Are transmission cost allocation rules keeping low-cost renewable power off the grid?

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Introduction

In its January 2021 Executive Order, Tackling the Climate Crisis at Home and Abroad, the Biden administration established a 15-year timeframe to clean the U.S. energy grid. However, major stakeholders—including large utilities and independent power producers—refer to the goal of achieving 100% clean energy by 2035 as overly ambitious. There seems to be a consensus that technological breakthroughs may not materialize in time to meet the 2035 timeline. An equally formidable challenge will be to get the right policy, planning, and cost allocation mechanisms in place to enable deployment of large-scale transmission necessary to reliably move clean energy from places where it's produced to places where it's needed most.

This paper discusses an aspect of transmission planning that is significantly affecting the ability to add new renewable generation to help meet clean energy goals—the generation interconnection process. In particular, ICF's recent study of the benefits of network upgrades demonstrates that it is reasonable for stakeholders to rethink the cost allocation process for the transmission projects needed to integrate renewable generation into the grid.

Achieving the 2035 clean energy goal will require significant amounts of renewable generation. Because these resources usually cannot be located close to the load centers, transmission capacity will be required to move the power to areas where it will be used. This raises several issues:

- The transmission system in several locations favorable to the development of new renewable resources is oversubscribed. This means significant amounts of new transmission capacity will need to be built.
- The current regional transmission planning process does not support the development of the large regional and inter-regional transmission capacity that will be needed. Generation developers are increasingly required to build large transmission facilities as network upgrades. The generation interconnection process is replacing some aspects of the regional transmission planning process.
- Further exacerbating the situation, the current cost allocation rules in several of these regions are saddling generation developers with the cost of these new transmission projects.

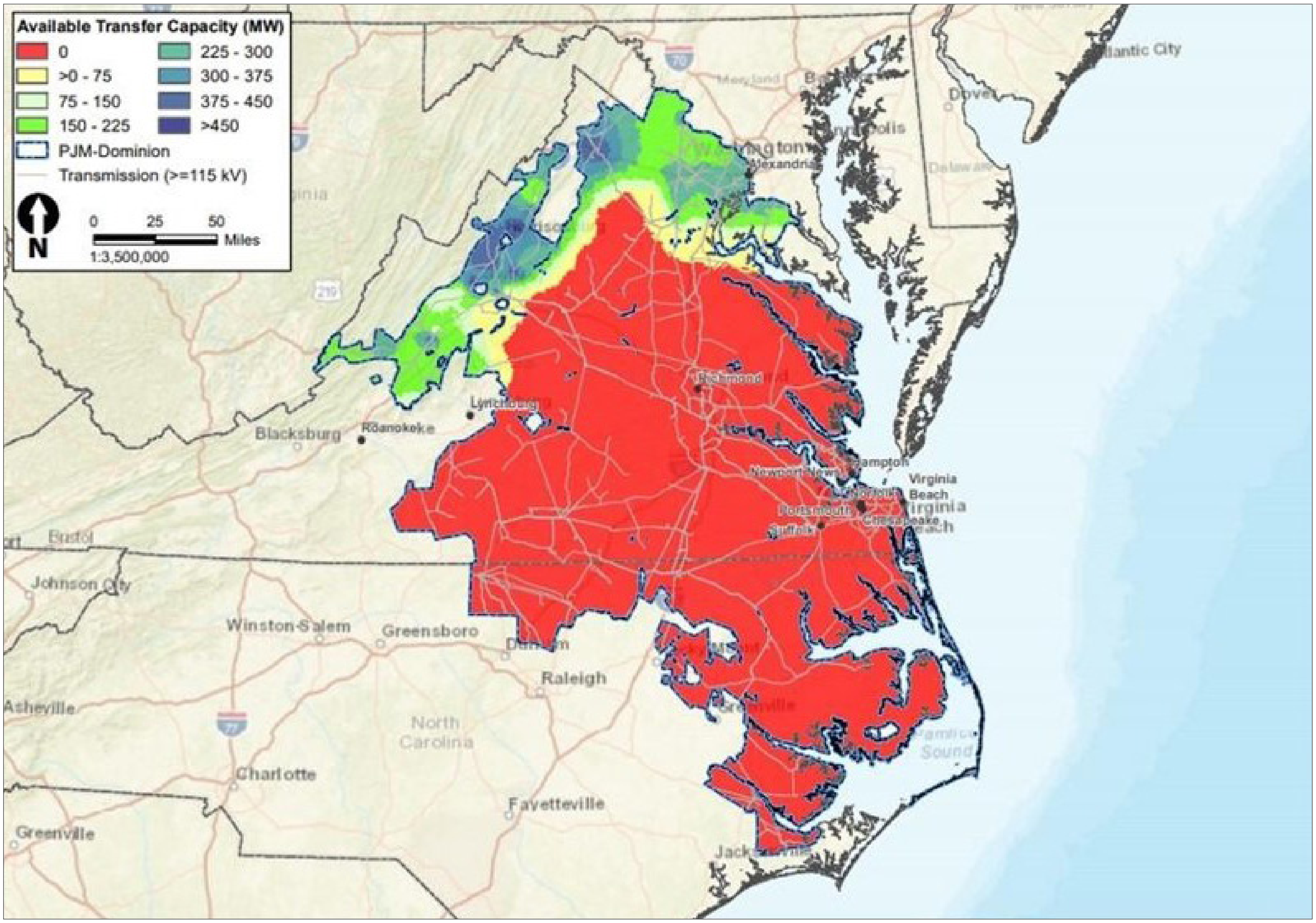
An oversubscribed transmission system

In its recent Advance Notice of Proposed Rulemaking (ANOPR) presenting potential reforms to improve the electric regional transmission planning and cost allocation and generator interconnection processes, the Federal Energy Regulatory Commission (FERC) notes that "there is little remaining existing interconnection capacity on the transmission system, particularly in areas with high degrees of renewable resources that may require new resources to fund interconnection-related network upgrades that are more extensive and, as a result, more expensive ."[1]

ICF's review of available transmission capacity across various markets shows significant chokepoints and very limited capacity to interconnect future renewables. For example, Exhibit 1 shows the results of ICF's analysis of available transmission capacity for interconnection of new generation in PJM's Dominion load zone by 2025. The Virginia Clean Energy Act, which was passed into law in 2020, requires that the state add approximately 25 GW of renewables, including offshore wind, by 2035. The heat map shows significant chokepoints across the entire Dominion load zone with virtually no available capacity to interconnect in most of the zone. Areas with available injection capacity are close to the urban populations in Northern Virginia, where there is very limited land availability to develop large-scale renewables. ICF observes such limitations in other load zones in PJM and other markets, especially SPP and MISO.

[1] Federal Energy Regulatory Commission, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Advance Notice of Proposed Rulemaking, Docket No. RM21-17-000, July 15, 2021

Exhibit 1: Available injection capacity – PJM Dominion (2025)



Source: ICF Analysis

An examination of the generation interconnection queue in several regions confirms the logjam in markets where renewables represent a major portion of the resources under active development. For example, there is upwards of 350 GW of active renewable capacity[2] across interconnection queues of MISO, SPP, and PJM. All three market operators are already significantly delayed in processing these large queues. As shown in Exhibit 2, the estimated time for a generator to achieve a Large Generator Interconnection Agreement (LGIA) ranges from approximately 2.5 years in MISO to over 4.5 years in SPP. This timeline assumes the Phase I study was initiated by the respective ISOs. All three ISOs have significant delays in initiating the study process. For example, SPP is currently evaluating projects that entered the queue in 2017 and has indicated it would take at least eight years or more to clear the backlogged cluster studies.

[2] Renewable capacity comprises of wind, solar, standalone storage, and hybrid resources

Exhibit 2: Current state of the interconnection queues of MISO, SPP, and PJM

Market	Renewable capacity[3]	Estimated time to achieve LGIA[4]
MISO	138 GW[5]	3–5 years
SPP	96 GW	4–8 years
PJM	125 GW	3–5 years

Source: Compiled by ICF based on generator queue from all Independent System Operators (ISO/RTO)

Is the generator interconnection process becoming a de facto regional transmission planning process?

In recent years, generation interconnection studies identified network upgrades that are effectively large regional transmission projects. The following is a selection of extra-high-voltage transmission upgrades amongst several hundred network upgrades identified through the interconnection study process in MISO, PJM, and SPP:

MISO

- $407 million, 200-mile, 345kV line from Center to Ellendale, assessed for approximately 1.2 GW of new capacity in MISO's 2017 DPP August West Cycle
- $312 million, 90-mile, 500kV line from Franklin to Baxter Wilson, assessed for approximately 5.4 GW of new capacity in MISO's 2018 April South DPP Cycle
- $1.3 billion, several 345 kV, and other upgrades to mitigate stability issues on Minnesota Wisconsin Export Interface (MWEX) assessed for approximately 3.4 GW of new capacity in MISO's 2017 DPP February West Cycle

SPP

- $1.3 billion, 165-mile, 765-kV Double Circuit line from Crawfish Draw to Seminole, assessed for approximately 6.8 GW of new capacity in SPP's DISIS-2017-001
- $275 million, 150-mile, 345-kV line from Post Rock to Red Willow, assessed for approximately 3.1 GW of new capacity in SPP's DISIS-2016-002
- $220 million, 30-mile, 345-kV line from Antelope to Holt, assessed for approximately 4.9 GW of new capacity in SPP's DISIS-2016-002

[3] Includes active wind, solar, standalone storage, and hybrid resources in the queue
[4] Estimated time includes the delay in initiating the study process
[5] Includes 72.6 GW of renewable generation that entered the 2021 DPP cycle across all MISO sub-regions

PJM

- Approximately $400 million, 110-mile, 500-kV new line from Rawlings to Morrisville (n6539), assessed for approximately 1.9 GW of new capacity in PJM's AE1-AE2 Clusters
- Approximately $128 million, 42-mile, 500-kV line rebuild from Midlothian to North Anna (n5609), assessed for approximately 1.3 GW of new capacity in PJM's AE1-AE2 Cluster

The cost allocation burden

To make matters worse, cost allocation rules for network upgrades assign most, if not all, of the cost of the network upgrades to the generation developer. Exhibit 3 is a summary of the cost allocation rules in MISO, PJM, and SPP. In MISO, generators pay 90% of the cost of network upgrades for projects rated 345 kV or higher, while load (consumers) pay 10% of the cost. For all other projects, costs are assigned entirely to the generator.

Exhibit 3: Current cost allocation rules for GI-related network upgrades

Market	Load	Interconnection customer
MISO	10% | >= 345 kV 0% | < 345 kV	90% | >= 345 kV 100% | < 345 kV
SPP	0%	100%
PJM	0%	100%

The enormity of these network upgrades is too much for a particular cluster of projects to accommodate, which leads to queue withdrawals and subsequent restudies. This is one of the major reasons for the delays in the generation interconnection process.

Interestingly, FERC acknowledges in the ANOPR that "the more significant the interconnection-related network upgrades needed to accommodate a new resource, the greater the potential that such upgrades may benefit more than just the interconnection customer." FERC also expresses concerns that if the interconnection customer decides not to pursue a particular generating facility (or facilities) given the scale of the allocated costs and for upgrades expected to provide significant system-wide benefits, the "net beneficial infrastructure would not be developed, potentially leaving a wide range of customers worse off as a result."

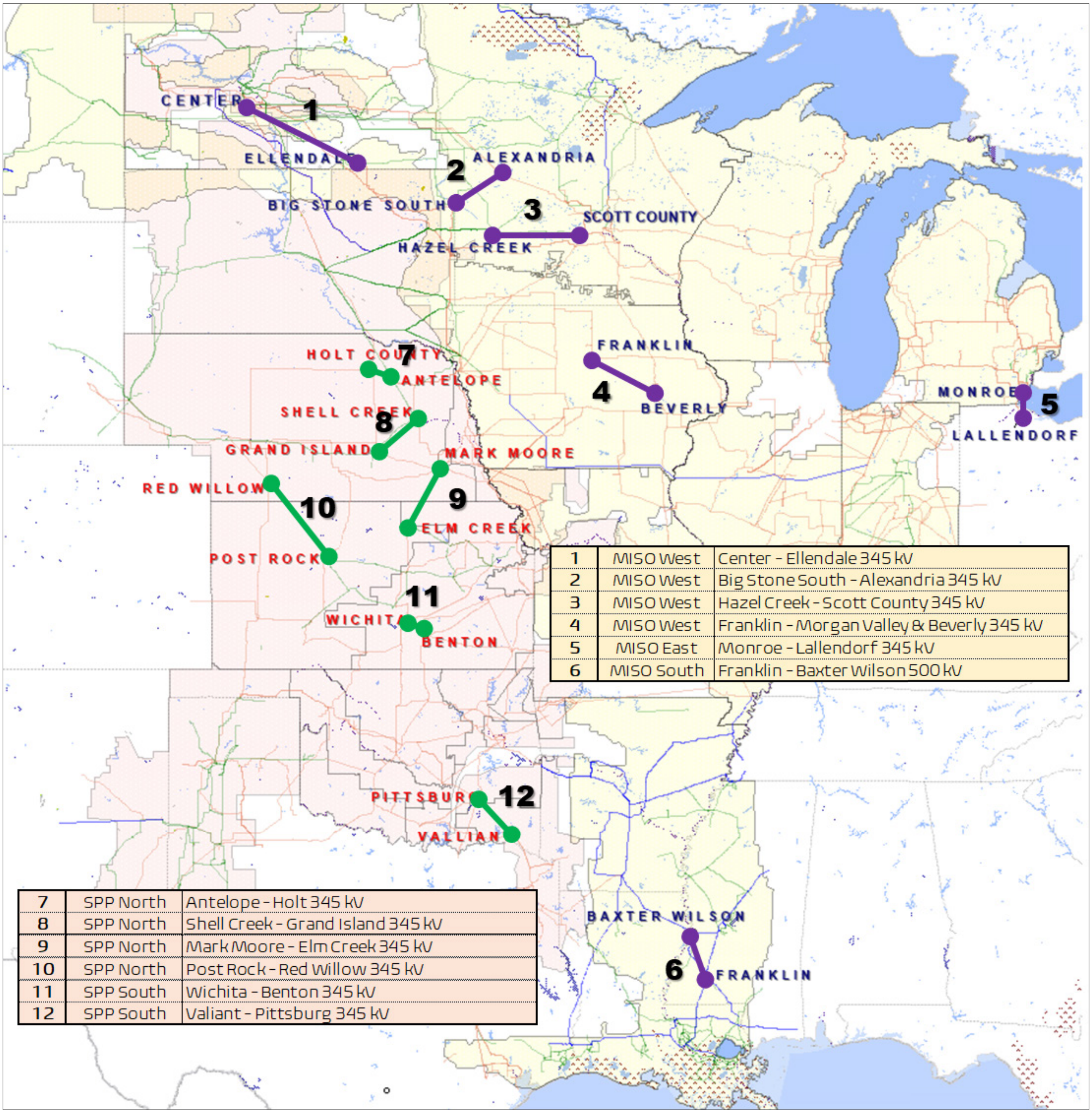
Given the potential for such benefits, assigning all of the cost to the generation developer could result in a mismatch between the costs and benefits to the consumer.

Assessing the benefits of network upgrades

In an effort to quantify the extent, if any, of interconnection-funded network upgrades, ICF recently supported American Council on Renewable Energy (ACORE) by performing a detailed production cost analysis. This analysis of several network upgrades in MISO and SPP assigned to interconnection customers assesses if those upgrades provided any savings to the load beyond their primary goal of reliably interconnecting the new supply to the grid. Using very conservative assumptions, this study evaluated the economic benefits of a representative sample of network upgrade projects[6] assigned through the MISO and SPP GI process over the last seven years. During its analysis, ICF screened over 600 projects using a set of selection criteria informed by a range of factors, including voltage class, location of the upgrades, and generation interconnection capacity (spread across various study clusters), all allocated to the network upgrades. The screened network upgrades across both RTOs were shortlisted to six network upgrades in each RTO. Exhibit 4 shows the geographic location of the selected projects. The results demonstrate that several of the somewhat randomly selected network upgrades provided significantly more benefits than those reflected by the current costs allocated to the shared system.

[6] ICF relied on past DISIS and DPP studies for SPP and MISO, respectively, to shortlist a pool of network upgrades evaluated as part of the study. The details of the screening processes are described in the Study Design section of the report.

Exhibit 4: Approximate location of the assessed network upgrades



1	MISO West	Center - Ellendale 345 kV
2	MISO West	Big Stone South - Alexandria 345 kV
3	MISO West	Hazel Creek - Scott County 345 kV
4	MISO West	Franklin - Morgan Valley & Beverly 345 kV
5	MISO East	Monroe - Lallendorf 345 kV
6	MISO South	Franklin - Baxter Wilson 500 kV

7	SPP North	Antelope - Holt 345 kV
8	SPP North	Shell Creek - Grand Island 345 kV
9	SPP North	Mark Moore - Elm Creek 345 kV
10	SPP North	Post Rock - Red Willow 345 kV
11	SPP South	Wichita - Benton 345 kV
12	SPP South	Valiant - Pittsburg 345 kV

Source: ICF, Interconnection Studies from SPP and MISO

ICF and ACORE relied on Adjusted Production Cost (APC) savings[7] and benefit-to-cost (B/C) ratio[8] as metrics to assess the impact of the 12 network upgrades, noting that APC savings and B/C ratios are typically the most common metrics to evaluate economic upgrades. Of the 12 upgrades selected across both MISO and SPP, 10 provided positive APC savings and two demonstrated benefits far in excess of their costs, indicating that those projects could potentially be classified as economic upgrades. However, network upgrades assigned to GI projects are not designed as market efficiency projects. The primary goal of the GI-funded network upgrades is to reliably interconnect the new resources to the grid. This goal assumes that transmission planning processes are sufficiently forward-looking to address the broader regional chokepoints these generation projects may face. Put another way, this objective assumes the highway access is available and, for the most part, new generators would only fund the costs of building a driveway.[9]

Given the over-subscribed state of the power grid, the GI customer is now forced to fund not just the driveway, but also the highway. Because the APC savings are a measure of the benefits to the system, the appropriate comparison should be to the cost allocated to the load. ICF observed a combined $450 million of net benefits to MISO and $350 million of net benefits to SPP for the six transmission upgrades assessed in each market.

[7] APC Savings (or Benefits) is one of the most commonly used metrics to assess the economic benefits of transmission projects. APC is calculated as the total of production costs of a generation fleet within a region adjusted by transaction costs. The production cost includes fuel costs, operations and maintenance costs, startup costs, and cost of emission allowances. The transaction cost includes purchases and/or sales within the region and between the region and other regions. APC Savings are calculated as a delta between APC with and without the transmission project of interest.

[8] Benefit-to-cost (B/C) ratio is estimated as annualized APC savings divided by cost of the individual transmission project. In most markets, B/C ratio of transmission projects should be >=1 to be considered as economic or market efficiency projects. In MISO, market efficiency projects must meet a B/C ratio of at least 1.25 to be approved. SPP uses a B/C ratio threshold of 1.0 for market efficiency projects.

[9] Also known as direct attachment or direct interconnection costs

Exhibit 5: Aggregate net benefits to load (Million $)

Metric	MISO	SPP
Cost allocated to load	191	0
APC savings	642	351
Net benefits	451	351

Details for individual projects can be found in the study.

The projected net benefits assessed in this study were solely attributed to production cost savings and did not attempt to capture additional benefits transmission upgrades provide, including any societal economic benefits/jobs, reduced cost of extreme events, etc. Importantly, the ICF study used the most conservative of the MISO and SPP future scenarios. For example, ICF used MISO's Future I, which factored in a carbon emissions reduction of 40%. Future II and Future III reflected 60% and 80% carbon emissions reduction respectively and had significantly higher renewable penetration. The benefits of the network upgrades are expected to be greater as more renewable-sourced electricity is injected into the grid. This also demonstrates another type of unrecognized benefit of network upgrades. Once built, these upgrades would enable additional generation to enter the queue in the future and interconnect at no incremental cost to the future builds or consumers.

Conclusion

While ICF's report analyzed a small sample of transmission network upgrades in MISO and SPP, many of the extra-high-voltage network upgrades—currently cost allocated to interconnection customers—provide broader regional economic benefits resulting in real value to consumers. However, the current approach leading to high network upgrade costs has become a significant hurdle for the integration of low-cost new renewable generation. Understanding these potential areas of consumer benefits can help policymakers and other stakeholders determine how to leverage such projects to the advantage of customers while ensuring equitable cost allocation.

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Himali joined ICF in 2002 and leads the Interconnection and Transmission practice at ICF. Her areas of focus are renewable integration, grid interconnection, production cost modeling, transmission congestion and losses, and their effect on locational power prices and asset valuation. She regularly provides financing and lending agencies with an independent and unbiased view of the future market and grid conditions and the economic viability of individual assets. Himali closely follows interconnection and transmission issues and proposed transmission plans across various power markets and performs independent assessments of reliability issues on the grid.

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