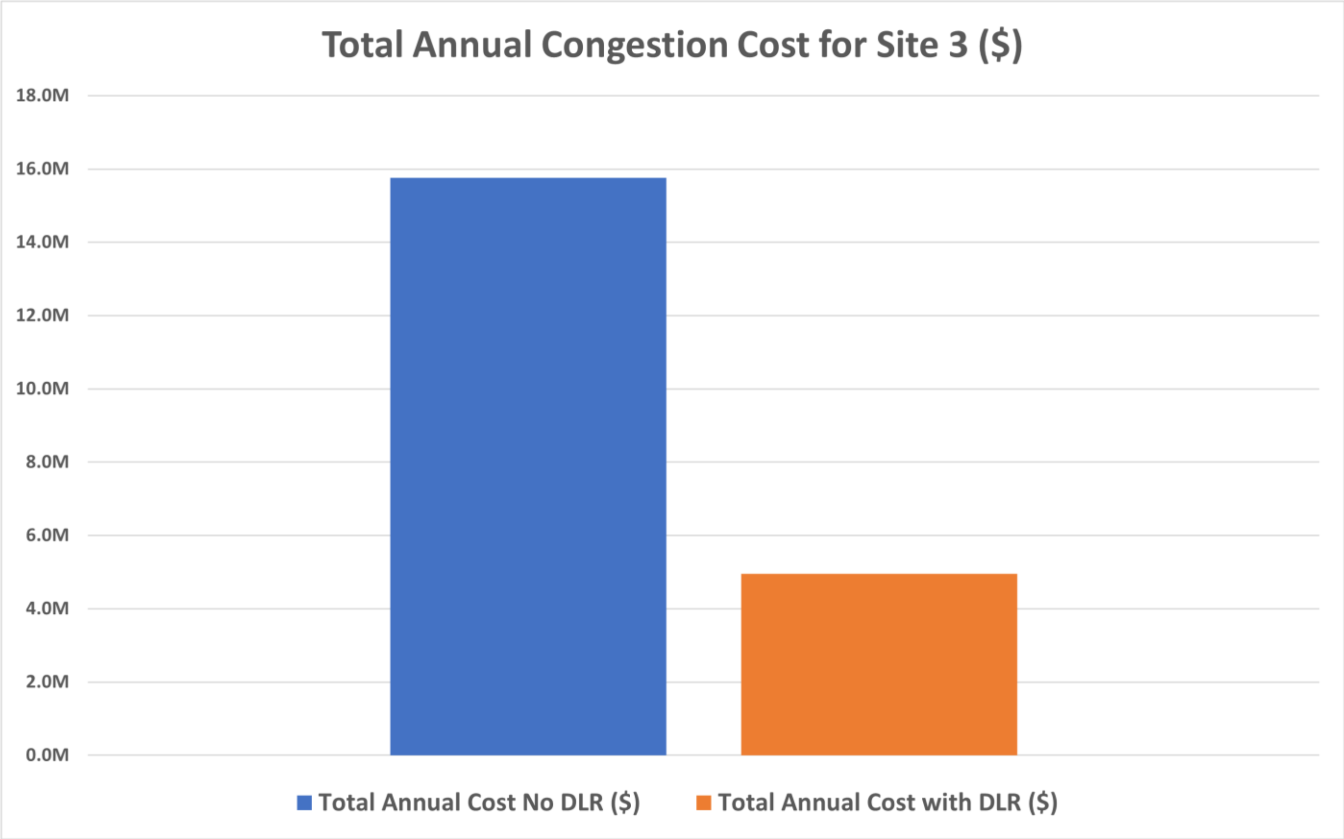
[6] PJM Inside Lines (2018). Report: New Line Technology Boosts Reliability, Reduces Costs. Inside Lines. https://insidelines.pjm.com/pjm-finds-opportunities-in-new-dynamic-line-rating-technologies/, accessed April 2026.

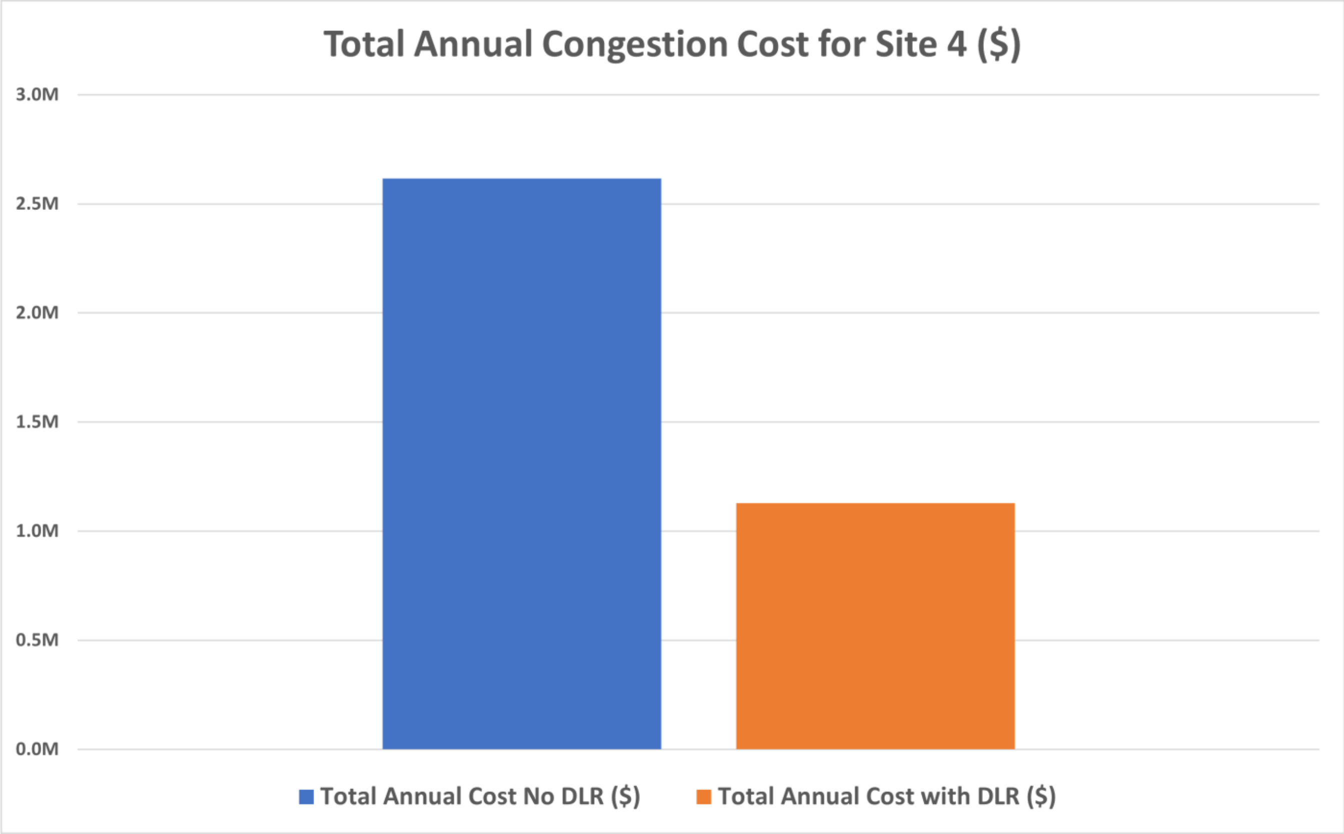
[7] AES & LineVision Dynamic Line Rating Study (April 2024). Lessons from first deployment of Dynamic Line Ratings: 42 LineVision Sensors on 5 diverse AES lines. https://www.aes.com/sites/vault/files/2025-07/AES-LineVision-Case-Study-2024.pdf, accessed May 2026.

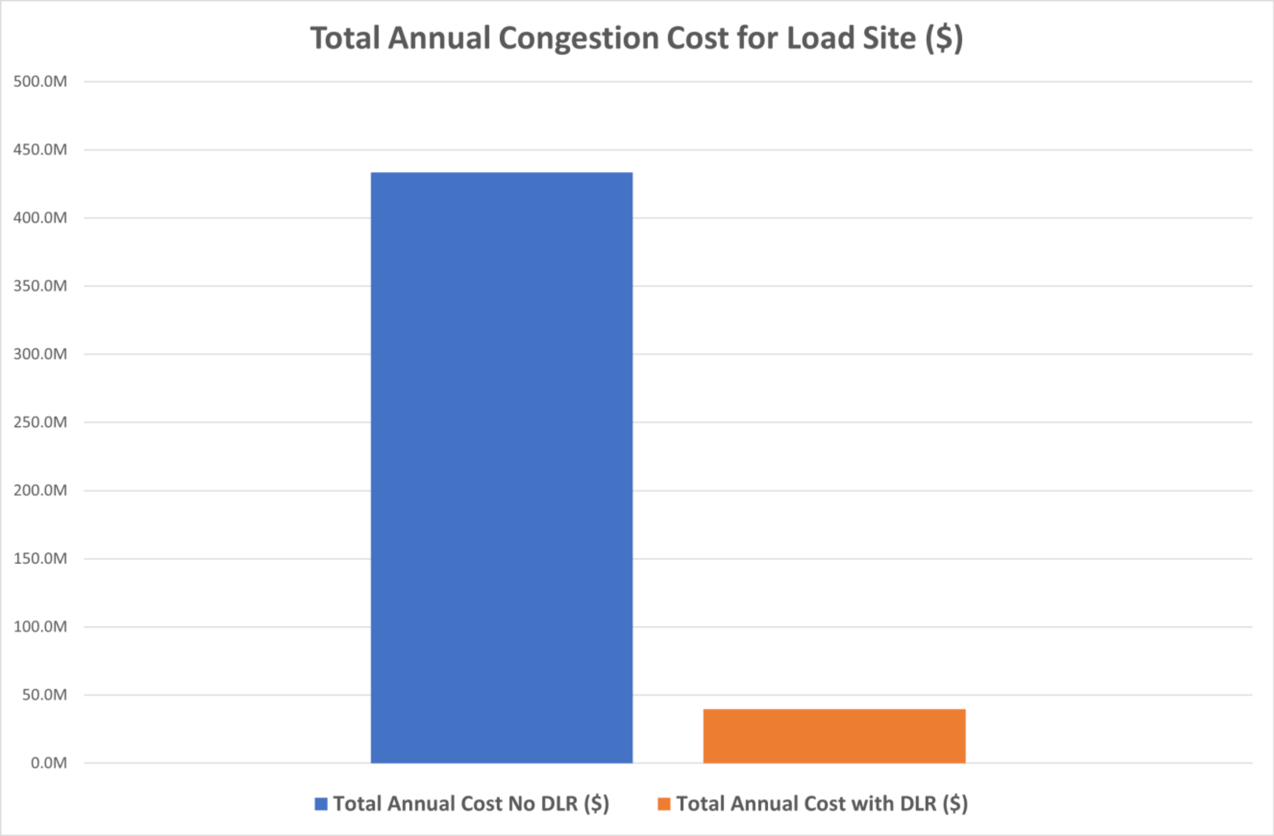
Appendix B. Total Annual Congestion Cost Graphs






Total Annual Congestion Cost for Site 3 ($)
18.0M
16.0M
14.0M
12.0M
10.0M
8.0M
6.0M
4.0M
2.0M
0.0M
Total Annual Cost No DLR ($)
Total Annual Cost with DLR ($)


Total Annual Congestion Cost for Site 4 ($)
3.0M
2.5M
2.0M
1.5M
1.0M
0.5M
0.0M
Total Annual Cost No DLR ($)
Total Annual Cost with DLR ($)


Total Annual Congestion Cost for Load Site ($)
500.0M
450.0M
400.0M
350.0M
300.0M
250.0M
200.0M
150.0M
100.0M
50.0M
0.0M
Total Annual Cost No DLR ($)
Total Annual Cost with DLR ($)

Appendix C. Monthly Total Congestion Cost Tables

Generation Site 1 Monthly Total Congestion Cost ($)			
Month	Cost without DLR	Cost with DLR	Difference
January	$ 299,460.52	$ 188,113.16	$ 111,347.36
February	$ 201,483.96	$ 157,544.91	$ 43,939.06
March	$ 345,694.14	$ 298,420.51	$ 47,273.63
April	$ 422,519.92	$ 333,484.27	$ 89,035.66
May	$ 12,816.06	$ 3,504.75	$ 9,311.31
June	$ 215,709.84	$ 23,675.40	$ 192,034.44
July	$ 578,813.91	$ 79,066.43	$ 499,747.48
August	$ 452,412.57	$ 46,877.12	$ 405,535.46
September	$ 25,879.35	$ 20,750.46	$ 5,128.89
October	$ 207,381.13	$ 149,268.86	$ 58,112.27
November	$ 65,414.14	$ 34,269.27	$ 31,144.87
December	$ 74,100.84	$ 59,636.88	$ 14,463.97

Generation Site 2 Monthly Total Congestion Cost ($)			
Month	Cost without DLR	Cost with DLR	Difference
January	$421,454.19	$ 274,334.76	$ 147,119.43
February	$286,631.23	$ 229,715.82	$ 56,915.41
March	$483,279.48	$ 429,777.87	$ 53,501.61
April	$576,564.25	$ 420,471.97	$ 156,092.28
May	$ 33,555.75	$ 7,722.34	$ 25,833.41
June	$282,431.74	$ 52,888.44	$ 229,543.30
July	$562,103.34	$ 119,322.05	$ 442,781.29
August	$504,088.20	$ 76,411.58	$ 427,676.62
September	$ 64,188.13	$ 41,617.04	$ 22,571.08
October	$271,496.85	$ 189,542.66	$ 81,954.19
November	$ 79,909.01	$ 39,023.85	$ 40,885.16
December	$ 94,194.55	$ 79,923.38	$ 14,271.17

Generation Site 3 Monthly Total Congestion Cost ($)			
Month	Cost without DLR	Cost with DLR	Difference
January	$ 337,753.38	$ 187,573.58	$ 150,179.80
February	$ 423,124.43	$ 159,244.71	$ 263,879.72
March	$ 940,927.18	$ 320,615.21	$ 620,311.97
April	$ 1,687,382.25	$ 482,523.56	$ 1,204,858.69
May	$ 2,073,736.94	$ 768,747.16	$ 1,304,989.78
June	$ 2,944,768.64	$ 1,250,731.67	$ 1,694,036.97
July	$ 3,031,122.65	$ 1,285,419.68	$ 1,745,702.98
August	$ 2,145,340.29	$ 47,672.94	$ 2,097,667.35
September	$ 1,442,070.09	$ 193,690.39	$ 1,248,379.71
October	$ 585,067.37	$ 159,578.90	$ 425,488.47
November	$ 69,816.79	$ 35,251.20	$ 34,565.58
December	$ 81,257.23	$ 61,678.89	$ 19,578.34

Generation Site 4 Monthly Total Congestion Cost ($)			
Month	Cost without DLR	Cost with DLR	Difference
January	$ 240,729.77	$ 142,405.36	$ 98,324.41
February	$ 163,460.98	$ 125,730.35	$ 37,730.63
March	$ 282,066.71	$ 257,711.91	$ 24,354.79
April	$ 353,931.02	$ 261,765.33	$ 92,165.69
May	$ 11,231.09	$ 2,846.01	$ 8,385.08
June	$ 217,253.46	$ 23,643.65	$ 193,609.82
July	$ 565,906.23	$ 59,208.08	$ 506,698.14
August	$ 455,724.29	$ 42,965.27	$ 412,759.02
September	$ 39,379.16	$ 19,769.87	$ 19,609.29
October	$ 171,237.97	$ 117,356.01	$ 53,881.96
November	$ 53,554.61	$ 29,549.23	$ 24,005.38
December	$ 61,704.35	$ 45,444.86	$ 16,259.49

Load Site Monthly Total Congestion Cost ($)			
Month	Cost without DLR	Cost with DLR	Difference
January	$ 50,503,070.00	$ 3,711,877.00	$ 46,791,193.00
February	$ 48,133,694.50	$ 691,138.50	$ 47,442,556.00
March	$ 58,390,171.50	$ 9,818,601.00	$ 48,571,570.50
April	$ 66,499,994.00	$ 15,607,806.50	$ 50,892,187.50
May	$ 4,066,621.50	$ 245,635.00	$ 3,820,986.50
June	$ 6,367,572.50	$ 131,449.50	$ 6,236,123.00
July	$ 11,293,931.50	$ 110,116.50	$ 11,183,815.00
August	$ 10,048,960.00	$ 106,691.00	$ 9,942,269.00
September	$ 2,061,433.50	$ 21,950.50	$ 2,039,483.00
October	$ 66,421,540.00	$ 1,692,288.00	$ 64,729,252.00
November	$ 54,609,233.00	$ 5,293,444.00	$ 49,315,789.00
December	$ 55,023,469.50	$ 2,920,060.00	$ 52,103,409.50