UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Innovations and Efficiencies in Generator Interconnection	**))**	**Docket No. AD24-9-000**

PRE-WORKSHOP COMMENTS AND EXHIBIT OF TYLER H. NORRIS OF DUKE UNIVERSITY

INNOVATIONS PANEL 2: EXPLORING DIFFERENT APPROACHES TO PROCESSING AND STUDYING GENERATOR INTERCONNECTION REQUESTS

Contents

I. Introduction

In April 2024, the U.S. Department of Energy released the agency's first Transmission Interconnection Roadmap, including several solutions related to flexible interconnection service:[1]

- Solution 2.5: Create new and better use existing fast-track options for interconnection, such as surplus interconnection service, generation replacement service, and energy-only interconnection service.
- Solution 3.2: Ensure that generators have the option to elect energy-only interconnection and be re-dispatched rather than paying for network upgrades.
- Solution 3.3: Explore and evaluate options for delinking the interconnection process and network upgrade investments to increase up-front interconnection cost certainty.

Meanwhile, one U.S. electricity market, the Electric Reliability Council of Texas (ERCOT), has recently attracted attention for achieving significantly faster interconnection rates:[2]

- ERCOT interconnected nearly twice as much total capacity than PJM between 2021–2023, despite serving an electricity demand that is only half of PJM's peak load.
- ERCOT has the fastest interconnection processing rate of any market, requiring nearly 2X less time than markets like PJM and NYISO in terms of duration from interconnection request to interconnection agreement.[3]
- For interconnection requests from 2000-2018, ERCOT (30%) had the second-highest project completion rate after ISO-NE.[4]
- Texas interconnected twice as much utility-scale solar as California over the past five years,[5] despite California's aggressive decarbonization goals, and in 2023 Texas surpassed California to become the top U.S. state for installed utility-scale solar.

ERCOT's exceptional interconnection performance has prompted questions about the unique factors that distinguish it from other transmission providers. As an energy-only electricity market, ERCOT operates without a capacity market, meaning that generators do not seek interconnection services that allow them to sell capacity. Instead, all generators connect as "energy-only" resources. The overall trade-off for generators is the ability to interconnect much more quickly with minimal network upgrades, in exchange for bearing more curtailment risk and not receiving separate capacity revenue.

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[1] U.S. Department of Energy. *Transmission Interconnection Roadmap: Transforming Bulk Transmission Interconnection by 2035. April 2024*. https://www.energy.gov/eere/i2x/doe-transmission-interconnection-roadmap-transforming-bulk-transmission-interconnection

[2] Norris, T. H. 2023. *Beyond FERC Order 2023: Considerations on Deep Interconnection Reform*. NI PB 23-04. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University. https://nicholasinstitute.duke.edu/publications/beyond-ferc-order-2023-considerations-deep-interconnection-reform.

[3] Rand, Joseph, Nick Manderlink, Will Gorman, Ryan Wiser, Joachim Seel, Julie M. Kemp, Seongeun Jeong, and Fritz Kahrl. *Queued Up: 2024 Edition, Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023*. 2024.

[4] Ibid., 29.

[5] Data source is EIA-860.

ERCOT stands out as a unique case among U.S. transmission providers due to its energy-only electricity market. However, at least two other ISO/RTOs—CAISO and NYISO—employ methods for studying energy-only interconnection requests that bear similarities to ERCOT's model. While these markets are currently shaped by state-level policies that prioritize capacity resources in the interconnection process, both CAISO and NYISO provide precedents for less restrictive approaches to Energy Resource Interconnection Service (ERIS) requests. This suggests a broader applicability of more flexible interconnection models across various markets.

The handling of Energy Resource Interconnection Service (ERIS) in interconnection studies is shaped by a complex interplay of factors, including contingency categories, load and generation scenarios, redispatch strategies, minimum distribution thresholds, and cost allocation methodologies. Consequently, the spectrum of ERIS study approaches is broad, ranging from highly restrictive to more accommodating models. While ERCOT represents the most flexible end of this spectrum, there is significant room for other transmission providers to adopt less stringent ERIS frameworks without fully transitioning to ERCOT's model. This prospect underscores the opportunity to capture more benefits from ERIS—especially network upgrade cost savings—in balance with potential reliability concerns.

II. Flexible Interconnection: Advantages and Disadvantages

FERC Question #1:

> *Please discuss the advantages and disadvantages of making ERIS, which requires the proposed generating facility to mitigate overloads through network upgrades to allow the generating facility to operate at full output (albeit without the deliverability analysis that NRIS entails), more like the approach used in the region managed by the Electricity Reliability Council of Texas (ERCOT), sometimes referred to as a "connect and manage" approach, which curtails the generating facility in the study model when needed to minimize network upgrades at the cost of risking real-time curtailments and subsequently identifies necessary network upgrades through the transmission planning process.*

Enabling electricity generators to be treated as more flexible resources in generator interconnection studies has significant potential benefits, but it also requires consideration of limitations and necessary advancements in the capabilities of transmission providers. The first part of this response will review potential benefits, categorized into first-order and second-order benefits. The second part of the section discusses two primary challenges. Given the greater availability of data and analysis, more detail is provided for first-order benefits.

First-Order Benefits: Cost and Speed

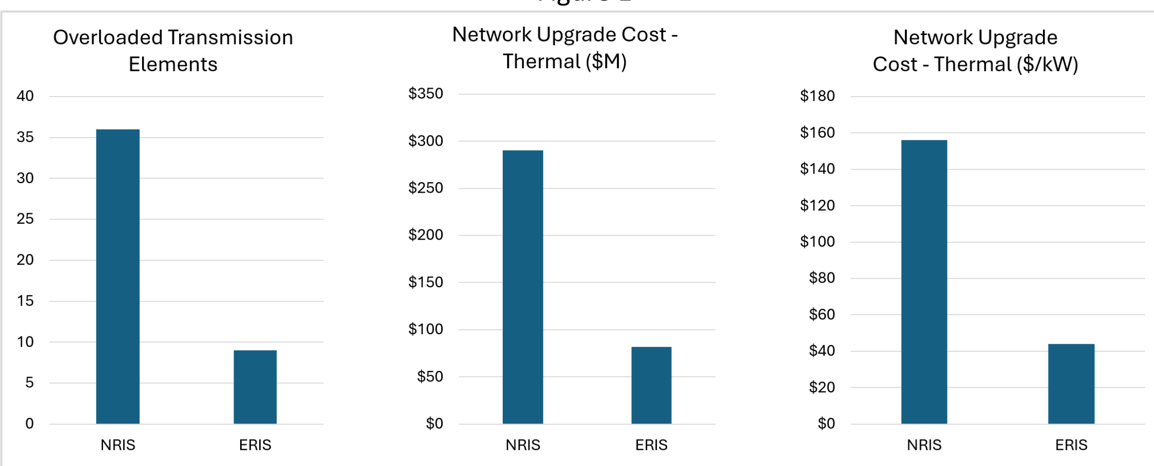
Costs: ERIS Simulation Study

To quantify potential cost savings, an original power flow simulation study was performed for this workshop using modeling software that is widely used by U.S. transmission providers (Exhibit A[6]). Specifically, it analyzed a recent resource solicitation cluster study conducted by Duke Energy Progress (DEP), which required all solar generator interconnection requests (24 projects / 1,858 MWac) to be fully deliverable as Network Resource Interconnection Service (NRIS). The cluster included a mix of state and FERC jurisdictional interconnection requests.

After replicating most of the original study results, we re-simulated the cluster study as ERIS. In summary, our simulation finds that switching from NRIS to ERIS for the selected utility-scale solar cluster results in the following (Figure 1):

- 72% reduction in network upgrade costs related to thermal power flow overloads;
- 75% reduction in identified overloads, including 27 separate transmission elements; and
- Reduction of capacity-weighted costs by $112 per kW of studied solar generation capacity.

Figure 1



These results are notable for several reasons:

- <u>Moderately restrictive scenario:</u> To ensure consistency, we relied strictly on the inputs and assumptions used by DEP, including DEP's latest proposed study criteria for non-firm interconnection requests.[7] This approach to studying non-firm resources still subjects interconnection requests to analysis of single contingencies (TPL-001 P1, P2.1) and requires

[6] Tyler H. Norris and Ryan Watts. "Modeling the Effects of Flexible Interconnection on Solar Integration: A Case Study." Duke University GRACE Lab. Exhibit A to Pre-Workshop Comments of Tyler Norris. FERC Docket No. AD24-9-000. August 26, 2024.
[7] See page 9 of Exhibit A for a detailed description of the study methodology.

them to resolve any associated overloads, making it more restrictive than the approach adopted by transmission provides like CAISO, NYISO, and ERCOT for energy-only requests.

- Conservative cost savings assumptions: To estimate cost savings, we used DEP's cost estimates and only accounted network upgrade costs as saved if the associated overload was fully avoided. This is a relatively conservative assumption since a substantial reduction in a transmission element overloading may require a less expensive upgrade, even if the overload isn't fully mitigated. Estimated cost savings increase if other restrictive assumptions DEP uses are adjusted for ERIS. For example, DEP uses an overload threshold for interconnection studies below the rated current carrying capability of its transmission elements (95%), whereas other transmission providers use a threshold of 100%. If an overload threshold of 100% is used, network upgrade costs fall by 15%. Additional cost savings are possible if emergency ratings are used where applicable, and if modern grid-enhancing technologies are adopted and reflected in interconnection studies to enable higher real-time current carrying limits.
- Optimization for ELCC value: DEP assigns near-zero capacity value (Effective Load Carry Capability, ELCC) to new solar generators, primarily due to the utility's winter-peaking system and DEP's approach to ELCC accreditation. However, DEP requires all projects bidding into its annual solar procurement program to be fully deliverable and subject to NRIS, and it does not provide ERIS as an option to state jurisdictional interconnection requests. In effect, generators that are assigned minimal capacity value are being studied as capacity resources, making those generators more likely to trigger network upgrades than if they were studied as ERIS.

Statistical Analysis of Interconnection Cost Records

The potential cost savings from ERIS and the limitations of predominant ERIS study methods outside ERCOT are further illustrated by cost data from existing interconnection studies. Duke University's GRACE Lab[8] recently analyzed comparative network upgrade costs for NRIS versus ERIS based on the largest public database of U.S. interconnection study costs, released under USDOE's Interconnection Innovation e-Xchange (i2X) by Lawrence Berkeley National Laboratory (LBNL) between 2022-2023.[9] Our analysis included over 3,000 studies with cost data from five RTO regions: ISO-NE, MISO, NYISO, PJM, and SPP.[10] Data from CAISO was unavailable, and ERCOT data is not available since it does not estimate or allocate such costs in interconnection studies.

In summary, we find that on average, ERIS requests are assigned fewer costs than NRIS requests, driven by the higher prevalence of ERIS requests assigned zero cost. However, the anticipated cost advantage

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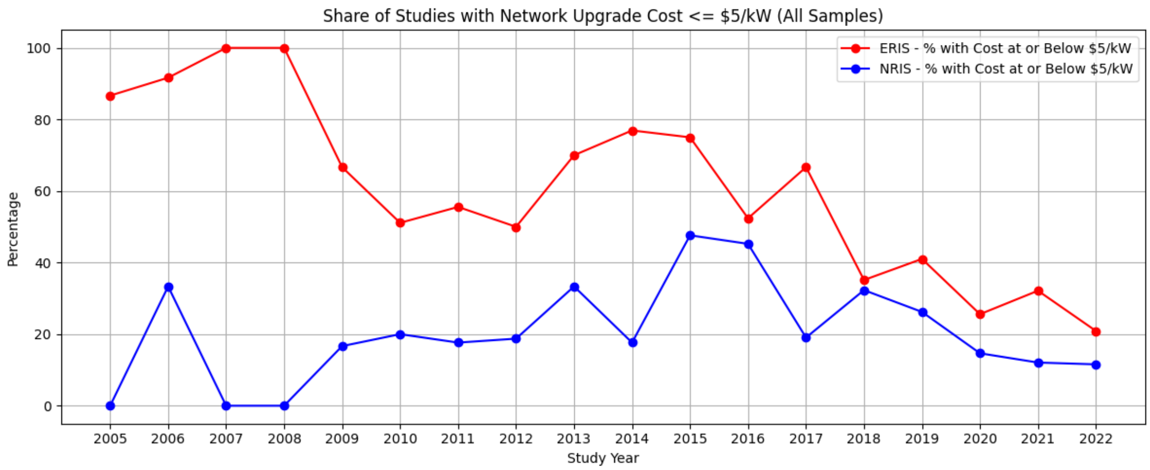
[8] This analysis was performed by Tyler Norris and Dalia Patino-Echeverri. Specific quantitative figures indicated here are considered preliminary and may change between now and when our analysis is published.
[9] Data is sourced from Seel, J., J.M. Kemp, J. Rand, W. Gorman, D. Millstein, F. Kahrl, R.H. Wiser. 2023. Generator Interconnection Costs to the Transmission System - Summary Briefing. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/generator-interconnection-costs.
[10] These data included relevant costs for 3,033 studies, of which 2,150 (i.e., 71%) were for projects applying for NRIS service and 547 (i.e., 19%) for project applying to ERIS service. For 336 studies, the interconnection service type was unclear. 84% of these studies were conducted between 2015 and 2022, with the remainder conducted between 2000 and 2014.

of ERIS over NRIS does not consistently materialize. In MISO, average network upgrade costs assigned to ERIS studies have been consistently higher than NRIS,[11] and the share of ERIS studies with zero or de minimis network upgrade costs ("de minimis" defined here as less than $5/kW) across all available studies has declined significantly over time, and in recent years it is nearly equivalent to NRIS (Figure 2).

Figure 2

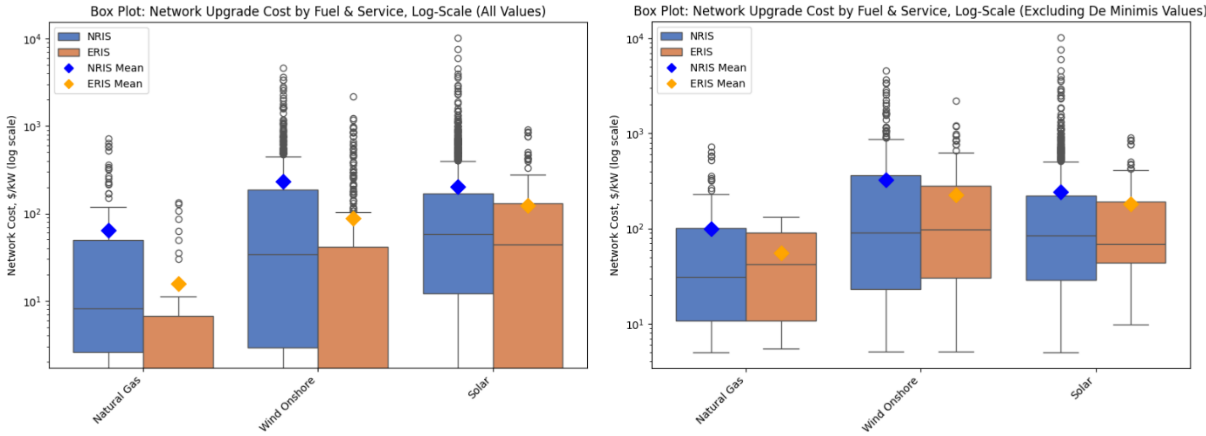


The cost advantage of ERIS diminishes to a statistically insignificant level across all fuel types when only considering cases where network upgrade costs are assigned, excluding cases where zero costs are allocated. This result holds when excluding de minimis network upgrade costs below $5/kW. This conditional analysis, where studies with de minimis costs are excluded, is informative because it reflects the growing prevalence of ERIS studies resulting in allocated network upgrades, and it aligns with our interest in understanding scenarios where upgrades are assigned.

Solar generators exhibit the smallest cost difference between NRIS and ERIS studies. In MISO and SPP, average network upgrade costs for solar ERIS studies are higher than for solar NRIS studies. When considering all available studies, the average network upgrade cost assigned to solar ERIS requests is 60% of the cost for NRIS, with the median being 75%. When excluding studies with de minimis costs, these figures increase to 75% and 82%, respectively, with the difference no longer statistically significant. Wind and gas generators show a similar pattern when samples with negligible costs are excluded. Notably, for wind, the median upgrade cost for ERIS becomes 38% higher than for NRIS under these conditions (Figure 3).

[11] A similar finding was reached by John D. Wilson, Richard Seide, Rob Gramlich and J. Michael Hagerty, *Generator Interconnection Scorecard: Ranking Interconnection Outcomes and Processes of the Seven U.S. Regional Transmission System Operators* (February 2024), Grid Strategies LLC and Brattle Group. Pg. 60.

Figure 3



The available data does not contain information to discern what has driven the increase in ERIS costs. One explanation may be that the diminishing available network capacity in most markets, as more generators have secured NRIS over time, has also made it more expensive to connect ERIS. That said, without more data, it is difficult to rule out other explanations. For example, it may be that changes in ERIS study criteria and minimum distribution factor (DFAX) thresholds have made NRIS and ERIS increasingly similar in some markets.

Explaining Cost Similarity between ERIS and NRIS

Where ERIS and NRIS network upgrade costs are similar, it may be explained by commonalities in study criteria and cost allocation methodology. The specific treatment of ERIS studies is rarely delineated clearly in ISO/RTO business manuals, making the study criteria challenging to characterize precisely. My current understanding is that MISO studies ERIS under most TPL-001 contingency categories and has traditionally required ERIS generators to pay for identified network upgrades if their DFAX is ≥20% under contingency conditions (or ≥5% under system intact), which MISO recently modified to a more restrictive threshold of 10%. PJM studies ERIS under nearly all contingency categories, except single contingencies. SPP appears to similarly apply most contingency categories to ERIS (see Table 1 for a summary of contingency categories).

Table 1: Contingency Types and Categories		
Contingency Type	**TPL-001 Categories**	**Summary**
No Contingency	P0	Normal operating conditions
N-1	P1, P2	Single-element contingency
N-1-1	P3, P6	Generator or transmission outage, followed by System Adjustments, followed by loss of another single element
N-*k*	P4, P5, P7	Multi-element contingency, such as a fault plus stuck breaker or relay failure to operate (P4-P5), or loss of any two adjacent circuits on common structure plus or bipolar D.C. line (P7)

In contrast, CAISO and NYISO take a substantially more flexible approach. CAISO and NYISO assume that real-time congestion management via redispatch can effectively address all thermal power flow constraints for ERIS generators, provided the ISO secures the transmission facility. In the context of deliverability studies, this means ERIS generators are turned off (i.e., assumed to not dispatch). Concerning non-thermal reliability impacts (e.g., short circuit; see Table 2), where they arise for ERIS generators, breaker replacements may be necessary; CAISO has also used remedial action schemes (RAS). Among ISO/RTOs, CAISO and NYISO's ERIS treatment most closely resemble ERCOT. However, limited interconnection cost data is currently available to assess the impact of this study approach in CAISO and NYISO for assigned network upgrade costs.[12]

Table 2: Interconnection System Impact Studies	
Steady State	• Assesses whether a new generator causes thermal or voltage overloads under normal and contingency conditions in a static state • Violations are mitigated primarily through line reconductoring, line rebuilds, transformer replacement, or re-dispatching generation

Stability	• Assesses generator effects on stability (transient, dynamic, and voltage)
	  • *Transient stability*: the ability to maintain synchronism and stabilize immediately following large disturbances (e.g., faults, sudden generator loss, abrupt load changes)
	  • *Dynamic stability*: ability to respond to disturbances with longer duration or which lead to oscillatory behavior, over tens of seconds to minutes
	  • *Voltage stability*: ability to maintain acceptable voltage levels, preventing voltage collapse

Short circuit	• Assesses the impact of fault currents on existing electrical infrastructure • If fault current levels exceed protective device ratings (e.g. circuit breakers), the study will identify upgrades to ensure the devices can safely interrupt faults

How ERIS studies are treated for FERC jurisdictional interconnection requests by non-ISO/RTO transmission providers is less clear. In some cases, it appears transmission providers are studying ERIS and NRIS in an identical fashion. For example, Arizona Public Service and NV Energy state in their Open Access Transmission Tariff that "Interconnection Requests shall be grouped in their respective Queue Cluster Window and by geographical areas, and shall be studied together for NRIS without regard to the nature of the requested Interconnection Service, whether ERIS or NRIS."[13] In contrast, Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC) have previously stated that they only study FERC jurisdictional ERIS requests for single contingencies.[14]

Speed of Interconnection Processing

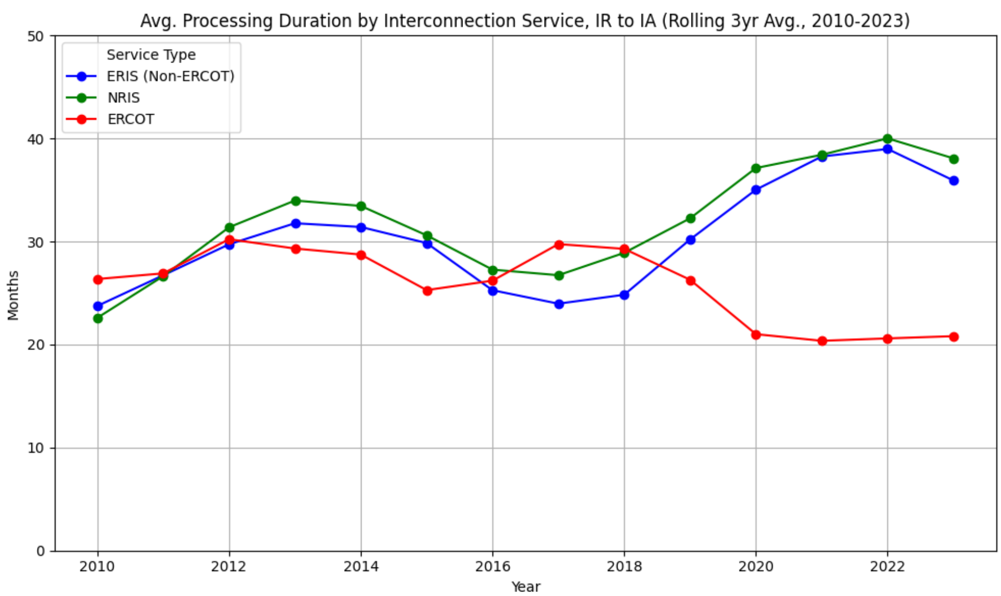
To understand processing timelines, we analyzed the time between the date a project submitted its Interconnection Request (IR) and the date an Interconnection Agreement (IA) was executed, focused on

[12] As previously noted, interconnection cost data is not currently available for CAISO. For NYISO's interconnection cost data set, clarifications are needed regarding whether deliverability costs are reflected or not, and if so, for which studies.
[13] Norris, *Beyond FERC Order 2023*, 6.
[14] Duke Energy Progress, LLC 2022 Definitive Interconnection System Impact Study Phase 1 Report November 23, 2022. Pg. 79. https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022_DEP_DISIS_Phase_1_study_report_11-23.pdf
Duke Energy Carolinas, LLC 2022 Definitive Interconnection System Impact Study Phase 1 Report November 23, 2022. Pg. 71. https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2022-11-23_DEC_2022_DISIS_Phase_1_Study_Report.pdf

IAs executed after 2009. IA execution dates were available for a total of 3,042 projects from six RTO regions: CAISO, ERCOT, ISO-NE, MISO, PJM, SPP, and for a subset of non-ISO/RTO transmission providers in the Southeast and West.[15] The data provided for NYISO contained no interconnection service labels and were excluded from our analysis.

One of the clearest results is that ERCOT demonstrates materially shorter processing durations than non-ERCOT studies. This difference has grown sharply over time, especially since 2018, and is statistically significant (Figure 4). This result was also produced independently by LBNL, which also found that ERCOT's interconnection processing speed is faster than any region overall. Meanwhile, outside ERCOT, NRIS and ERIS projects in aggregate did not demonstrate a statistically significant difference in processing speed (Figure 5). The exception is for gas generators, which experienced shorter durations under ERIS than NRIS. In other words, outside ERCOT, gas appears to have benefited most from ERIS to date in terms of interconnection processing speed.

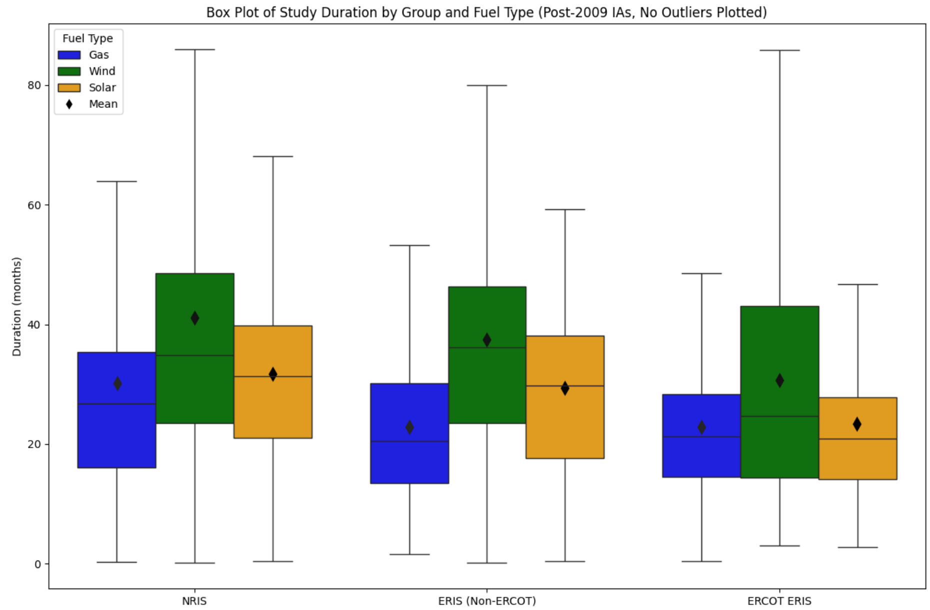
Figure 4



Without additional data, it isn't easy to discern how much of the difference in process speed between ERCOT and non-ERCOT jurisdictions is due to the length of study periods versus the response times of interconnection customers at various stages of the process. However, it is reasonable to assume that the similarity in study methods for ERIS and NRIS outside ERCOT, and the oft-comparable network upgrade costs, is a significant explanatory factor. Such an approach would be expected to require a longer study duration, given the need to reasonably estimate and allocate network upgrade costs, as well as longer interconnection customer response times. Regardless, the results suggest that study treatment similar to ERCOT could have meaningful processing speed benefits.

[15] Data is sourced from Rand, J. et. al. 2024.

Figure 5



Another contributing factor could be the practice of some transmission providers studying ERIS and NRIS requests together in the same batches, with few, if any, opportunities for ERIS projects to exit the process early. While ERIS studies could be completed more quickly, combining them with NRIS studies may extend the processing time for ERIS requests. The requirement under Order 2023 for single-phase cluster studies could lead to a similar outcome unless more defined off-ramps are provided for ERIS projects with minimal system impact.

Second-Order Benefits

The first-order benefits of less restrictive ERIS treatment identified above can generate a number of second-order benefits. Several of these are outlined below, although this list is not intended to be exhaustive, and each of these potential benefits would benefit from further analysis and quantification.

Production cost savings

Enabling more ERIS generation can increase the supply of lower-cost electricity, leading to system-wide production cost savings. Several factors contribute to this outcome. First, expanding the pool of electricity generators fosters a more competitive wholesale market for real-time and day-ahead energy, as more generators vie to meet a fixed energy demand. Second, adding more zero-marginal-cost generators tends to exert downward pressure on wholesale electricity prices by reducing reliance on higher-marginal-cost generation. Finally, ERIS generators that face lower network upgrade costs may be able to offer lower bids in both wholesale energy markets and PPA-based procurement programs, depending on how much the avoided upgrades affect their expected annual curtailment rates. To the extent that lower-cost production from ERIS generators is curtailed due to network congestion, these potential cost savings would factor into the transmission planning process.

Reduced burden on transmission providers and supply chains

More utilization of ERIS could reduce the burden on transmission providers in several ways. First, transmission providers may be able to dedicate fewer resources to studying and processing such requests. Second, by mitigating the extent of network upgrades required per project, transmission providers may be able to focus more of their limited planning and construction resources on the highest-value upgrades. Finally, higher ERIS utilization could relieve already-stressed supply chains by reducing demand for transmission upgrade services and equipment. In the aggregate, reduced demand for such services and equipment could put downward pressure on their prices.

Improved transmission planning

Getting more generators online through ERIS can provide valuable data to inform transmission planning. One of the central challenges for proactive grid planning is accurately predicting where new generators will seek to interconnect. The presence of more interconnected generators (and generators with executed interconnection agreements) helps address this information gap and improve certainty regarding where new generators are located on the grid and their expected production costs. This enhanced coordination between generation and transmission planning could lead to more efficient grid development, helping transmission providers to identify better and prioritize the highest-value upgrades.

Enhanced stability of NRIS clusters

A more viable ERIS option could relieve NRIS/deliverability studies, depending on the interaction between ERIS and NRIS in the context of clusters. If ERIS requests are removed from NRIS studies – such as by studying ERIS requests separately and "turning off" ERIS requests in thermal deliverability studies – the size of NRIS clusters could be reduced, decreasing complexity and allowing finite study resources to focus on a smaller number of generators. This would provide a related benefit of helping insulate NRIS studies from potential queue exits by ERIS requests, reducing interdependency and making NRIS clusters more stable and predictable.[16] However, to realize these benefits, interconnection requests entering the NRIS cluster would not be allowed to switch their status to ERIS during the cluster, which could re-introduce instability.

Option value for firm capacity expansion

By definition, ERIS generators are not counted toward resource adequacy requirements. However, all else being equal, the presence of more ERIS generators can provide option value to expand the supply of firm capacity more quickly. If an ERIS generator is already under construction or operational, it can upgrade to NRIS relatively quickly if network capacity becomes available. By comparison, a proposed, unbuilt NRIS generator attempting to secure the same newly available network capacity could require

[16] Similar justification has been offered by certain transmission providers for utilizing "resource solicitation clusters" separate from general DISIS clusters, e.g. see Duke Energy Progress and Duke Energy Carolinas' annual Solar Procurement Program. https://www.dukeenergyrfpcarolinas.com/

years to secure project finance and complete construction, and its construction timeline would be subject to inherent uncertainties. This option value is similar to the concept of "just-in-case" inventory in supply chain management, which refers to maintaining a stock of resources to meet unexpected demand or adapt to disruptions quickly.

Potential reduction in loss of load risk

While not formally designated as capacity resources, ERIS generators can still play a valuable role in mitigating loss of load risk during stressed grid conditions within any given balancing authority. Contingency scenarios, such as unplanned generator outages or transmission and substation failures, can prevent capacity resources from being fully deliverable to some regions of the network. Although resource adequacy requirements are designed to avoid these scenarios based on the 1-in-10 standard, events like Winter Storm Elliott demonstrate that such risks still materialize under extreme conditions. The extent to which any given ERIS generator contributes to mitigating loss of load risk depends on a range of factors, including its location and the specific grid conditions at the time. However, all else being equal, a larger number of ERIS generators on the system increases the grid's flexibility and option value, enhancing its ability to serve load during extreme contingencies.

Public health and environmental benefits

While FERC may not be statutorily authorized to prioritize public health and environmental benefits with respect to generator interconnection procedures, these benefits are nonetheless significant and should not be overlooked. Fuel-saving resources, particularly those that reduce emissions from fossil-fueled generators, contribute to improved air quality and reduced greenhouse gas emissions. To the extent that a more viable ERIS option removes barriers to market entry for fuel-saving generators while maintaining grid reliability, the resulting spillover benefits should be integrated into a broader cost-benefit analysis. Though FERC's mandate may be limited, stakeholders—including state regulators, policymakers, and the public—should consider these broader impacts when evaluating and shaping interconnection policies.

Disadvantages

Congestion and its implications

Congestion in the transmission network generally means that lower-cost generation resources that would otherwise be dispatched are unable to reach the load due to network constraints. This situation creates inefficiencies, as higher-cost generation may need to be dispatched to meet demand, leading to increased costs for ratepayers. Persistent congestion can also distort market signals, making it difficult for generators to predict revenues accurately and potentially discouraging investment in new generation. This is particularly concerning for incumbent power plant owners, who may find that their plants are dispatched less frequently as lower-cost, newer generation enters the market. More recently installed generators may also be affected if congestion levels exceed their expectations.

Despite its challenges, congestion primarily represents a market signal indicating potential areas where investment in network upgrades can reduce production costs by alleviating bottlenecks. Not all congestion is worthwhile to relieve,[17] and whether or not to invest in infrastructure upgrades should be based on careful cost-benefit analysis. As the penetration of variable renewable electricity resources continues to grow, congestion is generally expected to increase. VREs, such as wind and solar, are often located in remote areas far from load centers, which can increase the likelihood of violation of network constraints. While this congestion can initially seem problematic, it also represents a clear signal to system operators about where grid investments are most needed.

However, the ability to capitalize on the signals presented by congestion depends on the effectiveness of a jurisdiction's transmission planning process. Jurisdictions with effective planning processes are better positioned to manage the challenges and opportunities presented by an increase in ERIS generators, ensuring that network upgrades are made promptly to support both reliability and economic efficiency. Order 1920, with its emphasis on proactive transmission planning, makes a "connect and manage" approach more viable by ensuring that necessary upgrades are planned and executed to relieve the most significant bottlenecks.

Conversely, introducing more ERIS generation in jurisdictions with weak transmission planning could lead to more significant complications. If too few generators pursue NRIS, insufficient transmission investment may lead to long-term undercapacity and persistent bottlenecks. While the current number of ERIS generators is relatively low in most markets, a significant shift towards ERIS could strain the network if not accompanied by adequate planning and investment. On the other hand, reducing the number of projects pursuing NRIS could streamline the NRIS study process, potentially making it more efficient and allowing for more targeted transmission investments.

Real-time contingency management

If ERIS becomes more accessible and prevalent, with more energy-only generators in operation, the need for real-time management of reliability impacts will increase. While including additional generation resources can enhance grid flexibility and reliability, it also introduces new complexities in grid operation. Integrating a greater number of energy-only generators requires grid operators to be more vigilant in managing congestion and unforeseen conditions that may arise during real-time operations. This increased complexity in grid management could be seen as a downside, necessitating changes in operating protocols and investments in additional tools and capabilities.

In the context of thermal congestion, real-time management can be relatively straightforward, relying on well-established procedures to balance supply and demand and prevent overloads on transmission

[17] SPP commissioned a study to assess if its 20% ERIS DFAX threshold should be altered. The study found that the additional network upgrades triggered by a lower DFAX threshold carried a low cost-to-benefit ratio, at both a system level and generator level. See: Burns & McDonnell Engineering Co, Inc. “HITT T1: ERIS Threshold Study Update.” SPP Transmission Working Group. September 2023.

facilities. However, managing non-thermal reliability risks—such as stability and voltage control—can be more challenging. These issues often require more sophisticated, sometimes nontraditional, solutions. For example, in CAISO, Remedial Action Schemes (RAS) are used to reconfigure the grid or curtail generation to maintain stability automatically. Similarly, ERCOT employs Generic Transmission Constraints (GTC) to manage flow limits across key transmission corridors. While effective, these tools add complexity to grid operations, necessitating additional training, resources, and investment in technology to ensure they function as intended.

The need for these more sophisticated tools could increase the operational burden on grid operators, potentially introducing reliability risk if the tools fail or prove insufficiently robust. On the other hand, more sophisticated, automated systems could relieve the burden on operators. The reliance on real-time management tools for addressing non-thermal reliability issues underscores this risk. The grid could face reliability issues if these tools do not operate as designed during critical moments. Ultimately, while making ERIS more accessible offers potential benefits, it also demands a more robust and resilient approach to grid management, with the associated costs and risks that come with it.

III. Integrating Elements of Connect and Manage

FERC Question #2:

> *How could elements of the ERCOT "connect and manage" approach be incorporated into the current structure of Commission-jurisdictional markets and pro forma generator interconnection procedures and agreements?*

FERC and US transmission providers have significant opportunities to optimize and clarify the treatment of generators seeking flexible interconnection service in order to make more efficient use of the existing grid and expand electricity supply. Several recommendations and areas for further exploration are outlined below. This list is not intended to be exhaustive but rather a starting point to inform considerations and next steps among regulators and system operators. As an immediate next step, FERC could convene a technical conference focused on flexible interconnection service to document existing practices and evaluate priority solutions to inform subsequent rulemaking.[18]

Adopt less restrictive ERIS treatment

A clear opportunity to adapt ERCOT's approach to existing Commission-jurisdictional markets is for transmission providers to adopt ERIS treatment that is more consistent with the intended purpose of the interconnection service. As discussed above, several existing non-ERCOT transmission providers take

[18] This recommendation is echoed by Grid Strategies and The Brattle Group, *Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid* (August 2024), available at https://blog.advancedenergyunited.org/reports/unlocking-americas-energy, and also submitted in pre-workshop materials filed by Advanced Energy United in this docket on August 26, 2024. Pg. 55.

a significantly less restrictive approach, assuming that real-time congestion management via redispatch can address all or most thermal power flow constraints for transmission-interconnected ERIS generators. This direction is consistent with FERC's expressed preference to "create consistency in the modeling standards used across all transmission regions" in Order 2023.[19] However, the existing FERC pro forma procedures and agreement generally reinforce the assumption that ERIS generators are liable to require network upgrades related to steady-state studies, without which maximum output limitations will apply.[20]

Provide an off-ramp for ERIS generators from broader cluster studies

Most of the temporal advantages may be unavailable without an off-ramp for ERIS requests from cluster studies. Different approaches are possible, such as a "minimum interconnection standard" study similar to the pre-existing approach taken by NYISO and ISO-NE for both ERIS and NRIS requests; an independent ERIS-only study option similar to the pre-existing approach offered by CAISO; a fast-track study for ERIS requests that pass an initial screen for non-thermal reliability risk, prior to the NRIS cluster; or another option for ERIS requests to proceed into facilities study following the non-thermal reliability portion of their system impact study.

Consider an entry fee concept for ERIS requests

To date, the “entry fee” concept for generator interconnection requests has been primarily discussed in the context of NRIS requests,[21] but it could also apply to ERIS requests. An entry fee for ERIS requests would contribute to covering the cost of real-time congestion management tools, breaker upgrades, and potential implementation of remedial action schemes (RAS) and other automated solutions to mitigate non-thermal reliability risk. Zonal-level fee assessments could also be considered based on areas of the network with higher short circuit risk and lower short circuit ratios. If such an entry fee were adopted, it could potentially obviate the use of ERIS interconnection studies as a cost discovery tool.

Clarify the relationship between interconnection and transmission service

The intended relationship between interconnection and transmission service in the absence of physical transmission rights has become increasingly unclear, as have the procedures and study methods for the designation of certain transmission services. Some transmission providers allow ERIS generators to achieve capacity designation via firm transmission service, even among ISO/RTOs. MISO[22] reportedly has

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[19] FERC. 2023. Order No. 2023. Docket No. RM22-14-000. Washington, DC: Federal Energy Regulatory Commission. https://www.ferc.gov/media/e-1-order-2023-rm22-14-000. Paragraph 1281.

[20] FERC’s pro forma LGIP states that “steady state studies would identify necessary upgrades to allow full output of the proposed Large Generating Facility” (Section 3.2.1.2), and the pro forma LGIA states that “Interconnection Customer will be eligible to inject power… on an “as available” basis up to the amount of MWs identified in the applicable stability and steady state studies to the extent the upgrades initially required… have been constructed” (Section 4.1.1.2).

[21] See David Gahl, Melissa Alfano, Tiana Elame, "Game Changing Interconnection Reform: Reshaping Transmission Planning and Realigning Incentives,” April 2024. https://www.ssii.org/wp-content/uploads/2024/04/SI2-Interconnection-Whitepaper-04.25.24.pdf

[22] See e.g., MISO. “Generator Interconnection Study Process (ERIS/NRIS) and Cost Allocation.” Regional Expansion Criteria and Benefits Working Group (RECBWG). August 2022. Pg. 3.

up to 10-20 gigawatts[23] of operating generation capacity under this arrangement, and a similar option has been available in SPP.[24] Georgia Power recently submitted ERIS interconnection requests for proposed combustion turbine units at Plant Yates (IC-1166, IC-1167, and 1168),[25] stating in its discovery response that "firm transmission service will be separately obtained through the designation of the resource" and that "requested energy resource interconnection service ('ERIS') does not contribute to or increase the likelihood of transmission constraints or curtailments."[26]

Confirm curtailment procedures for FERC jurisdictional ERIS generators

Treatment of different transmission and interconnection service levels for FERC jurisdictional generators in non-ISO/RTOs concerning real-time operations and curtailment priority is not readily discernable in some jurisdictions. Legacy procedures may have outlived their utility and deserve reevaluation. A potential example to model is the redispatch and curtailment procedures manual of Bonneville Power Administration.[27] One possible case study where clarification may be valuable is the example of FERC jurisdictional generators submitting into the annual resource solicitation clusters of Duke Energy Progress (DEP) or Duke Energy Carolinas (DEC), should DEP/DEC eventually allow those generators to select ERIS.[28]

Modify provisional service to align more with ERIS treatment

Another benefit of ERCOT's interconnection approach is that it allows generators to dispatch energy up to their nameplate capacity before achieving full approval for commercial operation while still operating as a "synchronized" generator, after passing a curtailment test.[29] ERCOT provides this option despite already having significantly faster interconnection processing timelines than other transmission providers, even before considering mounting interconnection delays among FERC jurisdictional transmission providers following the execution of interconnection agreements. In contrast, provisional interconnection service as defined by FERC Order 845 allows an uncertain maximum permissible output limit subject to re-study quarterly or annually. Transmission providers often provide minimal information for interconnection customers to make informed decisions regarding whether to pursue provisional

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https://cdn.misoenergy.org/20220830%20RECBWG%20Item%2003%20Generator%20Interconnection%20Study%20Process%20and%20Cost%20Allocation626135.pdf

[23] It is unclear how to confirm this figure based on available data.

[24] See e.g., SPP. "Energy-Only Resource Planning Update." Strategic Planning Committee Meeting. January 2017. Pg. 8. https://www.spp.org/documents/56312/spc%20additional%20material%2020180118.pdf

[25] See discussion in the direct testimonies of Arne Olson and Michael Goggins in Docket No. 55378, Georgia Power Company's 2023 IRP Plan Update:
Olson testimony: https://psc.ga.gov/search/facts-document/?documentId=217530
Goggins testimony: https://psc.ga.gov/search/facts-document/?documentId=217578

[26] Georgia Power Company. DIT 55378 STF-GS-2 Data Request Responses. February 2024. https://psc.ga.gov/search/facts-document/?documentId=217378.

[27] Bonneville Power Administration. Redispatch and Curtailment Procedures BPA Transmission Business Practice. July 2024. https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/redispatch-and-curtailment-procedures-bp.pdf

[28] See more information regarding this resource solicitation cluster in Exhibit A.

[29] Generators must now pass a curtailment test to connect more than 20 MVA of capacity to at the POI during commissioning.

interconnection service,[30] and it is unclear why the terms of provisional service would differ materially from ERIS. Improvements in provisional service can be valuable to ERIS and NRIS generators alike.

Evaluate the sufficiency of existing congestion management resources

As congestion risk grows, interconnection customers may benefit from additional tools and information to assess and manage their curtailment risk. One potential concept is a "financial interconnection right."[31] Another is FERC's pro forma OATT requirement for conditional firm transmission service that requires the transmission provider to define "a specified number of hours per year" or "System Condition(s)" during which reliability-related curtailment may occur.

Explore deeper reforms to delink interconnection service from network upgrade investments

Consistent with Solution 3.3 of USDOE's Transmission Interconnection Roadmap,[32] FERC should explore longer-term options to delink the generator interconnection process from network upgrades, especially from extensive infrastructure investments related to regional or area upgrades (i.e. "deep" upgrades). Entry fees are one concept gaining support among stakeholders and under consideration by at least one transmission provider.[33] Other options warrant further research, such as periodically reassigning deliverability rights to better align with the physical realities of our evolving grid, ensuring that network capacity is efficiently allocated as network topologies change.[34]

Provide information to clarify interconnection and transmission service treatment

Beyond its rulemaking authority, FERC can play a constructive role by addressing areas of ongoing regulatory uncertainty and misperception that may hinder market participation, even if limited to informational resources such as general guidance documents, webinars, and similar documentation. For example, some market participants remain unclear about how different interconnection and transmission services are treated in real-time operations, which can be a barrier to market uptake for different services.[35]

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[30] See e.g., *Motion to Intervene and Limited Protest of Carolinas Clean Energy Business Association*, FERC Docket No. ER24-2431-000, June 2024. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240719-5250&optimized=false

[31] Mays, J. 2023. "Generator Interconnection, Network Expansion, and Energy Transition." IEEE Transactions on Energy Markets, Policy and Regulation. doi:10.1109/TEMPR.2023.3274227.

[32] USDOE, *Transmission Interconnection Roadmap*, 55-56.

[33] Grid Strategies and The Brattle Group, *Unlocking America's Energy*, Reform #1.

[34] Re-estimation and re-assignment of deliverability value is already occurring to some degree via increasingly granular capacity accreditation methods. Combined with ongoing vulnerability of "firm" resources to network congestion, these trends may raise questions regarding the value of using interconnection service to assign permanent capacity designation.

[35] See for example: Rao Konidena, *Connect and manage - is that the future for new generator interconnections?*, Feb. 2024: "A firm Interconnection Service like NRIS means your generator output will not be curtailed unless there is an emergency event. A non-firm Interconnection Service like ERIS means your generator output could be curtailed first to accommodate firm transactions. That is the key difference between NRIS and ERIS."

FERC Question #2a-b:

a. Could customers interconnecting under this type of approach eventually increase their deliverability or reduce curtailments, such as by later converting to NRIS? How would this conversion be accomplished?

b. In the context of RTO/ISO markets, how would an RTO/ISO account for resources' differing levels of interconnection service (e.g., "connect and manage" versus NRIS or its equivalent) and any associated capacity rights when dispatching resources pursuant to security-constrained economic dispatch?

Upgrading from ERIS to NRIS

An interconnection customer should be able to upgrade from ERIS to NRIS, or to any other deliverable service tier which may be available. ERIS vs. NRIS designation generally has less to do with characteristics specific to the generator or its interconnection facilities and more to do with network infrastructure. An ERIS generator could sometimes upgrade to NRIS without any network modifications, if network capacity becomes available.

Under most interconnection procedures, an existing ERIS generator would simply submit a new interconnection request for NRIS in the next queue cycle to pursue such an upgrade. Such an NRIS request could be limited to a portion of the generator's nameplate capacity, for example, if the generator added a paired battery storage device and did not want to pay for NRIS beyond the battery's nameplate capacity. In some markets, such as MISO and SPP, ERIS generators have been eligible to secure capacity designation via separate firm transmission service. In this scenario, an ERIS generator under non-firm transmission service would submit a request for firm transmission service per the procedures associated with transmission service requests.[36]

To the extent that ISO/RTOs maintain capacity markets, the ability to upgrade ERIS to capacity provides option value to more quickly expand the supply of firm capacity as needed, to the benefit of system operators and interconnection customers alike (see prior discussion related to second order benefits). Restricting or eliminating this upgrade option would likely diminish the appeal of ERIS, further reducing its already limited use.

Interconnection service in real-time operations

The treatment of interconnection service in real-time operations, including security-constrained economic dispatch, has been uncertain to some market participants. However, upon closer inspection, it is apparent that RTO/ISO operators do not distinguish between generator interconnection service types in real-time operations.[37] This would be expected based on the principles of competitive economic

[36] As noted previously, the procedures and study methods governing ERIS designation as capacity under separate transmission service would benefit from clarification.
[37] See e.g.,

dispatch and real-time contingency management. Capacity resources have no right to preferential dispatch in real-time and day-ahead energy markets, irrespective of system conditions. In other words, ERIS and NRIS are treated on a level playing field for curtailment priority with respect to both congestion-related curtailment and system emergency response.

IV. Other Improvements

FERC Question #3:

What other approaches could build on the pro forma generator interconnection procedures and agreements adopted in Order No. 2023 to more efficiently organize interconnection queues and process interconnection requests?

a. *Should transmission providers proactively identify zones where there is currently available transmission capacity or new transmission capacity due to planned transmission facilities and provide information on these zones to interconnection customers? If so, how should transmission providers identify these zones and how should they communicate that information to interconnection customers?*
b. *If transmission providers identify zones, as described in (a) above, should auctions be used to assign queue positions or allocate excess transmission capacity in those zones? What other approaches could be considered?*
c. *How could such procedures ensure that generator interconnection service is consistent with open access principles and is provided in a manner that is not unduly discriminatory or preferential?*

A first-order requirement for developing a new power plant is securing site control over a viable land position, informed by a reasonable expectation that necessary permits required for project construction can ultimately being obtained. However, even after securing a site, multiple permitting stages—along with other development-related risks—can introduce significant uncertainty, often persisting deep into the development process. This uncertainty is intensifying across many jurisdictions as land use restrictions become more stringent.

MISO: "A generator's type of interconnection service is not considered in the DA & RT markets; generation with ERIS and NRIS are treated the same in unit commitment and economic dispatch." Pg. 3.
https://cdn.misoenergy.org/20220830%20RECBWG%20Item%2003%20Generator%20Interconnection%20Study%20Process%20and%20Cost%20Allocation626135.pdf
SPP: "LSEs or Merchants with Energy Resources compete equally in the market with those that have Capacity Resources... Little difference in the treatment of ERIS and NRIS after the GI study process." Pg. 7.
https://www.spp.org/documents/56312/spc%20additional%20material%2020180118.pdf

Siting uncertainty poses one of the greatest challenges to proactive transmission planning, especially in regions that face more uncertainty regarding viable project locations. Transmission planners face the difficult task of anticipating where new generators will locate, particularly when developers have not yet secured sites or submitted interconnection requests. If network capacity exists in certain zones that could accommodate new power plants, why haven't developers capitalized on these opportunities by submitting interconnection requests?

With respect to planning greenfield transmission projects, there is typically less uncertainty around anticipating generator siting potential. This is because greenfield development is likely designed with the specific purpose of reaching zones with high certainty of accommodating more generators, and because the geographic areas suitable for new transmission rights-of-way often coincide with areas where new power plants can be sited. By definition, such areas tend to be less saturated with existing development-stage generators, given the pre-existing absence of transmission.

In contrast, when it comes to planning upgrades to existing transmission, the challenge of anticipating generator siting decision may be greater, particularly in the absence of existing interconnection requests—or ERIS generators with executed interconnection agreements—to inform planners.

If asymmetric information on existing or prospective transmission headroom is a material factor explaining the lack of existing interconnection requests in a particular area, then the identification of such zones by transmission providers may indeed be valuable. For example, one area of generally non-transparent network information that could help with proactively guiding generators—especially ERIS generators less concerned about full deliverability—is a list of buses pre-screened for non-thermal reliability risk (i.e., stability and short circuit risk). Although information on thermal network capacity is increasingly accessible, non-thermal network capacity is not.

However, if such asymmetric information is not a material factor, such an approach may not be effective. A thorough consideration of proactive transmission planning and assignment of new network headroom is beyond the scope of this document. However, it is worth underscoring again that improved viability of ERIS could lead to less uncertainty and more valuable data to inform proactive transmission planning, as discussed previously (see "Second-Order Benefits").

Exhibit A: ERIS Simulation Study

See next page

Modeling the Effects of Flexible Interconnection on Solar Integration: A Case Study

Prepared for: FERC Innovations and Efficiencies in Generator Interconnection Staff-Led Workshop

August 26, 2024

Tyler H. Norris

Ryan Watts, P.E.

Duke University

Acknowledgements and Disclaimer

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About the Authors

Tyler H. Norris is a J.B. Duke Fellow and PhD student at Duke University's Nicholas School of the Environment in the GRACE Lab. His current research focuses on grid interconnection and its relationship to electric power markets, with an emphasis on market and regulatory analysis and techno-economic modeling, building on professional roles in utility-scale power project development, electricity market analysis, and USDOE technology-to-market programs.

Ryan Watts is a transmission planning engineer and licensed professional electrical engineer in the state of Nevada. Watts previously managed Transmission Planning at NV Energy, a public utility serving 2.4 million electric customers across Nevada, where his responsibilities included overseeing and conducting FERC interconnection and transmission service studies, supporting NERC compliance, and ensuring compliance with FERC policy. He is currently the Director of Grid Integration Engineering at Cypress Creek Renewables.

Table of Contents

Executive Summary

Takeaway

Treating solar as a more flexible, curtailable resource in generator interconnection studies has the potential to avoid significant costs related to network upgrades and accelerate generator additions, while maintaining reliability.

Study Results

Power flow modeling produced the following results when solar generators were treated as energy-only resources instead of capacity resources, in the context of a recent interconnection cluster study:

- Avoided 75% of identified overloads, representing 27 separate transmission elements;
- Saved 72% of network upgrade costs related to thermal power flow overloads; and
- Reduced capacity-weighted costs by $112 per kW of studied solar generation capacity.

Additional Opportunities

The analysis suggests that improving energy-only interconnection service among some US transmission providers could provide material benefits. Additional cost savings may also be possible with the following steps:

- Transmission elements are rated at the maximum weather adjusted capability of the equipment, and at emergency ratings where applicable;
- Modern grid enhancing technologies are adopted and reflected in interconnection studies to enable higher real-time current carrying capability limits; and
- Energy-only interconnection studies adopt treatment similar to system operators like NYISO, CAISO, or ERCOT.

Background: Research Motivation

Potential Solutions

In April 2024, the U.S. Department of Energy released the agency's first Transmission Interconnection Roadmap. The roadmap contained several solutions related to flexible interconnection service, including:

- Solution 2.5: Create new and better use existing fast-track options for interconnection, such as surplus interconnection service, generation replacement service, and energy-only interconnection service.
- Solution 3.2: Ensure that generators have the option to elect energy-only interconnection and be re-dispatched rather than paying for network upgrades.
- Solution 3.3: Explore and evaluate potential options for delinking the interconnection process and network upgrade investments to increase up-front interconnection cost certainty.

Research Gap

There is limited existing research on the potential benefits and reliability implications of flexible interconnection options. To address this gap, we conducted a power flow simulation comparing the results of inflexible and flexible interconnection service for solar generators.

U.S. DEPARTMENT OF ENERGY

Transmission Interconnection Roadmap

Transforming Bulk Transmission Interconnection by 2035

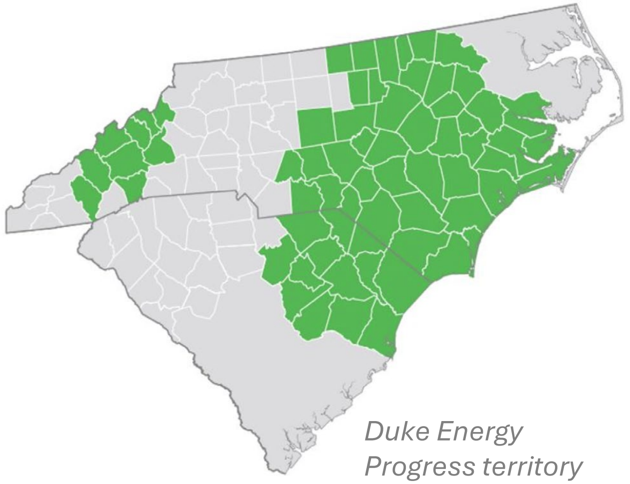
April 2024

https://www.energy.gov/articles/doe-releases-first-ever-roadmap-accelerate-connecting-more-clean-energy-projects-nations

Background: Duke Cluster Study

Selection of Real-World Interconnection Study for Re-simulation

- To assess potential benefits of flexible interconnection service, we considered recent cluster studies that could be replicated and re-simulated using alternative assumptions.
- We selected Duke Energy Progress' (DEP) 2023 Resource Solicitation Cluster (RSC) Phase 1 study released in April 2024, conducted for DEP's annual solar procurement.
- The DEP RSC study offered a uniquely instructive case study, because it isolates the interaction of utility-scale solar projects with prevailing interconnection study methods.



Duke Energy Progress territory

Summary of Key Inputs and Assumptions for Duke Study

- Resources: 24 separate solar/solar-plus-storage generator interconnection requests (1,858 MW)
- Study type: Thermal power flow. The Phase 1 study did not include stability or short circuit analysis.
- Load cases: 2027 summer and 2027/28 winter.
- Interconnection service: 100% Network Resource Interconnection Service (see more pg. 8)
- Capacity value: DEP assigns near-zero capacity value (Effective Load Carrying Capability, ELCC) to solar.
- Curtailment: DEP does not consider the ability to redispatch/curtail solar in summer peak hours to mitigate transmission overloads.

Background: Duke Cluster Study

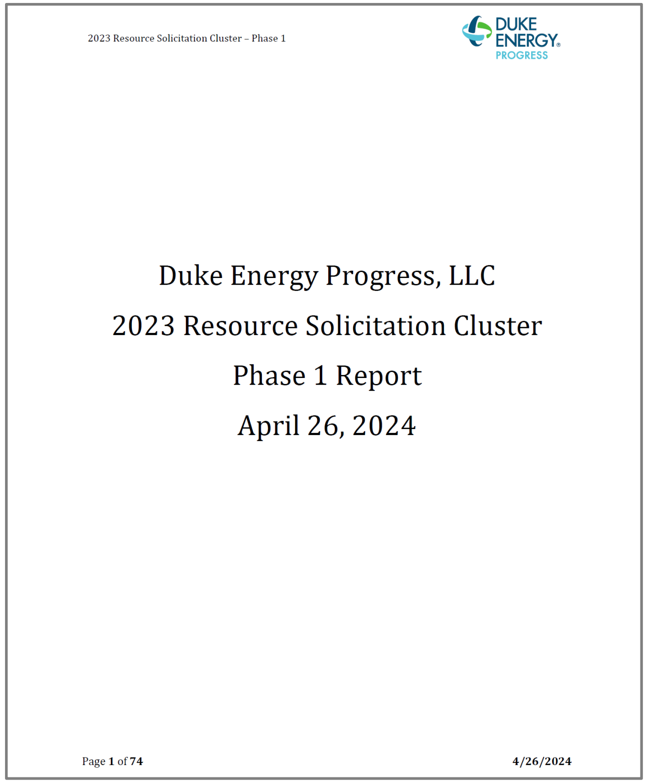
Results of Duke Cluster Study

<u>Network Update Costs</u>

- The DEP RSC Phase 1 study identified $470 million in network upgrades, or approximately $250 per kW of solar nameplate capacity.
- $350 million of these were thermal power flow related upgrades, with the remainder attributed to POI and telecommunication upgrades.
- The average network upgrade cost per project was $20 million. Nearly 70% of projects were allocated at least $10 million, and 33% were allocated at least $20 million.

<u>Upgrade Timeline</u>

- The average time estimated for completion of such upgrades by DEP was 4.5 years following the execution of an interconnection agreement, ranging up to 7 years.


2023 Resource Solicitation Cluster – Phase 1

Duke Energy Progress, LLC
2023 Resource Solicitation Cluster
Phase 1 Report
April 26, 2024

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Source: Duke Energy Progress, LLC. 2023 Resource Solicitation Cluster Phase 1 Report. April 26, 2024. https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2023_DEP_Resource_Solicitation_Cluster_(Phase_1)_Study_Report.pdf

Background: NRIS vs. ERIS

Definitions

Per FERC guidance, transmission providers are required to offer at least two interconnection services to FERC jurisdictional interconnection customers: Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS).[1] Whereas NRIS is required to be designated as a capacity resource, ERIS is ineligible for capacity designation.[2] NRIS subjects interconnection requests to more rigorous reliability analysis and thus generally entails higher network upgrade costs.

Solar NRIS vs. ERIS in Duke Energy Progress

DEP assigns near-zero capacity value (ELCC) to new solar generators, primarily due to the utility's winter-peaking system and its approach to ELCC accreditation. However, DEP requires all projects bidding into its annual solar procurement program to be fully deliverable and subject to NRIS, and it does not provide ERIS as an option to state jurisdictional interconnection requests.[1] In effect, generators without deliverability value are being studied for deliverability, making those generators more likely to trigger network upgrades than if they were studied as ERIS. This study aims to illuminate the impact of this requirement for interconnection studies and network upgrade costs.

NRIS vs. ERIS study assumptions

NRIS requests are generally subject to all contingency types defined in NERC Reliability Standard TPL-001 (P1-P7) and various stress cases. In contrast, treatment of ERIS requests by transmission providers varies widely. This study adopts DEP's proposed approach for studying energy-only provisional interconnection service requests under contingency types P1 and P2.1 (zero DFAX threshold).[3] This standard for ERIS is more rigorous than some transmission providers, and if treatment was adopted similar to that of NYISO, CAISO, or ERCOT, network upgrade costs for ERIS would be expected to be lower.

1. Norris, T. H. 2023. Beyond FERC Order 2023: Considerations on Deep Interconnection Reform. NI PB 23-04. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University.
2. Exceptions exist in MISO/SPP for ERIS generators which separately procure firm transmission service.
3. DEC, DEP, & DEF Provisional Service Filings Update. April 19, 2024. Slide 11:
http://www.oasis.oati.com/woa/docs/CPL/CPLdocs/4.19.24_DEC_DEF_DEP_Provisional_Service_Filings_Update_Meeting_Presentation.pdf

Methodology

Summary: We replicated DEP's study results using DEP's data and assumptions, and then compared the results against a re-simulation assuming flexible energy-only interconnection service (ERIS).

Model: We used PowerGem's Transmission Adequacy & Reliability Assessment (TARA) software, a steady-state power flow simulation tool widely used by U.S. transmission providers, including most RTO/ISOs.

Data: We relied on the DEP RSC 2023 Phase 1 power flow models posted by DEP in May 2024 and did not modify any generator dispatch or load assumptions, and strictly utilized DEP-provided contingency and monitor files. 100% of the modeling data used to perform the analysis was DEP-provided; our analysis focused on applying DEP-data to understand how the RSC study results would have changed under a different study methodology using the same power flow modeling data.

Modeled scenarios:

- <u>Baseline Scenario: NRIS</u>: To replicate DEP's study and establish a baseline for comparison, we first modeled a scenario using equivalent contingencies and generation cases used by DEP for the RSC study.
- <u>Flexible Scenario: ERIS</u>: To assess the impact of flexible interconnection service, we then modeled a scenario applying the same contingency types proposed by DEP for energy-only provisional interconnection service (TPL-001 P1, P2.1), applied against all generation cases assessed by DEP, excluding the cases used by Duke for NRIS P3 analysis. All other inputs and assumptions were equivalent.

Cost estimation: We used DEP's estimates for the cost of each identified network upgrade, as specified in the RSC study. We only report an overload as mitigated if it is fully avoided based on the identified overload threshold, and only if it appears in the list of overloads in DEP's RSC study.

Sensitivities: We ran several sensitivities to assess the impact of certain assumptions, each of which is discussed in more detail following the primary results.

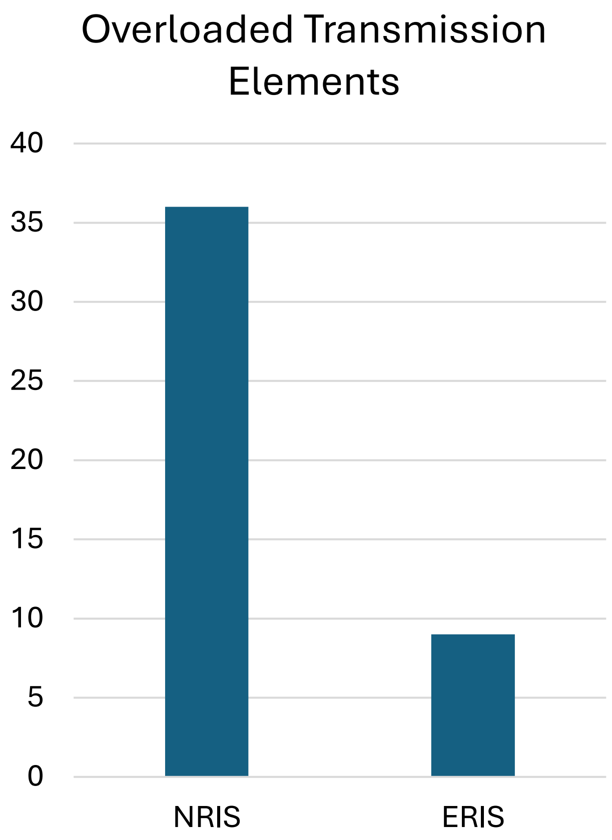
Paired storage: For the solar generators with paired storage, we did not treat them differently under the Baseline Scenario or Flexible Scenario as compared to the solar-only generators.

Results

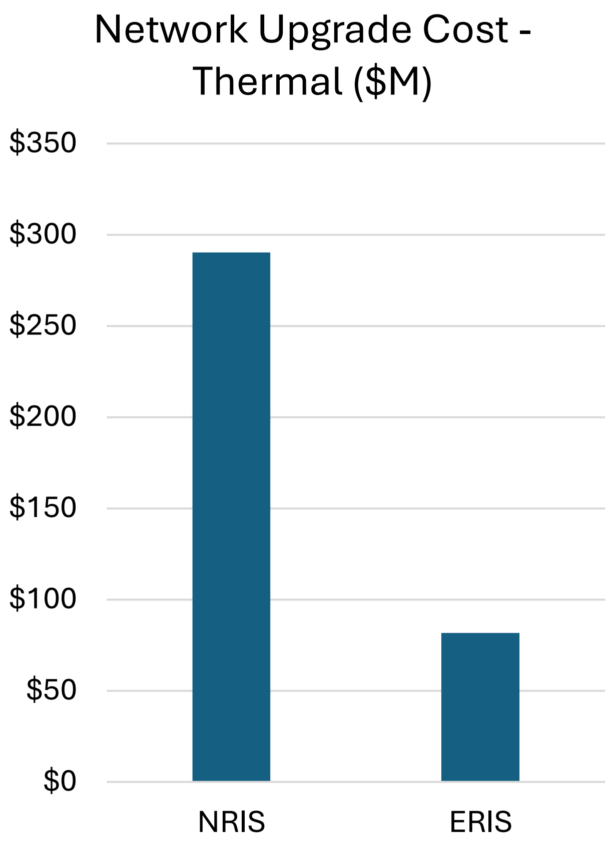
	Baseline Scenario: NRIS	Flexible Scenario: ERIS
Description	Reflects DEP's inputs and assumptions used to study the solar generators as NRIS, including all TPL-001 contingency types (P1-P7), including P3.	All inputs and assumptions were held fixed, except for the applied contingencies, which were updated to reflect DEP's proposed approach for studying energy-only provisional interconnection service (TPL-001 contingency types P1, P2.1).
Overloads	36 overloaded transmission elements*	9 overloaded transmission elements
Costs	$290 million in thermal network upgrades ($156/kW)*	$82 million in thermal network upgrades ($44/kW) *
Notes	Results reflect the deliverability test required by DEP based on local generation stress cases, which DEP refers to as "county stressed" or "county max" cases.	Results reflect the economic dispatch generation case provided by DEP, reflecting the ability to curtail ERIS generators with real-time congestion management.

* Based on DEP's cost estimate for each network upgrade required to mitigate each respective overload

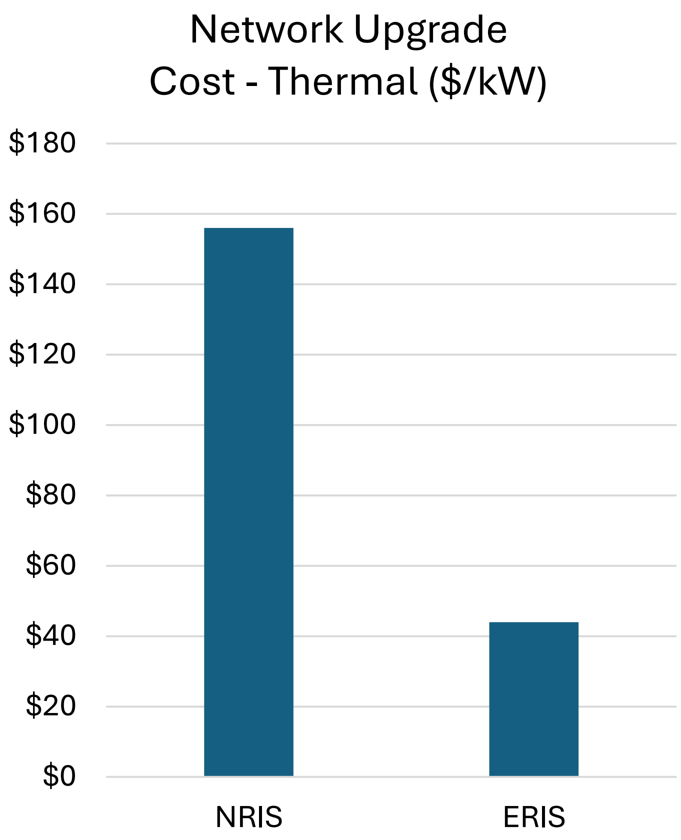
Results



Overloaded Transmission Elements
40
35
30
25
20
15
10
5
0
NRIS
ERIS



Network Upgrade Cost - Thermal ($M)
$350
$300
$250
$200
$150
$100
$50
$0
NRIS
ERIS



Network Upgrade Cost - Thermal ($/kW)
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
NRIS
ERIS

Sensitivities

We ran three sets of sensitivities to assess the impact of key assumptions:

- **Sensitivity #1**: Impact of overload thresholds
- **Sensitivity #2**: Impact of local stressed conditions
- **Sensitivity #3**: Impact of generator out of service (P3)

Sensitivity #1: Overload Threshold

Summary: We simulated the impact of using different loading thresholds for triggering network upgrades. In addition to DEP's 95% threshold, we simulated a threshold of 100%, 105%, and 110% to represent theoretical increases in weather adjusted equipment ratings, optimization of Duke's current facility rating methodology to improve equipment capability, and/or utilization of grid enhancing technologies.

Background:

- The current carrying capability of transmission elements (e.g. transmission lines, transformers) varies based on a variety of conditions. The rated limit of each element is based on several assumptions and safety standards, including overhead clearance for transmission lines (i.e. lines physically sag under higher current loading).
- To identify overloads in interconnection studies, DEP uses a threshold below the rated current carrying capability of the elements on its transmission system. Specifically, DEP uses a threshold of 95%, meaning that DEP requires a network upgrade when elements are loaded at or above 95% of each element's rated loading limit. This approach differs compared to many transmission providers, which often use a threshold of 100%.
- DEP does not publish its facility rating methodology and declined a request to provide one under CEII protection, therefore, it is not possible to evaluate DEP's method for determining its transmission element ratings to explore potential improvements. DEP generally does not utilize Short Term Emergency (STE) ratings that are common with other transmission providers to increase equipment capability during contingency events.
- Modern grid enhancing technologies (GETs) can enable higher current carrying capabilities for certain transmission elements, offering the potential for interconnection studies to use higher element ratings, avoid overloads, and reduce required transmission investment.

Sensitivity #1: Overload Threshold

Results:

	Baseline Scenario: NRIS			Flexible Scenario: ERIS		
Threshold	Number of Overloaded Elements	Count of Repeat Overloads (>1)	Cost ($M)	Number of Overloaded Elements	Count of Repeat Overloads (>1)	Cost ($M)
95%	36	8	$ 290.3	9	n/a	$81.6
100%	27	8	$ 252.6	8	n/a	$69.6
105%	17	6	$ 158.9	8	n/a	$69.6
110%	15	5	$ 138.3	8	n/a	$69.6

Discussion:

- For the NRIS scenario, the threshold has a significant impact on the number of identified overloads, particularly at 100% and 105%. Specifically, if a 105% threshold is attainable with optimized element ratings and/or GETs, 45% of thermal network upgrade costs are avoided compared to DEP's existing threshold (95%).
- For the ERIS scenario, a 100% overload threshold saves 15% of costs compared to a 95% overload threshold. The threshold is less impactful thereafter, due to the fact that utilization of ERIS already avoids a significant portion of overloads.
- If a more restrictive 95% threshold was used for NRIS compared to a less restrictive 100% threshold for ERIS, the ERIS cost savings compared to NRIS expand from 72% to 76% of total NRIS costs.

Sensitivity #2: Local Stress Cases

Summary: We simulated the impact of using strictly the economic generation dispatch case, rather than subjecting the projects to the full suite of cases required by DEP based on local generation stress cases.

Background:

- To assess the deliverability of generator interconnection requests, transmission providers often test local generator stress cases, in which electrically proximate generators within certain pockets of the system (including existing installed generators) are ramped up beyond their economic dispatch levels. In some cases, these proximate generators may be assumed to dispatch at their maximum potential output.
- DEP runs a large number of such local generation stress cases, which it refers to as “county max” or “county stressed” conditions. DEP states that these cases entail maximum output of local generators for each case, however, it isn’t documented which generators are included in each “county stressed” case or how realistic these system conditions are.
- Substantial latitude appears to exist in the assumptions that transmission providers use for these local generation stress cases.

Sensitivity #2: Local Stress Cases

Results:

	Baseline Scenario: NRIS		Flexible Scenario: ERIS	
	Local Stress Cases	Economic Dispatch Case	Local Stress Cases	Economic Dispatch Case
Number of Overloads	36	13	20	9
Cost	$ 290.3	$138.9	$168.4	$81.6

Note: results reflect DEP's 95% overload threshold

Discussion:

- DEP's local stress conditions appear to have greater impact on overloads and associated costs than any other single assumption in our study, driving approximately half of all identified network upgrade costs.
- Local stress tests are common for NRIS deliverability assessments, however, these results suggest that stakeholders may benefit from additional information regarding the specific assumptions used by some transmission providers.
- Although local stress conditions are generally not appropriate to apply against ERIS, if they are applied, these results suggest similarly large impacts, underscoring the need to confirm details of transmission providers' ERIS treatment.

Sensitivity #3: Generator Out of Service (P3)

Summary: We simulated the cost impact of the generator out of service contingency (TPL-001 P3) separately from the rest of the contingency types used for NRIS (P1, P2, P4-P7).

Background:

- The P3 contingency is simulation of a loss of a generator unit, followed by System Adjustments that may include "Transmission changes and re-dispatch of generation," followed by loss of another transmission element.
- The P3 contingency type may be applied by DEP in a way that creates unnecessary system stress by not utilizing the flexibility within the TPL-001 standard to mitigate issues through System Adjustments. Specifically, DEP assumes a uniform scaling of all area generators to replace the lost generation during the System Adjustment period. Whether intentional or not, this study process does not seek to minimize system stress and may lead to overloads and transmission investment that could be avoided with targeted redispatch.
- DEP could instead choose to redispatch the system to within its reliability limits to the extent that's economical, avoiding overloads and resulting transmission investment. DEP's assumption that all area generators will be scaled uniformly is a simplified method of simulating P3 contingencies and does not represent a targeted approach that seeks to minimize transmission investment. This change of methodology can be done within the current "System Adjustments" period defined by TPL while maintaining reliability and compliance.

Sensitivity #3: Generator Out of Service (P3)

Results:

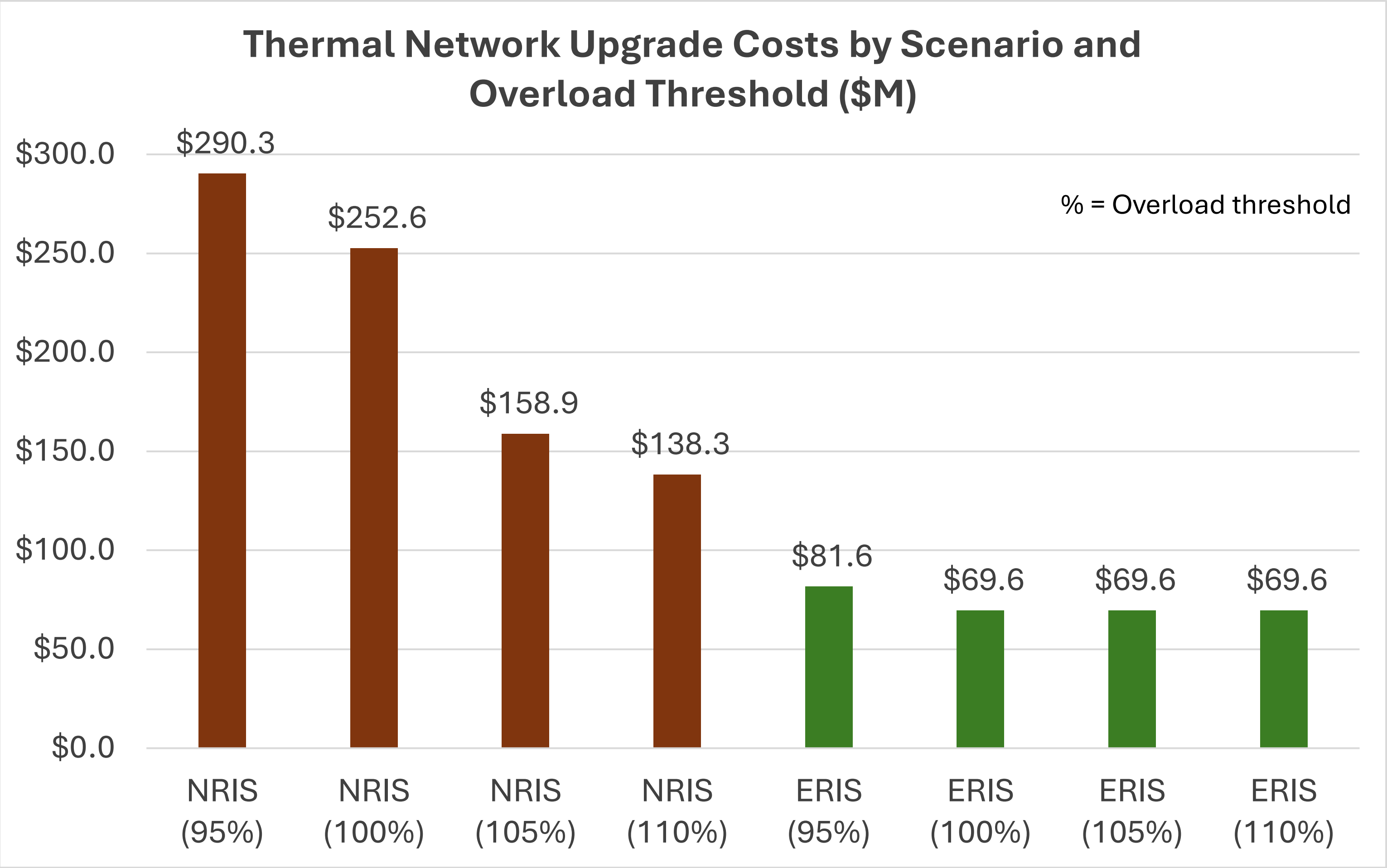
	NRIS excluding P3 Contingency			NRIS including P3 Contingency			Incremental Impact of P3		
Overload Threshold	Count of Overloads	Repeat Overloads (>1)	Cost	Count of Overloads	Repeat Overloads (>1)	Cost	Count of Overloads	Repeat Overloads (>1)	Cost
95%	34	17	$282.0	36	26	$ 290.3	2	9	$8.28
100%	25	13	$215.3	27	23	$ 252.6	2	10	$37.4
105%	17	11	$158.9	17	15	$ 158.9	0	4	$0
110%	15	11	$138.3	15	13	$ 138.3	0	2	$0

Note: results reflect DEP's local stress conditions

Discussion:

- In terms of overload count and cost in the context of DEP's RSC study, the P3 contingency can have significant impacts at certain thresholds and not in others. At an overload threshold of 100%, the P3 contingency is responsible for driving 15% of total thermal network upgrades.
- The impact of the P3 contingency is especially apparent with respect to the prevalence of the identified overloads, resulting in significantly more repeat overloads across the hundreds of simulated case-contingency pairs.

Summary of Results and Sensitivities



Appendix

Limitations

The results in this report reflect a good faith attempt to most accurately model the DEP 2023 RSC Phase 1 study under varying study methodologies to understand the impacts of specific changes of assumptions, and these results are unofficial by nature. Best efforts were made to rely on matching naming attributes, power flow results, and other available information to cross reference overloads between data sets. Some limitations of this study include the following:

- Most of DEP's study results could be replicated with a high level of confidence, but some overloads could not be reproduced based on DEP's provided inputs and assumptions, specifically P3 overloads, for unclear reasons. Of 44 relevant overloads, 36 were fully replicated; 4 were near-replicated, with slight differences in loading values; and 4 could not be replicated. These specific overloads were excluded from the analysis in this report to limit uncertainty.

- Naming conventions between DEP power flow models and the RSC are necessarily different at times due to character limitations in power flow software and the need to simplify results into a readable format within the RSC.

- Contingency analysis with TARA reported some overloads not identified in the RSC as requiring mitigation. These overloads were ignored and assumed to be outside the scope of the RSC, so only overloads that were both identified within the RSC and replicated with a high degree of confidence were included within this report.

- As previously noted, DEP's RSC study did not include stability or short circuit analysis. Similarly, this report did not seek to perform a stability or short circuit analysis.

Supplementary Analysis Opportunities

Areas for supplementary analysis include, but are not limited to:

Curtailment analysis

The impacts to curtailment of these alternative scenarios could be further investigated as part of a nodal production cost modeling run across ERIS vs. NRIS transmission upgrade scenarios to assess the impact of additional transmission investment required for NRIS service. This would help form a wholistic view on the value of transmission investment to avoid potential curtailment and estimate which mix of generating resources and transmission investment would result in the least cost delivered energy to consumers.

Contingency Sensitivities

Transmission providers often apply different sets of contingencies and loading impact thresholds (i.e. transfer distribution factors, DFAX) to ERIS in interconnection studies. Each of these assumptions could be simulated to compare against the assumptions used in this study, to inform considerations regarding an optimized approach to ERIS studies.

Paired storage

To account for paired battery energy storage systems (BESS), hybrid solar generators simulated as ERIS could be studied such that the BESS nameplate capacity is simulated as NRIS, to reflect its contribution as a capacity resource.

GRACE Lab

A Grid that is Risk-Aware for Clean Electricity

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Our research

Our research explores, assesses, and proposes technological, policy, and market approaches to contribute to the pursuit of environmental sustainability, affordability, reliability, and justice in the energy sector.

Primary research areas

- Characterizing sources of uncertainty that increase power systems' financial and reliability risk and designing risk management tools and strategies.
- Examining the attributes and characteristics of different electric power technologies and the possibilities and advantages of designing flexible policy mechanisms that consider the decision-making process and real options valued by those regulated.
- Assessing the economic, environmental, and reliability potential of renewable energy, storage, and emissions control technologies -- mainly related to their operational flexibility (e.g., use of different fuels, varying power output levels), the uncertainty that affects their outcomes, and the implications for the systems where they are integrated.

GRACE Lab is led by Dr. Dalia Patino-Echeverri, Gendell Family Associate Professor

https://sites.nicholas.duke.edu/daliapatinoecheverri