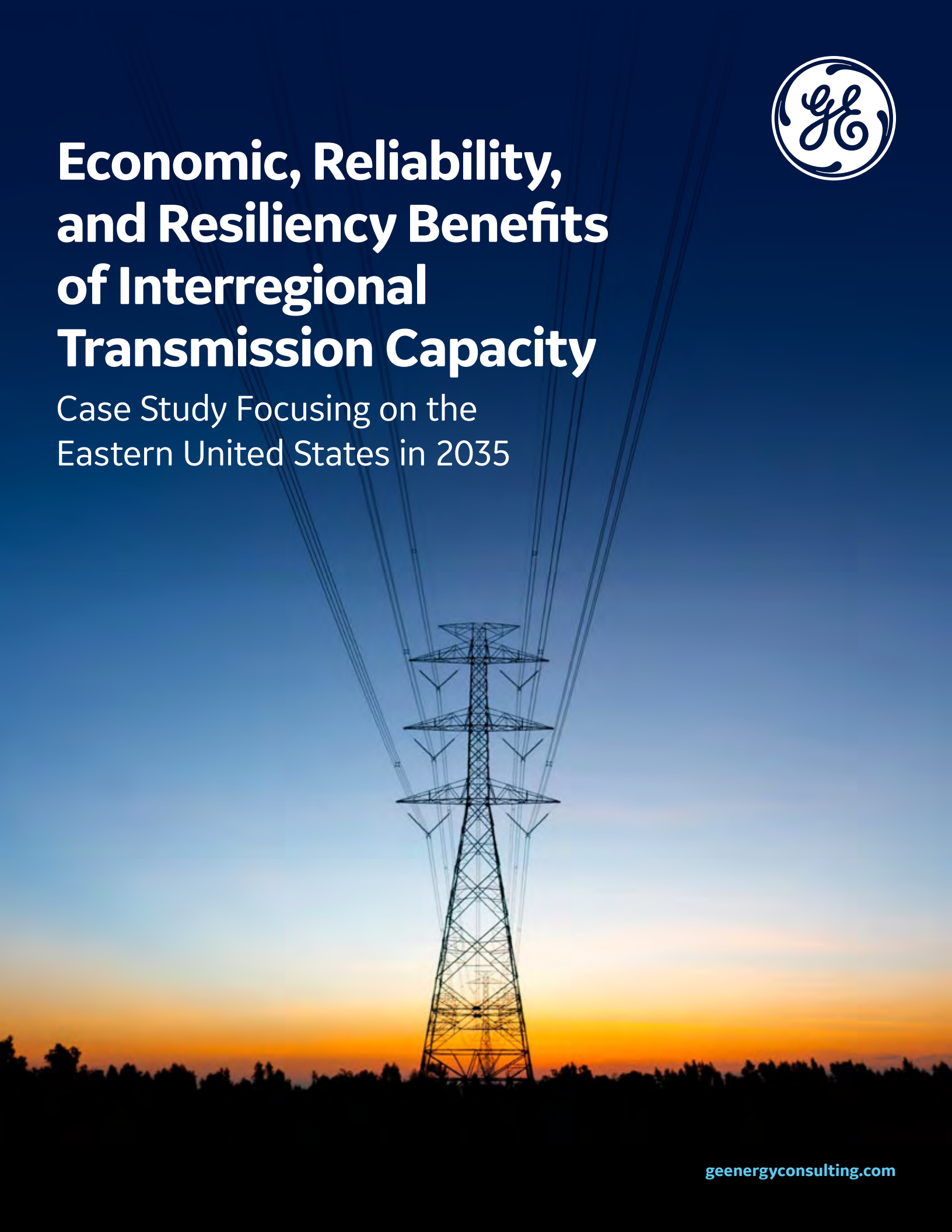
Economic, Reliability, and Resiliency Benefits of Interregional Transmission Capacity

Case Study Focusing on the Eastern United States in 2035



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FOREWORD

This report was written on behalf of, and funded by, the Natural Resources Defense Council (NRDC). It was prepared by General Electric International, Inc. (GEII), acting through its Energy Consulting group, based in Schenectady, New York. Questions and any correspondence concerning this document should be referred to:

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Relevant Engineering Terms & Acronyms

AC / DC	Alternating Current / Direct Current
EI	Eastern Interconnection
FRCC	Florida Reliability Coord
FERC	Federal Energy Regulatory Commission
GE MAPS	GE Multi Area Production Simulation
GW / MW	Gigawatt / Megawatt
Hz	Hertz
ISONE	Independent System Operator of New England
kV	Kilovolts
LMP	Locational marginal price
MISO	Midcontinent Independent System Operator
MMBtu	Metric Million British Thermal Units
NYISO	New York Independent System Operator
PJM	Pennsylvania New Jersey Maryland Regional Transmission Organization
POI	Point of Interconnection
PV	Present value
SCR	Short circuit Current Ratio
SERC (E, SE, N)	Southeastern Electric Reliability Council (East, Southeast, North)
SPP	Southwest Power Pool

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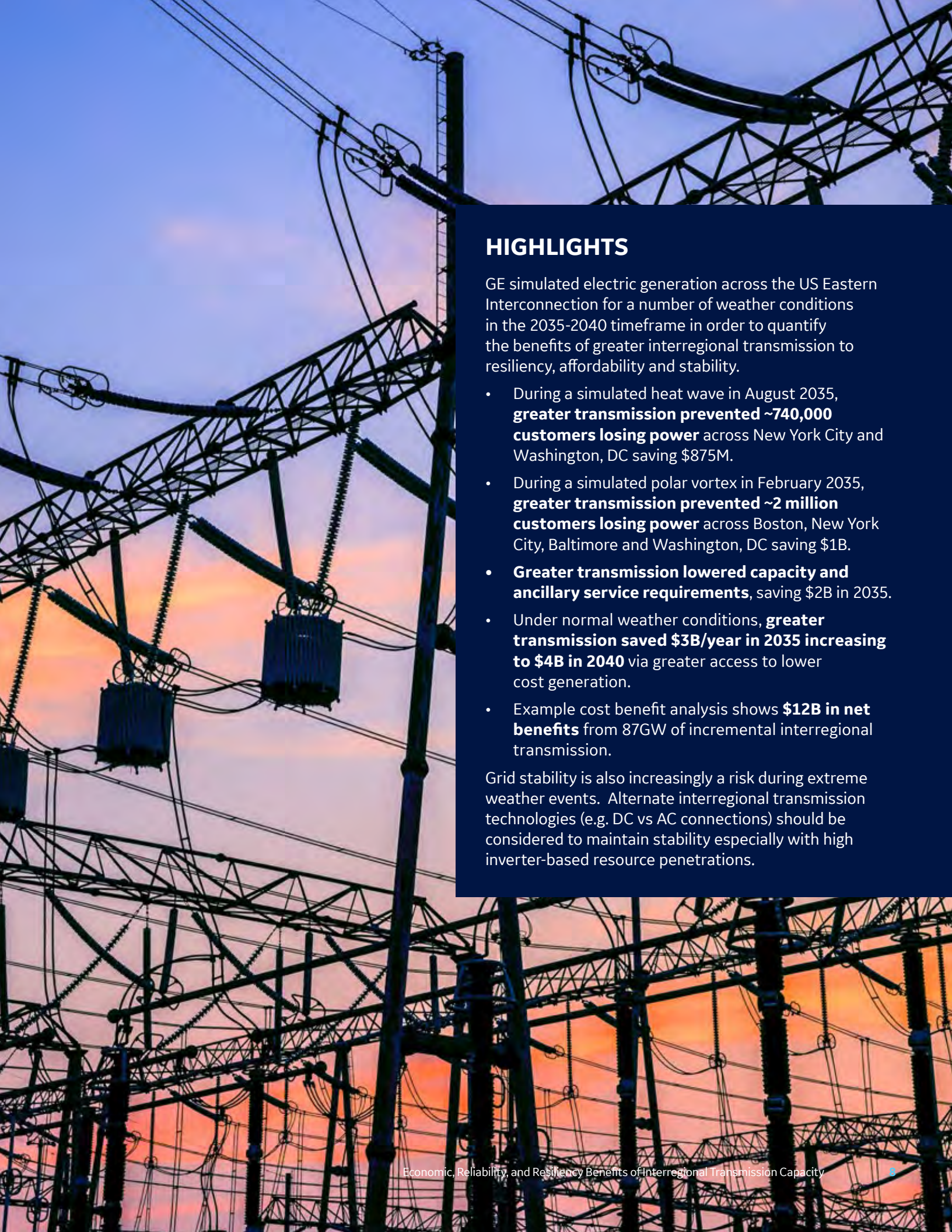


HIGHLIGHTS

GE simulated electric generation across the US Eastern Interconnection for a number of weather conditions in the 2035-2040 timeframe in order to quantify the benefits of greater interregional transmission to resiliency, affordability and stability.

- During a simulated heat wave in August 2035, **greater transmission prevented ~740,000 customers losing power** across New York City and Washington, DC saving $875M.
- During a simulated polar vortex in February 2035, **greater transmission prevented ~2 million customers losing power** across Boston, New York City, Baltimore and Washington, DC saving $1B.
- **Greater transmission lowered capacity and ancillary service requirements**, saving $2B in 2035.
- Under normal weather conditions, **greater transmission saved $3B/year in 2035 increasing to $4B in 2040** via greater access to lower cost generation.
- Example cost benefit analysis shows **$12B in net benefits** from 87GW of incremental interregional transmission.

Grid stability is also increasingly a risk during extreme weather events. Alternate interregional transmission technologies (e.g. DC vs AC connections) should be considered to maintain stability especially with high inverter-based resource penetrations.

1 EXECUTIVE SUMMARY

The United States electric grid is in a state of transition. The country is shifting towards lower carbon sources while facing more frequent extreme weather events that challenge the ability to keep the lights on. Greater grid flexibility is the key to reliable decarbonization in the face of uncertainty. One of the most cost-efficient forms of flexibility while maintaining resiliency is greater reliance on interregional imports and exports of electricity.

GE Energy Consulting (GE) knows the value of interregional flexibility from its own study experience. Back in our 2010 Western Wind and Solar Integration Study, GE and the National Renewable Energy Laboratory (NREL) identified the value of higher inter-regional flexibility to support California's decarbonization goals. This work helped support the 2014 launch of the Western Energy Imbalance Market that is operating today and has enabled over $2B in gross benefits across its 17 members.

In this study, we broaden our perspective to ask and illustrate the more general question: What are the benefits of interregional transmission? Answering this question should be based on the three types of ratepayer benefits:

1

Resiliency

Interregional transmission expansion can lower the overall capacity required given grid uncertainty. In the face of frequent and extreme weather events, interregional transmission expansion can allow access to generation that otherwise would not have been accessible and minimizes the likelihood (or in the worst case, the impact) of shedding load (i.e., blackouts). In addition, a reduction in overall generating capacity is needed as interregional capacity takes advantage of diversity in load shapes.

2

Affordability

Interregional transmission expansion allows ratepayers with expensive generation to access generation from areas with less expensive generation. By enabling greater transmission access to these low-cost resources, ratepayers with more expensive generation can benefit.

3

Stability

With the shifting generation mix comes increased reliance on inverter-based resources. Interregional capacity can strengthen voltage, which is especially important for regions with large amounts of high inverter-based resources. Interregional transmission can reduce the amount of generation capacity that is required for meeting such stability needs.

In this study, GE modeled generation differences between a transmission-constrained and an unconstrained transmission grid to estimate the resiliency, economic and stability benefits. **GE found that fully unconstraining the transmission system in the Eastern Interconnection (EI) would result in limited to no loss of load during extreme weather events and $12 billion in net benefits.** GE believes these benefits are conservative due to a number of factors including:

- Study evaluated average power flows between regions rather than maximum power flows;
- Study assumed all regions maintained resource adequacy, and for estimating capacity and ancillary service savings, assumed a flat reserve margin rather than conducting a loss-of-load-expectation analysis;
- Many assumptions in GE's production cost model were locked in place in April 2022 to maintain the integrity of the comparative analysis conducted for this study. Had the study included 2022 updates to load forecasts, which incorporated more aggressive electrification assumptions by Independent System Operators, and most recent natural gas price forecasts, GE believes the benefits would have been higher.

Nevertheless, the benefits of interregional transmission are significant and are highlighted in this study.

GE also recognizes that the production cost modelling conducted for this study assumes rational economic behavior and that all stakeholders in the Eastern Interconnect would utilize the increased transmission capacity by increasing exports and imports to and from neighboring regions. There are a number of operational and planning limitations which could limit the realization of potential benefits of increased interregional transmission. Examples of limitations could include operational governance of the commitment and dispatch decisions of imports and exports in both day-ahead and real-time markets; planning requirements limiting imports to serve a regional grid in all but the most limited circumstances; and sharing of resources to meet reserve margins across multiple jurisdictions. This study is designed to exemplify the benefits of increased interregional transmission and does not specifically address potential barriers to those benefits.

2 METHODOLOGY & ANALYSIS

GE utilized the following approach based on interregional power flow needs and benefits across three sources of value:

1 Resiliency

That level of interregional transmission enables load to be served during expected extreme weather events across the Eastern Interconnection?

2 Affordability

What level of interregional transmission enables the most economic use of generation to serve load across the Eastern Interconnection?

3 Stability

Should interregional transmission include attributes beyond the size of AC transmission capacity? Given that grid stability is increasingly a factor during extreme weather events, how should interregional transmission address this concern?

In the following sections, GE outlines its evaluation methodology for each of these three areas and illustrate its use with an example analysis focused on the Eastern Interconnection of the United States.

2.1 Benefits of incremental interregional transmission for increased resilience

2.1.1 Methodology

2.1.1.1 Formulate future system base assumptions

Future interregional supply-demand scenarios form the foundation of the simulations GE proposes to determine the benefits of interregional transmission. Many planners focus their simulations on their own region with limited or simplified consideration of the neighboring regions. However, in order to accurately assess the benefits of interregional transmission, a full grid model of the interregional system in question needs to be in place with future assumptions regarding variables such as:

1. Generation mix, additions & retirements
2. Annual load growth
3. Hourly load profile
4. Hourly renewables profiles
5. Generation cost assumptions including plant-level fuel costs
6. Interregional nodal transmission system and its constraints

New York City blackout after Hurricane Sandy, October 2012

2.1.1.2 Formulate future resilience conditions

For extreme weather uncertainty, GE proposes developing uncertainty scenarios to test for the amount of incremental transmission needed given potential load spikes, generation outages, or fuel shortages. For the case study presented, GE simulated individual scenarios. Ideally, GE recommends a more detailed stochastic analysis of the impacts from these variables if additional study funding becomes available. These requirements would be calculated on a pool-to-pool basis for each pool across the United States.

Given that recent grid events have highlighted adequacy risks across every type of resource (e.g., frozen cooling water, gas supply outages, transmission outages, extreme temperatures), the study team suggests that this type of analysis would:

- **Broaden the potential sources of failure** (e.g., non-electric sources of failure such as gas supply outage)
- **Test new weather extremes** (e.g., extreme temperatures driving extreme load peaks)
- **Test coincidence of failures** (e.g., extreme temperatures during gas supply failure, or cyber-attacks across multiple resources simultaneously)

2.1.1.3 Simulate future extreme-weather system performance with constrained vs unconstrained transmission

With the resilience conditions established, GE proposes simulating system performance under the following two transmission conditions:

1. Condition 1: **Constrained transmission.** This will allow the determination of the average power flow amounts between pools utilizing the existing/planned transmission system.
   Output metric: Average constrained power flows for each pool-to-pool interface.
2. Condition 2: **Unconstrained transmission.** For this simulation, GE suggests removing the MW limits associated with transmission flows. By removing the transmission line limits, the average power flows between pools can be determined to serve load most economically across the EI.
   Output: Average unconstrained power flows for each pool-to-pool interface.

Utilizing simulations under both the constrained and unconstrained EI conditions allows us to calculate the amount of transmission necessary to ensure resiliency:

Resilience incremental interregional transmission requirement

= Max across resilience scenarios [Average unconstrained power flows

- Average constrained power flows]

Equation 1 - Formula for calculating the resilience incremental interregional transmission requirement.

2.1.2 Example analysis for the US Eastern Interconnection

GE used the methodology above to estimate the amount of incremental transmission needed for the EI in 2035 to demonstrate resiliency benfits.

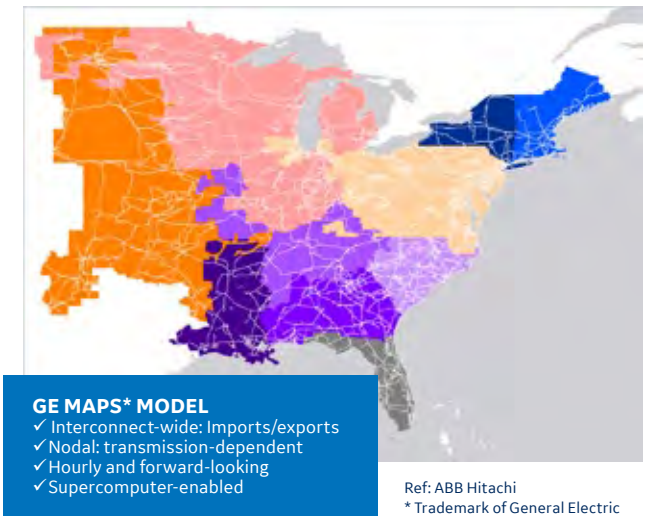


Figure 1 - GE simulation approach used GE MAPS to simulate the hourly dispatch across the EI in 2035.

GE simulated hourly dispatch across the EI in GE MAPS. Please refer to Section 4 for a summary of the assumptions used.

2.1.3 Example resilience analysis: Load shedding is mitigated via expanded transmission

2.1.3.1 Extreme Weather Events

Two weather events—a summer heat wave and a polar vortex—were simulated. Ideally, a broader range of resilience conditions would be considered either through many scenarios or using stochastic analysis. Such a broad range of grid conditions was considered beyond the scope of this analysis. However, the two extreme weather examples simulated here show the value of greater interregional transmission.

GE designed two extreme weather events to be simulated in this example:

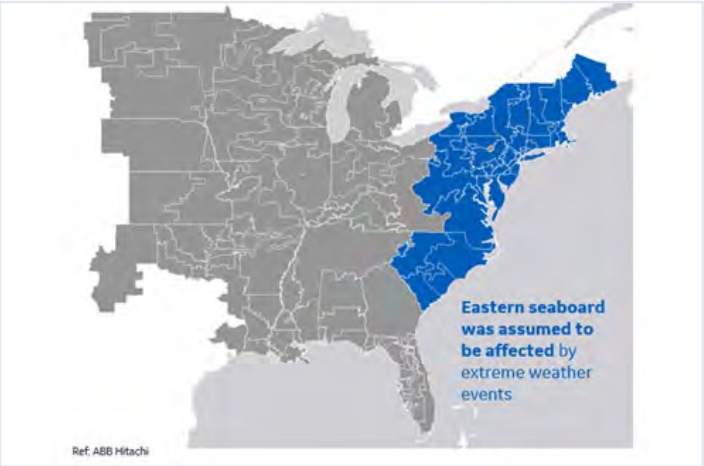


Figure 2 - For this example analysis, GE assumed that the Eastern seaboard was affected by the two extreme weather events we designed.

1

2035 Summer Heat wave

This event was modeled after the three-day summer heat wave of August 2018 where load along the East Coast was ~30% higher than average due to extreme heat. For this simulated event, GE therefore assumed an hourly load shape that was 30% higher than our assumed normal weather hourly load shape for the weekdays 8/15/2035 through 8/17/2035. For the days before and after the event, GE assumed hourly load was 10% higher than normal.

2

2035 Polar Vortex

This event was modeled after the February 2014 Polar Vortex event where East Coast load was ~40% higher than normal along with generation outages due to the cold. Winter loads are generally lower than summer loads, but the coincidence of generation outages adds another resiliency challenge. For this simulated polar vortex event, GE assumed:

- **Higher hourly load:** The hourly load shape was 40% higher than our assumed normal weather hourly load shape for the weekdays 2/14/2035 through 2/16/2035. For the days before and after the event, we assumed hourly load was 10% higher than normal.
- **Generation outages:** GE assumed ~15% generation outages across all fuel types due to winter conditions.
- **Gas price spikes:** Due to higher heating loads, the example also assumed gas prices spike to $40/MMBTU due to supply shortages.

2.1.3.2 Heat wave analysis: Unconstraining transmission eliminates loss of load

In this example heat wave, GE simulated the EI under both a constrained and an unconstrained transmission system. The results of this simulation are shown in Figure 3.

Figure 3 shows average locational marginal prices (LMPs) across the EI during the 3 heat wave days in August 2035 for both the constrained and unconstrained conditions. In the constrained transmission case, regional LMPs across the EI spike to greater than $300/MWH in the New York City and Washington, DC metropolitan areas whereas given the greater access to generation in the unconstrained transmission case, prices remain tempered at ~$60/MWH. The arrows connecting each pool in Figure 3 denotes the average power flow size and direction between pools. As Figure 4 shows, in the unconstrained case, average power flows are significantly larger than in the constrained case. These larger average power flows enable more levelized prices.

More importantly, in the constrained case shown in Figure 3, given the increase in load and in transmission constraints, 35 GWh of power is lost, which is equivalent to ~740,000 customers losing power across New York City (~600,000 customers) and Washington, DC (~140,000 customers). Assuming $25k/MWH loss of load cost, this loss of load event equates to $875M. **By unconstraining the transmission system, these load losses are eliminated.**

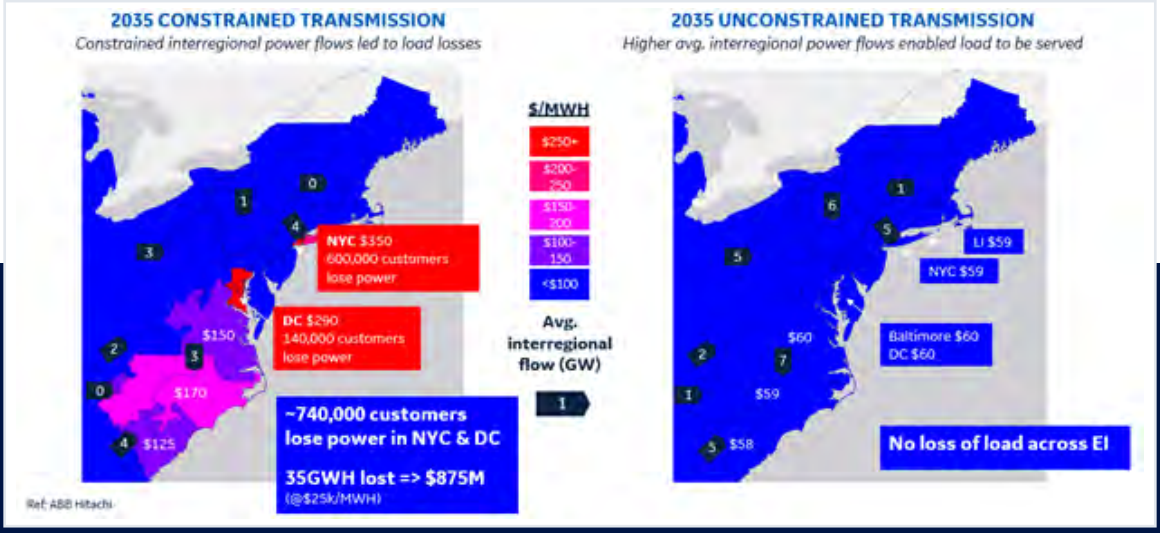


Figure 3 – Results of 2035 simulated heat wave: ~740,000 customers lost power in the constrained transmission case. These load losses were eliminated in the unconstrained transmission case via greater interregional power flows as shown.

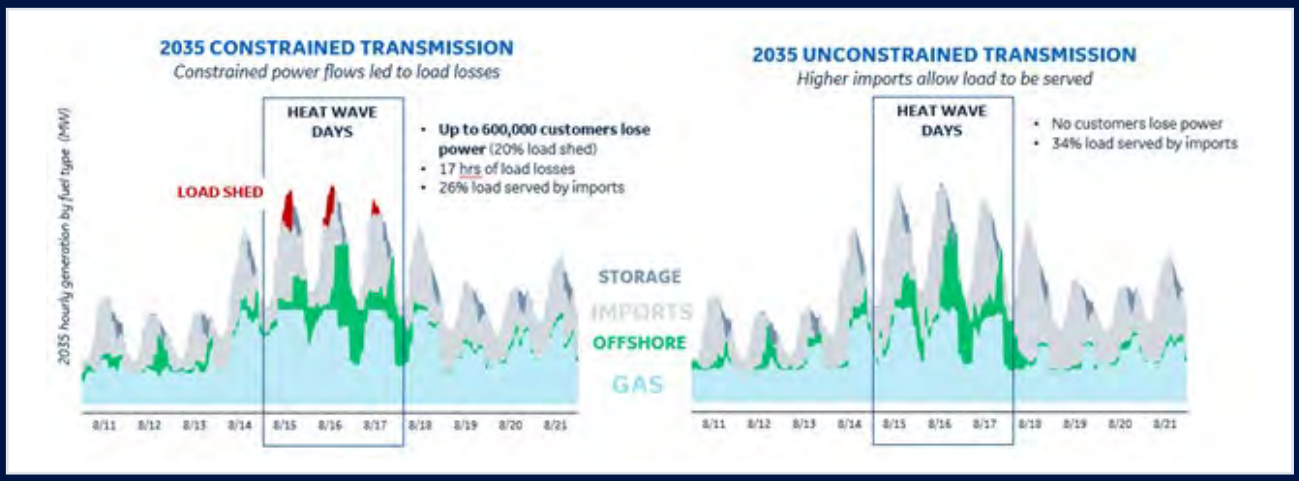


Figure 4 – Hourly New York City generation mix during the 2035 simulated heat wave: ~600,000 customers (20% of total load) lost power for 17 hours in the constrained transmission case. These load losses were eliminated in the unconstrained transmission case via greater interregional imports.

To examine the nature of the load shedding in more detail, Figure 4 shows the mix of generation that serve New York City during the simulated heat wave across both transmission cases. In both cases most of the load needs for these simulated days in August 2035 are served by natural gas, offshore wind, energy storage, and imports.

On August 15-17 of the simulated heat wave, load increases by 30% versus those days in a normal August. In the constrained case, as load increases, we start to see load shedding during peak hours since transmission constraints prevent additional generation to serve New York City with imports at ~26% of load. These load losses represent up to ~20% of load or approximately 600,000 customers without power for 17 hours. However, the unconstrained case shows there is zero load shedding and 34% of load is now served by imports given the increased amount of transmission.

GE then calculated the interregional transmission needed between each pool based on the results of the heat wave simulations as shown in Figure 5. The left of Figure 5 shows the average power flows between each pool for the constrained and unconstrained cases. The interregional transmission needed for each pool-to-pool connection would is calculated as the difference in the average power flows between the constrained and unconstrained cases. GE then assigned the transmission requirement to the pool importing the power as shown on the right side of Figure 5. The net result is 27GW of total interregional transmission requirement across the 9 pools shown with PJM bearing the largest requirement. Although this total figure may seem large at first, when looking at this requirement as a percentage total peak load, it is fairly small. For example, PJM's requirement of ~7GW represents ~4% of its 2035 peak load.

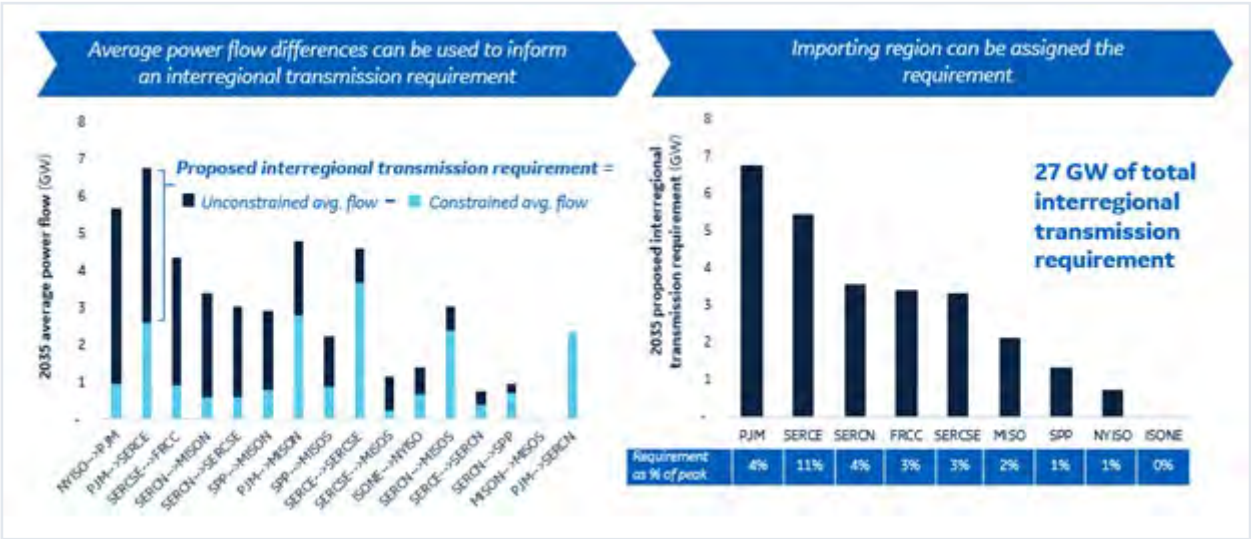


Figure 5 – Interregional transmission requirement given the average interregional power flow differences between the constrained and unconstrained heat wave simulations. The requirement is first defined based on the power flows between each pool and then the requirement is allocated to the pool importing the power.

2.1.3.3 Polar vortex analysis: Unconstraining transmission eliminates load losses

A similar analysis was performed in an example polar vortex case where electric system reliability is challenged not only by higher load, but also by generation outages, and fuel price spikes as outlined in Section 2.1.3.1. GE again simulated the EI under both a constrained and an unconstrained transmission system in order to inform the amount of incremental interregional transmission that is needed. The results of this simulation are shown in Figure 6.

Figure 6 shows average locational marginal prices (LMPs) across the EI during the 5 days of cold in February 2035 for both the constrained and unconstrained conditions. In the constrained transmission case, regional LMPs across the EI spike to greater than $500/MWH in the New York City, Washington, DC and Baltimore metropolitan areas whereas in the unconstrained transmission case, given the greater access to generation, prices do not spike as high. It is valuable to highlight here that the unconstrained simulations did not change transmission pathways into Canada. As a result, prices in the Northeast remain high in the unconstrained case though they are lower than the constrained case. The arrows connecting each pool in Figure 6 denotes the average power flow size and direction between pools. In the unconstrained case, shown on the right of Figure 6, these average power flows are significantly larger than in the constrained case. These larger average power flows enable more levelized prices.

More importantly, in the constrained case shown in Figure 6, given the increase in load combined with generation outages, fuel price hikes and the constraints in the transmission system to deliver more power, 35GWH of power is lost which is equivalent to ~2 million customers losing power across the largest Northeast metropolitan areas. Assuming $25k/MWh loss of load cost, this loss of load event equates to $875M. By unconstraining the transmission system, these load losses are eliminated.

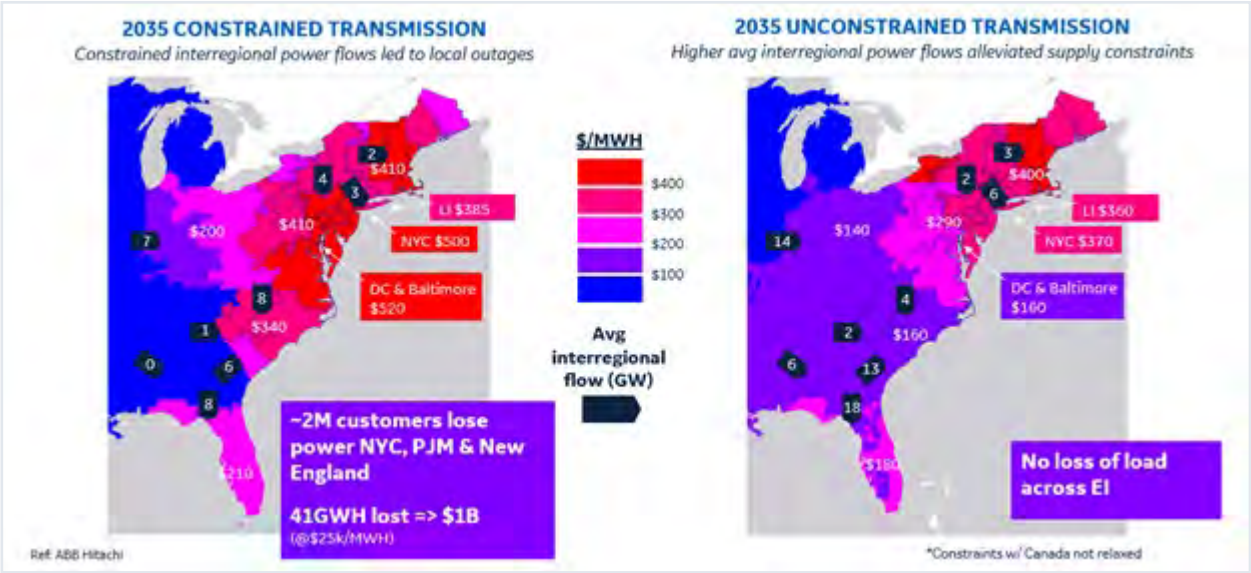


Figure 6 – Results of 2035 simulated polar vortex event: ~2 million customers lost power in the constrained transmission case. These load losses were eliminated in the unconstrained transmission case via greater interregional power flows as shown.

Greater transmission during a simulated polar vortex in February 2035, **prevented ~2 million customers losing power** across Boston, New York City, Baltimore and Washington, DC **saving $1B.**

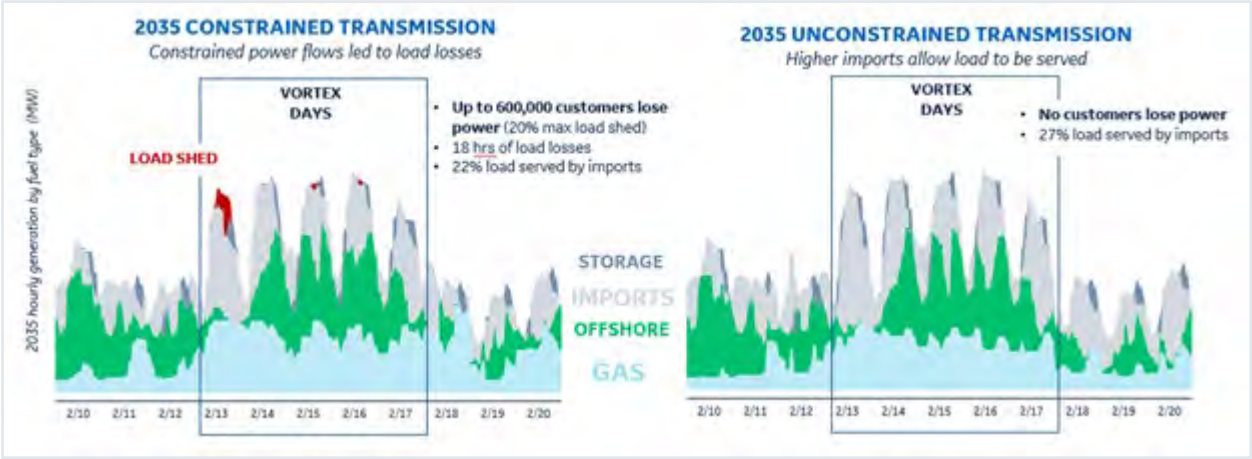


Figure 7 – Hourly New York City generation mix during the 2035 simulated polar vortex: ~2 million customers (20% of total load) lost power for 18 hours in the constrained transmission case. These load losses were eliminated in the unconstrained transmission case via greater interregional imports.

To examine the nature of the load shedding in more detail, Figure 7 shows the mix of generation that serve New York City during the simulated polar vortex across both transmission cases. In both cases most of the load needs for these simulated days in February 2035 are served by gas, offshore and imports.

On February 13-17 of the simulated polar vortex, ~15% of generation incurs forced outages while load increases by 40% versus those days in a normal February. In the constrained case, as load increases, load shedding occurs, especially during peak hours of February 13 since offshore wind generation is low that day and transmission constraints prevent additional generation from serving New York City, capping imports at ~22% of load. These load losses represent up to ~20% of load or approximately 600,000 customers without power for 18 hours. However, the unconstrained case results in zero load shedding, and 27% of load is now served by imports given greater transmission.

Greater transmission during a simulated heat wave in August 2035, **prevented ~740,000 customers losing power** across New York City and Washington, DC saving **$875M.**

Greater interregional transmission lowered US Eastern Interconnection capacity and ancillary service requirements, **saving $2B in 2035.**

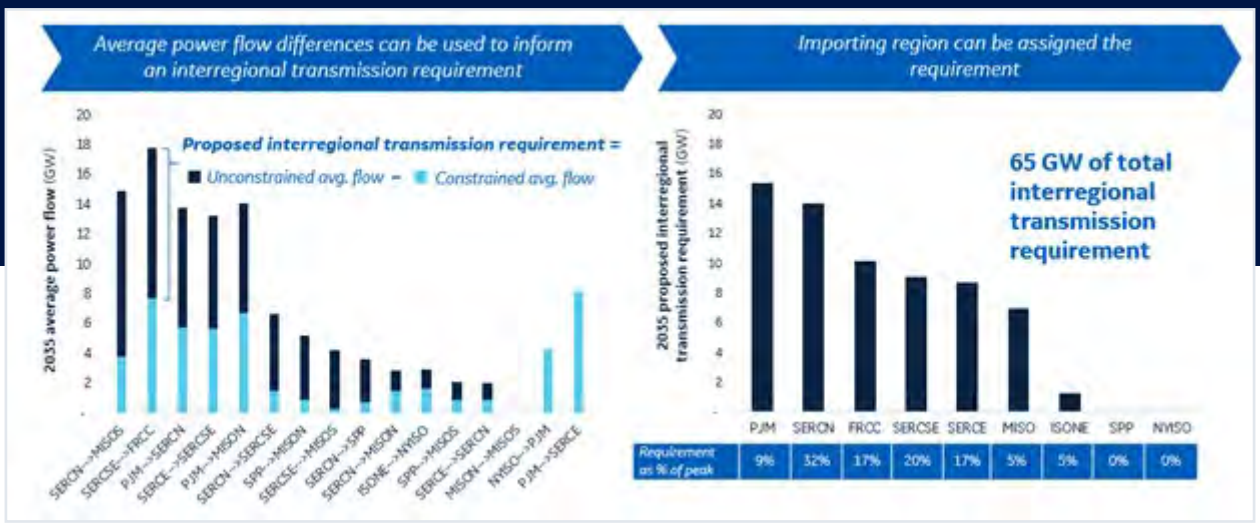


Figure 8 – Interregional transmission requirement given the average interregional power flow differences between the constrained and unconstrained polar vortex simulations. The requirement is first defined based on the power flows between each pool and then the requirement is allocated to the pool importing the power.

GE then calculated the amount of interregional transmission needed between each pool based on the results of the polar vortex simulations as shown in Figure 8. The left side of Figure 8 shows the average power flows between each pool for the constrained and unconstrained cases. The interregional transmission capacity for each pool-to-pool connection is calculated as the difference in the average power flows between the constrained and unconstrained cases. The incremental transmission is then assigned to the pool importing the power as shown on the right side of Figure 8. The net result is 65GW of total interregional transmission requirement across the 9 pools shown with PJM bearing the largest amount. While this total may seem large, when calculated as a percentage total peak load, this requirement is relatively small. For example, PJM's amount of ~15GW represents ~9% of its 2035 peak load. However, the transmission capacity needed for the Southeast are generally more significant as a percentage of load.

2.1.3.1 Calculating the total incremental interregional transmission needed for summer and winter resiliency

Now that the interregional incremental transmission requirement for each weather scenario has been determined, the total transmission needed to maintain for resilience can be calculated. As outlined in Equation 1, the total transmission needed for each pool-to-pool connection will be the maximum across both the summer and winter weather scenarios, as depicted in Figure 9.

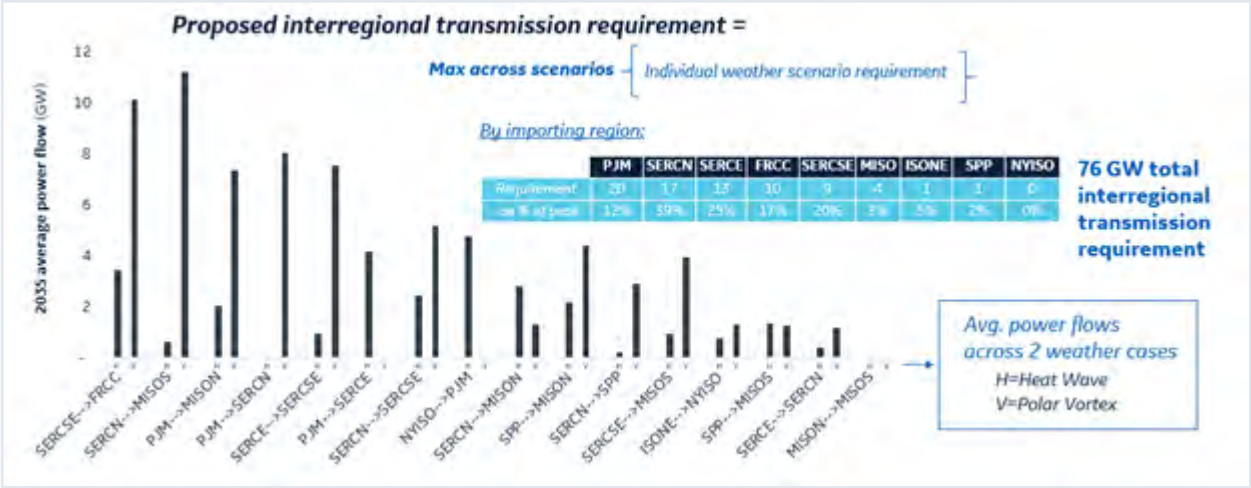
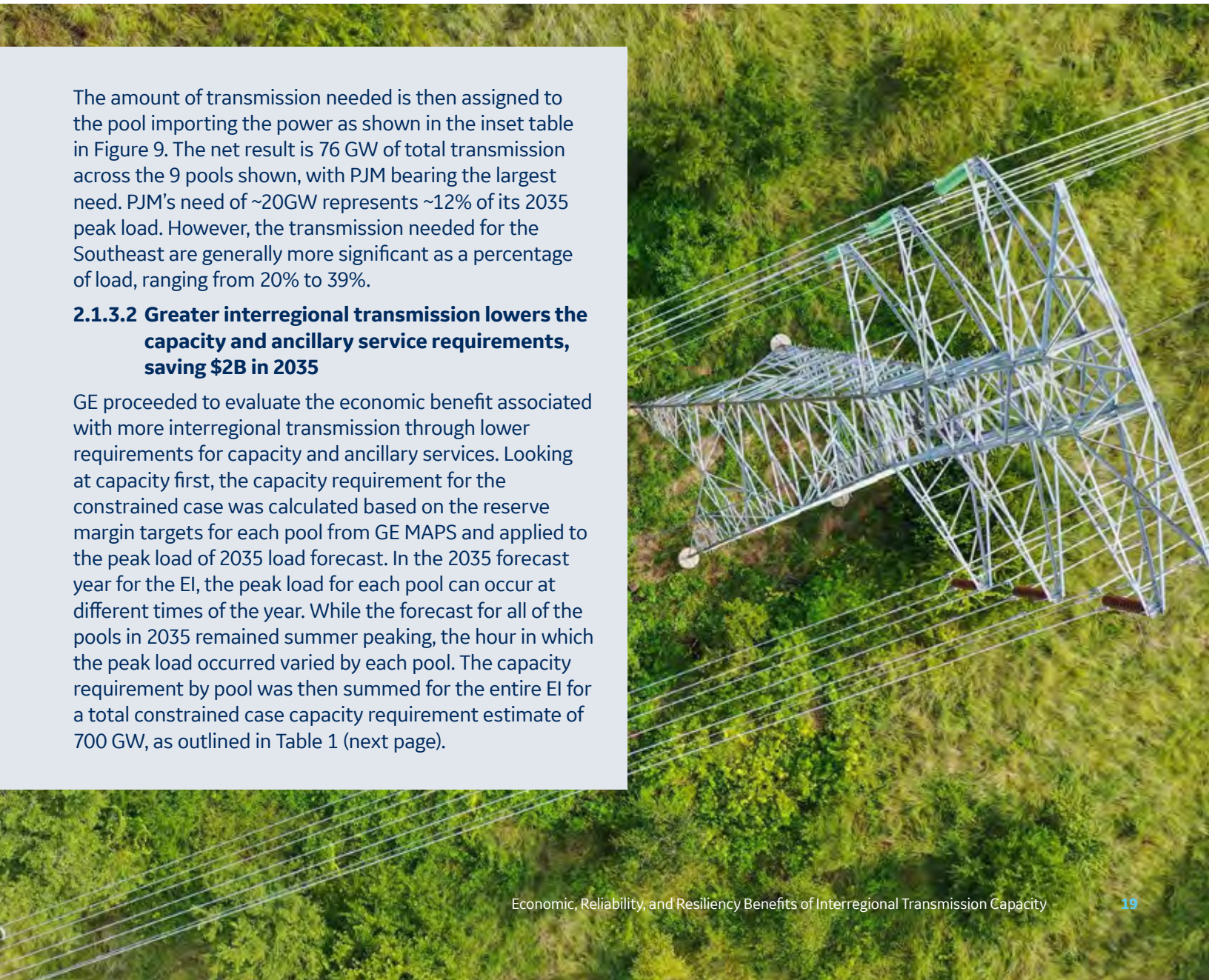


Figure 9 – The total resilience interregional transmission requirement will be determined by considering the average power flows across the weather scenarios. In our example, we determined each pool-to-pool requirement by selecting the max requirement from the two weather scenarios. Ideally, a broader range of weather scenarios would be considered.

The amount of transmission needed is then assigned to the pool importing the power as shown in the inset table in Figure 9. The net result is 76 GW of total transmission across the 9 pools shown, with PJM bearing the largest need. PJM's need of ~20GW represents ~12% of its 2035 peak load. However, the transmission needed for the Southeast are generally more significant as a percentage of load, ranging from 20% to 39%.

2.1.3.2 Greater interregional transmission lowers the capacity and ancillary service requirements, saving $2B in 2035

GE proceeded to evaluate the economic benefit associated with more interregional transmission through lower requirements for capacity and ancillary services. Looking at capacity first, the capacity requirement for the constrained case was calculated based on the reserve margin targets for each pool from GE MAPS and applied to the peak load of 2035 load forecast. In the 2035 forecast year for the EI, the peak load for each pool can occur at different times of the year. While the forecast for all of the pools in 2035 remained summer peaking, the hour in which the peak load occurred varied by each pool. The capacity requirement by pool was then summed for the entire EI for a total constrained case capacity requirement estimate of 700 GW, as outlined in Table 1 (next page).



Pool	Date/Time	Peak Hour Load	Target RM	Target Capacity
FRCC	9 Aug 17:00	59,509	20.0%	71,411
ISONE	3 Aug 15:00	25,797	13.6%	29,303
MISO North	3 Aug 15:00	97,075	16.8%	113,384
MISO South	6 Aug 15:00	32,758	16.8%	38,262
NYISO	16 Aug 15:00	31,868	18.9%	37,892
PJM	3 Aug 15:00	160,684	15.5%	185,590
SERCE	8 Aug 15:00	51,164	15.0%	58,839
SERCN	7 Aug 15:00	42,592	15.0%	48,980
SERCSE	8 Aug 15:00	44,679	15.0%	51,381
SPP	6 Aug 15:00	57,444	12.0%	64,337
Total EI		**603,571**	**15.9%**	**699,379**

Table 1: Constrained Case Peak Load by Pool and the corresponding total Capacity Target.

For the unconstrained case, the capacity requirement was calculated based on the EI peak load (summed load across all pools) which occurs on August 3, 2035, at 2:00 p.m. The reserve margin for the EI is estimated as the weighted average (by load) for each pool or 15.8%. In all likelihood, the planned reserve margin for the entire EI would likely be lower, based on the increased diversity of pooled resources represented by the EI, meaning the savings in capacity reported here is conservative and likely to be much higher. Assuming a weighted average of 15.8%, this results in a peak hour load of 586 GWs and a reserve capacity of 680 GW, or a capacity savings of 20 GW over the constrained case.

The capacity savings of 20 GW in the unconstrained case equates to a net capacity savings of $2 billion based on a net cone of $104/kw-year for a simple cycle gas turbine. The net cone is based on current GE MAPS assumptions and is consistent with prices published for capacity markets in the U.S. The results are presented in Figure 10.

New York City during blizzard conditions

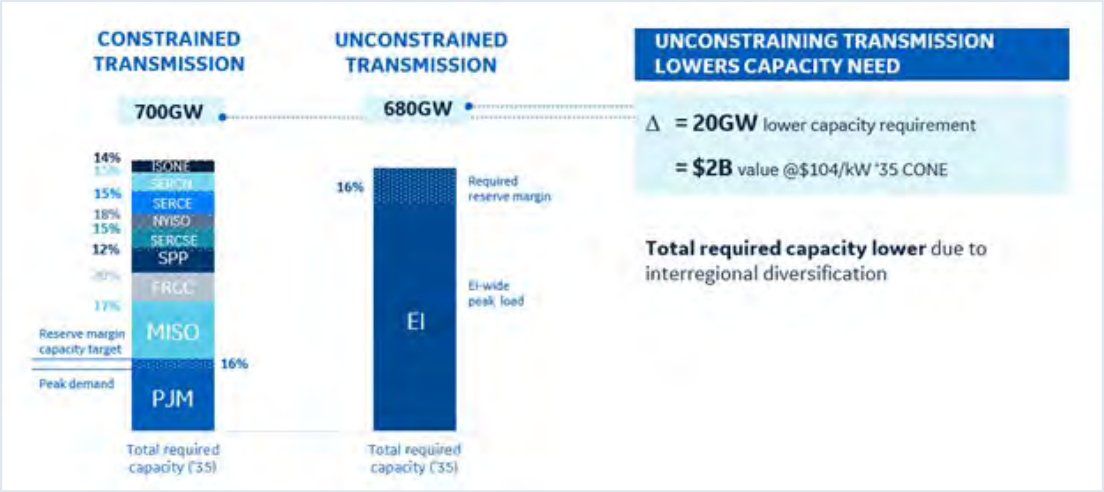


Figure 10 – The economic benefit of greater interregional transmission can be quantified by calculating the capacity requirement for the constrained and unconstrained cases. Given the interregional diversification of load that results from unconstraining transmission between pools, the total capacity requirement is 20GW less than in the unconstrained case resulting in an estimated $2B in savings.

To estimate the potential ancillary service savings in the unconstrained case, GE calculated the amount of generation capacity which was dispatched to serve peak load in both scenarios. This was calculated as the dispatched capacity for thermal and other dispatchable (or non-renewable generation) during the peak hour plus the renewable generation (wind and solar) and imports for the same hour.

This equates to 605 GW of available resources in the constrained case compared to 601 GW in the unconstrained case, for a reserves (ancillary services) savings of 4 GW (see Table 2, below).

Note that there was slightly higher renewable generation in the unconstrained case due to the elimination of curtailments relative to the constrained case of 1.2 GW during the peak hour. Furthermore, as expected, the unconstrained case benefits from an additional 9.4 GW of imports as compared to the constrained case.

Constrained Case	FRCC	ISONE	MISO North	MISO South	NYISO	PJM	SERCE	SERCN	SERCSE	SPP	Total
Committed Dispatchable Capacity	47,420.07	16,445.90	82,973.52	32,544.79	19,187.40	139,698.83	42,639.47	39,256.95	46,483.82	47,688.81	514,339.57
Renewable Generation	6,599.58	8,320.37	13,065.93	719.35	16,515.41	24,313.89	5,751.33	1,114.05	3,134.34	6,580.78	86,115.03
Imports	(307.65)	3,339.81	1,605.89	(1,601.36)	(2,386.09)	312.30	1,980.97	1,957.53	(3,724.63)	3,409.70	4,586.48
Total	53,712.00	28,106.08	97,645.34	31,662.79	33,316.73	64,325.02	50,371.76	42,328.54	45,893.53	57,679.29	605,041.09
Peak Hour Load	52,618.12	25,797.39	97,075.48	31,280.39	30,283.05	60,683.73	49,072.80	41,360.44	42,513.15	55,975.51	586,660.07
	2.1%	8.9%	0.6%	1.2%	10.0%	2.3%	2.6%	2.3%	8.0%	3.0%	3.1%
Unconstrained Case	**FRCC**	**ISONE**	**MISO North**	**MISO South**	**NYISO**	**PJM**	**SERCE**	**SERCN**	**SERCSE**	**SPP**	**Total**
Committed Dispatchable Capacity	47,555.67	18,253.10	82,611.72	35,132.79	20,027.26	136,675.04	35,399.31	37,431.85	45,182.74	41,844.13	500,113.62
Renewable Generation	6,599.58	8,320.37	13,065.93	719.35	17,674.73	24,313.89	5,751.33	1,114.05	3,134.34	6,580.78	87,274.35
Imports	(443.25)	2.88	1,993.10	(4,259.96)	(6,232.12)	3,388.94	8,994.75	3,782.63	(2,484.72)	9,240.68	13,982.94
Total	53,712.00	26,576.35	97,670.75	31,592.19	31,469.87	164,377.88	50,145.38	42,328.54	45,832.36	57,665.59	601,370.91
Peak Hour Load	52,618.12	25,514.50	97,075.48	31,280.39	29,925.61	160,683.73	49,072.80	41,360.44	42,513.15	55,975.51	586,019.73
	2.1%	4.2%	0.6%	1.0%	5.2%	2.3%	2.2%	2.3%	7.8%	3.0%	2.6%
Reserve Saving	(0.00)	1,529.73	(25.40)	70.60	1,846.86	(52.86)	226.38	(0.00)	61.17	13.70	3,670.18

Table 2: Operational Reserves savings between the Constrained and Unconstrained cases of 4 GW.

The benefit of lower spinning reserves is estimated to be $50 million/year based on average ancillary services prices for PJM in 2021 of $1.51/MWh.

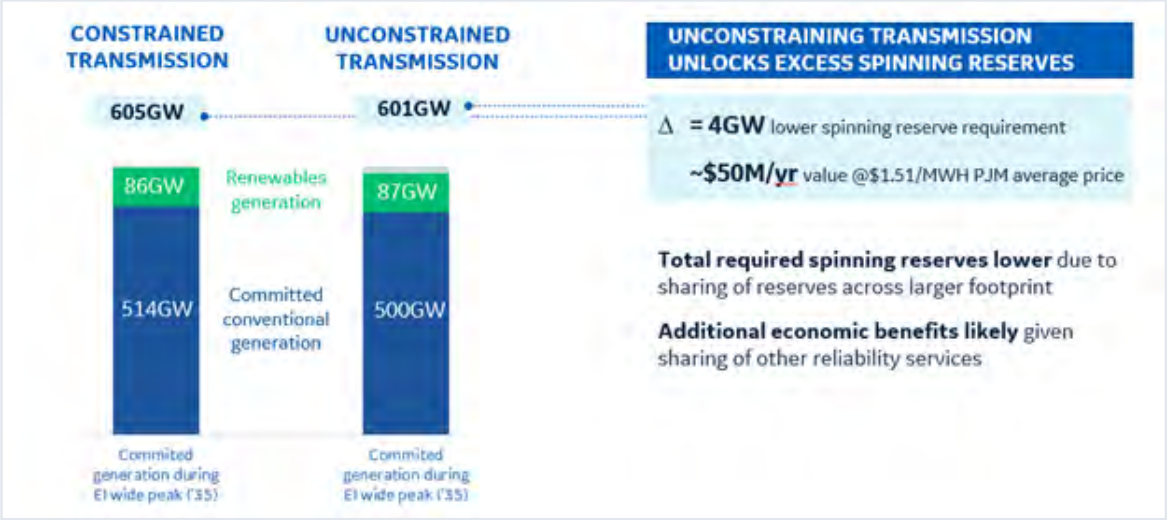


Figure 11 – Estimated economic benefit of greater interregional transmission from operational reserves savings of 4GW in the Eastern Interconnect between the constrained and unconstrained cases.

2.2 Benefits of incremental interregional transmission for increased affordability

2.2.1 Methodology

In order to quantify a potential minimum incremental interregional transmission capacity requirement for more affordable power usage, GE proposes simulating future system dispatch under the following two conditions:

1. *Condition 1:* **Constrained transmission.** This will allow the determination of the average power flow amounts between pools utilizing the existing/planned transmission system.
   Output metric: **Average constrained power flows** for each pool-to-pool interface.
2. *Condition 2:* **Unconstrained transmission.** For this simulation, GE suggests removing the MW limits associated with transmission flows. By removing the transmission line limits, we can determine the average power flows between pools in order to most economically serve load across the EI. This approach assumes that inter-regional transmission needs are coordinated with intra-regional needs.
   Output: **Average unconstrained power flows** for each pool-to-pool interface.

Utilizing simulations under both the constrained and unconstrained EI conditions allows an "affordability incremental interregional transmission requirement" to be calculated as follows:

Affordability incremental interregional transmission requirement

= Average unconstrained power flows - Average constrained power flows

Equation 2 - Formula for calculating the affordability incremental interregional transmission requirement.

This requirement would be calculated on a pool-to-pool basis across the United States. Costs for the required resources could be allocated to the pool importing the power.

Greater interregional transmission enabled **access to lower cost generation saving $3B/year in 2035** increasing to $4B in 2040.

2.2.2 Example affordability analysis: Greater interregional transmission enables access to lower cost generation saving $3B/year in 2035

Another benefit of increased interregional transmission is greater access to lower cost wholesale power sources. To estimate this, GE again simulated a constrained and unconstrained transmission system and simulated hourly dispatch across the EI using GE MAPS. Please refer to Section 4 for a summary of the assumptions used in the GE simulation performed here.

Figure 12 shows average locational marginal prices (LMPs) across the EI in 2035 for both the constrained and unconstrained conditions. By comparing the cases, there is significantly less price variation in the unconstrained versus constrained case. The arrows connecting each pool in Figure 12 denote the average power flow size and direction between pools. In the unconstrained case, these average power flows were significantly larger than in the constrained case. These larger average power flows enabled the resultant price smoothing. By allowing cheaper generators to serve more load, transmission enables $3-4 billion in production cost savings in the unconstrained case versus the constrained case.

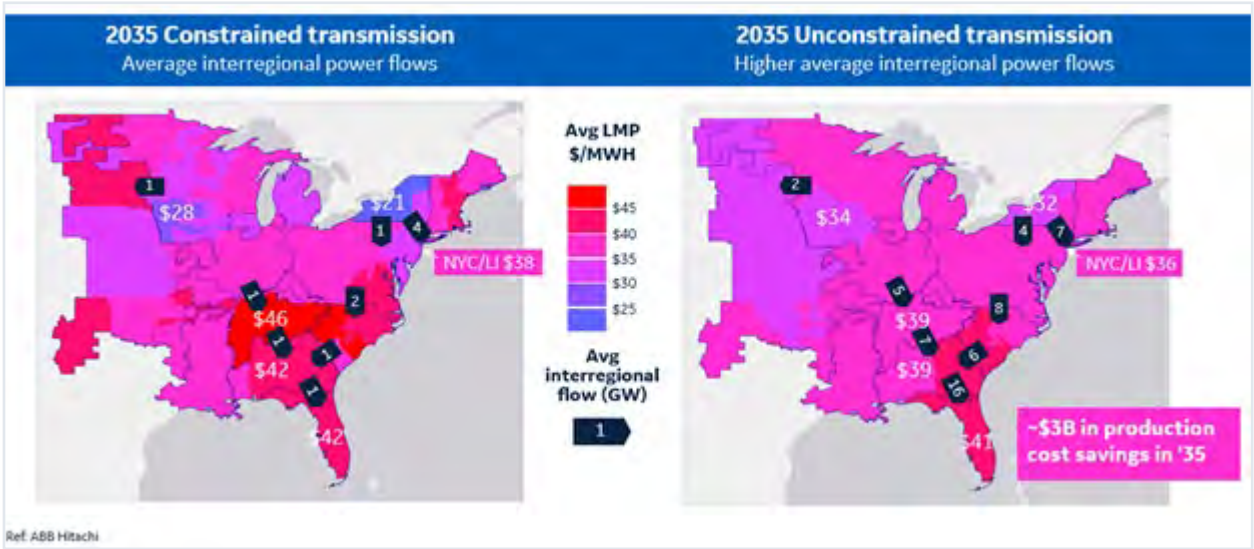


Figure 12 - Results of GE simulations to assess the affordability incremental interregional transmission requirement.

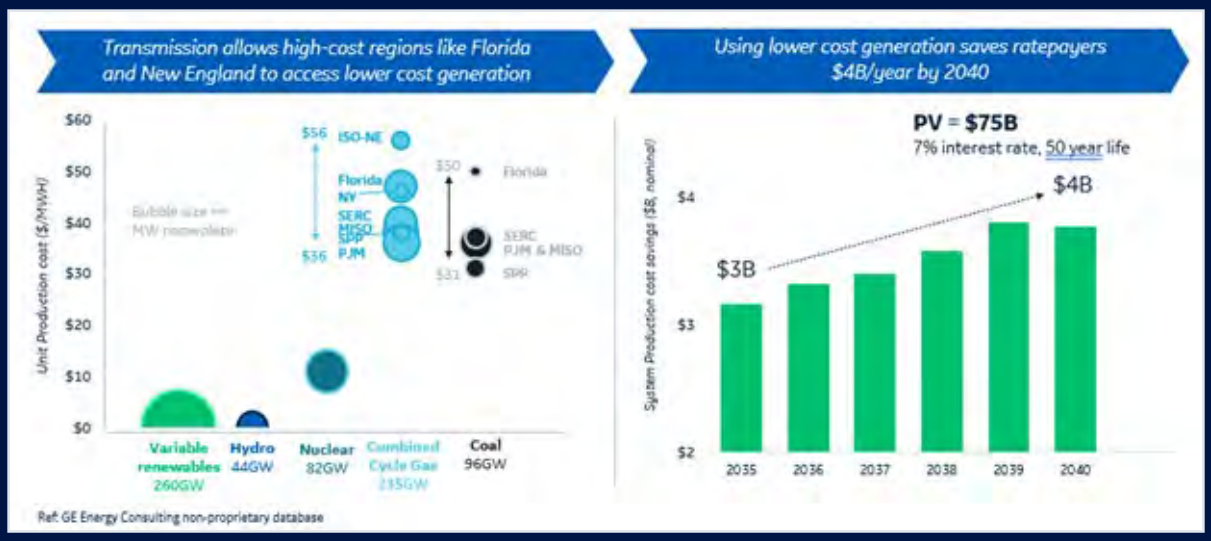


Figure 13 - Production costs vary by fuel type and location. Unconstraining transmission allows regions with high generation costs access to lower cost resources. The result is annual production cost savings of $4B by 2040.

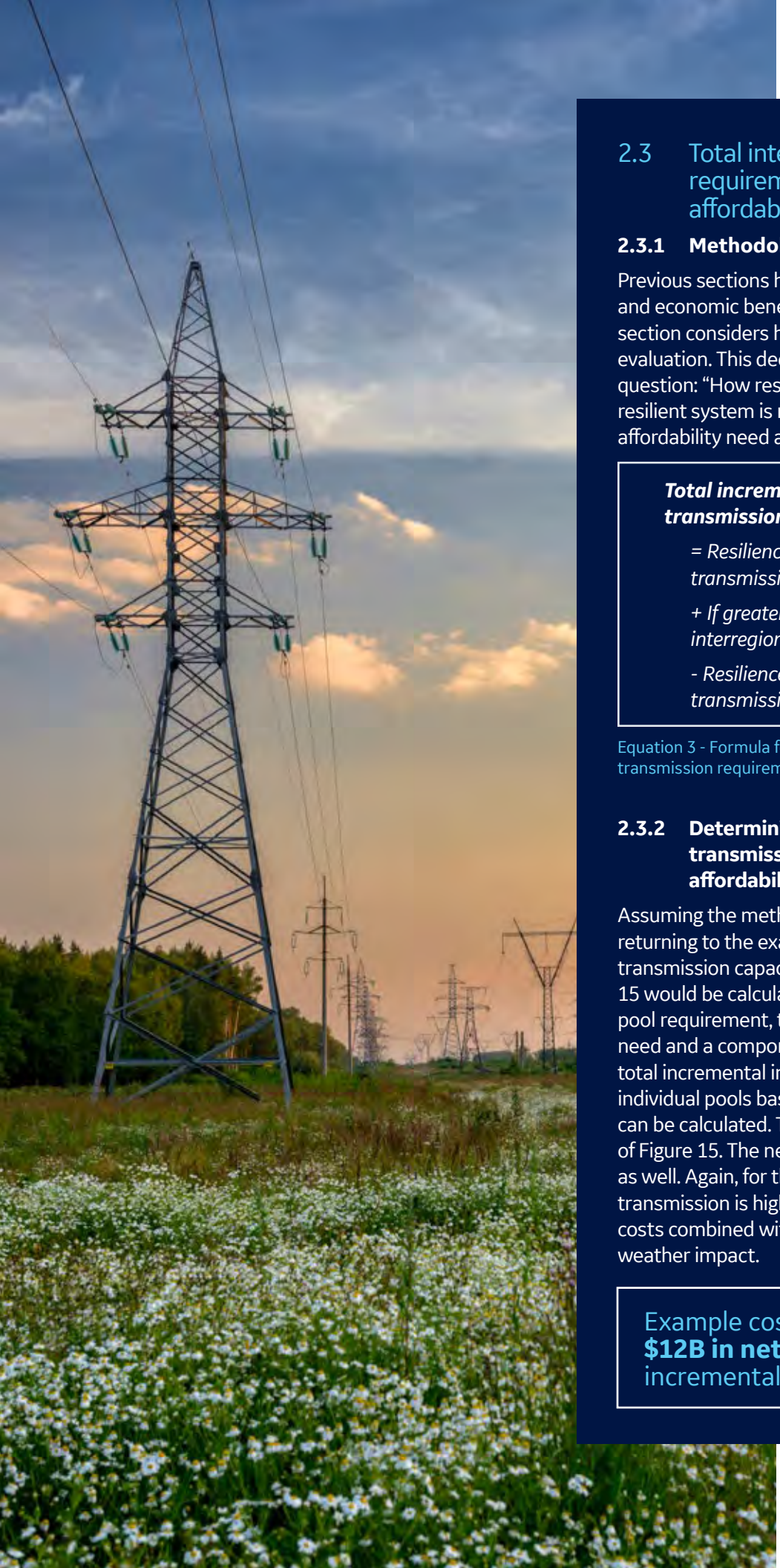
The $3-4 billion in production cost savings enabled by unconstrained transmission in 2035 is due to the locational variation in generation cost across the EI combined with the higher average power flows enabled by the transmission system. As Figure 13 shows, generation production costs vary by fuel type and location. The highest costs of generation were generally in New England and the Southeast where the costs of delivered gas and coal are higher than other parts of the EI. By unconstraining the EI transmission system, regions with high generation costs could access a wide range of lower cost generation from other parts of the EI.

As Figure 13 shows, such savings from access to lower cost generation increases from $3 billion in 2035 to $4 billion by 2040. Such an increase in savings is driven by a sharp increase in load over the same time period given factors like electrification. Assuming a 50-year life for transmission assets, the annual savings translates into a $75 billion present value.

Figure 14 - Proposed incremental interregional transmission requirement can be calculated on a pool-to-pool basis where the requirement can be assigned and cost-allocated to the pool importing the power.

The left side of Figure 14 illustrates the difference in capacity between the constrained and unconstrained average power flow by power pool. Please note that the average power flow levels shown in the graph here correspond to the same average power flows represented by the arrows in Figure 12. Given that the Southeast has some of the highest generation costs, it is not surprising that it has the highest need for interregional transmission.

The amount of incremental interregional transmission needed is assigned to individual pools based on the pool importing the power. The results are shown on the right side of Figure 14. It also shows the need on a % of peak load basis as well. Again, for the Southeast, the need is highest given its relatively high generation costs.



2.3 Total interregional transmission requirement across resilience & affordability

2.3.1 Methodology

Previous sections have evaluated separately the resiliency and economic benefits of interregional transmission. This section considers how to incorporate both benefits in an evaluation. This decision essentially boils down into the question: "How resilient should the system to be?" If a fully resilient system is needed, the greater of the resilience and affordability need as outlined by Equation 3 should be used.

Total incremental interregional transmission requirement

= Resilience incremental interregional transmission requirement

+ If greater than zero [Affordability incremental interregional transmission requirement

- Resilience incremental interregional transmission requirement]

Equation 3 - Formula for calculating the total incremental interregional transmission requirement across resilience & affordability.

2.3.2 Determining the total incremental interregional transmission need for resiliency and affordability results in 87GW of transmission

Assuming the methodology outlined in Equation 2 is used, returning to the example analysis, each of the pool-to-pool transmission capacity requirements as shown in Figure 15 would be calculated. This shows that for each pool-to-pool requirement, there is a component from the resiliency need and a component from the affordability need. The total incremental interregional transmission needed for individual pools based on the pool importing the power can be calculated. The results are shown on the right side of Figure 15. The need on a % of peak load basis is shown as well. Again, for the Southeast, the need for interregional transmission is highest given its relatively high generation costs combined with the GE assumptions around extreme weather impact.

Example cost benefit analysis shows **$12B in net benefits** from 87GW of incremental interregional transmission.

Figure 15 - Proposed incremental interregional transmission need can be calculated on a pool-to-pool basis where the requirement can be assigned and cost-allocated to the pool importing the power.

2.3.3 Example cost benefit analysis shows $12 billion in net benefits

Now that the total incremental interregional transmission need for each region has been determined, the total net benefits by summarizing the total costs and total benefits can be calculated. For the example analysis presented, the costs and benefits are summarized in Figure 16.

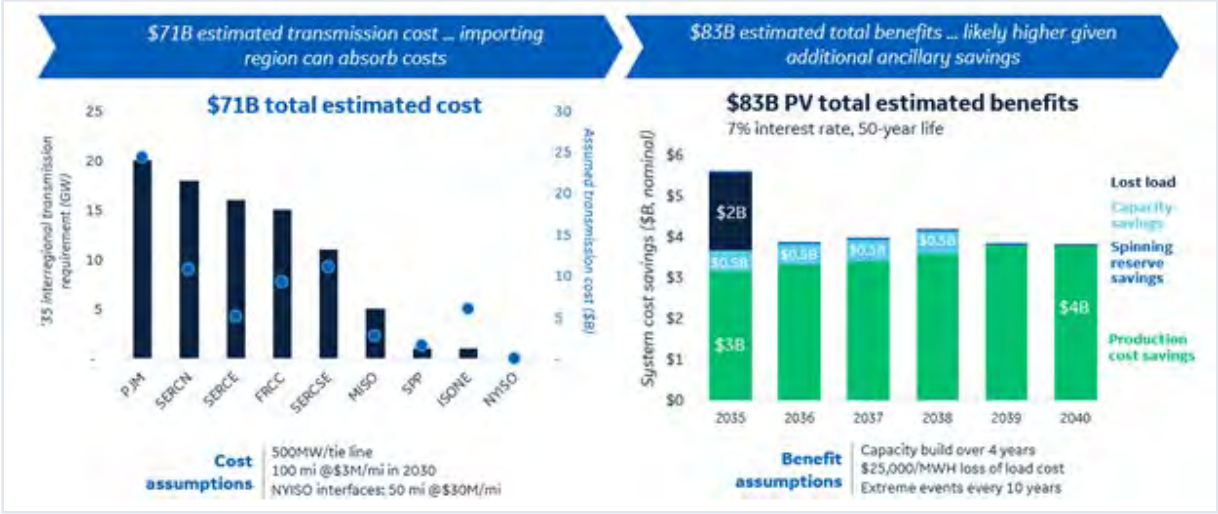


Figure 16 – Cost-benefit analysis showing $12B in net benefits given $71B in total estimated transmission costs and $83B in total estimated benefits.

The left side of Figure 16 summarizes a $71 billion cost estimate for the 87GW of incremental interregional transmission determined in Section 2.5. This estimate is based on some broad assumptions for the purpose of illustrating this methodology. The cost assumptions are outlined on the left side of Figure 16.

The right side of Figure 16, summarizes $83 billion in total benefits across the four areas of benefit discussed throughout this example analysis. The majority of the benefits come from the annual production cost savings given the more cost-efficient use of generation, but significant benefits also stem from loss of load, capacity cost, and spinning reserve savings.

The net result of this example cost-benefit analysis is $12 billion in net benefits. This net benefit can potentially be used to invest in intra-regional transmission to enable the benefits outlined here. As noted earlier, this estimate of benefits is likely conservative and could be much higher.

However, to realize the full benefits of expanded transmission, even of this conservative estimate, one would have to coordinate both intra-regional and inter-regional planning as well as operational norms to increase imports and exports between regions.

2.4 Benefits of interregional transmission for increased grid stability

The proposed methodology was focused on the adequacy part of grid resiliency: does the system have enough generation to meet load given extreme weather events? However, as the grid is evolving to include greater diversity of technologies such as synchronous machines, inverter-based resources, transmission assets, distributed generation, and load resources, unwanted equipment interactions often referred to as "stability risks" are increasingly becoming important in ensuring future reliability of the electric power grid.

While a system can be adequate in terms of having enough generation, it can still be unstable given the mix of resources. In the face of extreme weather, for example, a lightning strike can result in unstable fluctuations in voltage or frequency leading to unwanted behavior or tripping of generation equipment. Such trips can have cascading effects as well. NERC regularly summarizes examples of such events.

The analysis so far assumes interregional AC transmission interconnection only. However, there may be reasons to consider alternate reinforcements like DC interconnections to ensure system stability.

For this analysis, GE utilized the following screening methodology:

Test: Is the grid stable assuming the incremental interregional requirement is AC? A stable system would have to pass each of the following criteria:

Grid stability is also increasingly a risk during **extreme weather events. Alternate transmission technologies** (e.g. DC vs AC connections) should be considered to maintain grid stability under extreme weather pressure **with high inverter-based resource penetrations.**

- **Weak grid?** Does grid voltage remain stable after grid disturbances (e.g., lightning strike, generator trip, equipment switching) or does voltage collapse resulting in cascading outages? Short circuit ratio screening methodology is an industry standard test of grid strength. If the short circuit ratios above are low (e.g., <3), the grid is too weak to maintain stable voltage and reinforcements are required. AC interregional transmission may help improve grid strength, but if improvements are not sufficient, additional reinforcements like DC technology or condensers may be necessary.
- **Stable frequency?** Does frequency recover after a large grid disturbance (e.g., lightning strike, generator trip) or does frequency collapse resulting in cascading outages? Screening for this risk involves assessing the amount of headroom (i.e., ability to increase power output) generators have in order to respond and recover from a loss of a large power station. If headroom is low in one region, and transmission constraints limit access to other regions, then interregional transmission may help open up the opportunity to share headroom across a wider footprint to support stable frequency.
- **Small signal instabilities?** Are there unwanted resonances that could result in generator outages? Screening for this risk involves identifying low order grid resonances caused by areas of long undersea cable or series compensated transmission corridors. This screening may be done through investigation of system topology, frequency-impedance scans and grid EMT (electromagnetic transients) modeling to uncover risks of unwanted power swings and tripping of areas of the grid. This methodology may also be used to determine the risks / benefits of DC vs. AC interregional transmission.

If all pass: The AC requirement is sufficient for stability risks.

If any fail: There could be stability risks that interregional reinforcements could help mitigate. Deeper analysis is needed to determine systemic risk and mitigation methodology.

2.4.1 Example analysis: Even with significant AC interregional reinforcement, Eastern seaboard grid remains weak--interregional DC may be preferred for resiliency

For this example, GE calculated the short circuit current ratio (SCR) for three pockets of ISO-NE, NYISO, and PJM where significant levels of offshore wind are projected.

Short circuit current ratio (SCR) is an industry-standard metric for assessing the strength of the grid's voltage. In general, an SCR above 10 is considered strong and a transmission voltage of 230kV, for example, will remain within acceptable limits despite grid disturbances such as lightening or unit trips. An SCR below 3 is considered weak. In a weak grid, a transmission voltage of 230kV, for example, may fluctuate outside of acceptable limits during grid disturbances such as extreme weather, resulting in generation tripping offline to avoid damage.

Figure 17 summarizes the results of our SCR analysis for the constrained and unconstrained transmission cases. In the constrained case, given the assumed penetration of offshore wind into ISO-NE, NYISO, and PJM, the SCR is weak across all three RTO pockets. In addition, the SCR at the offshore wind plant locations are all weak as well. The net result is that the grid in the constrained case is too weak to maintain a stable voltage during both normal operations and after extreme weather disturbances.

For the unconstrained case, it was assumed the needed amounts of incremental interregional AC transmission calculated in Section 2.5 would connect these three RTO pockets. GE then recalculated the SCR. Figure 17, shows how in the unconstrained case, the increased AC interregional transmission improved the SCR for each of the three RTO pockets versus the constrained case. However, while there was an improvement in SCR from 2 to 4 or 5, depending on the location, it still may not be enough to result in a stable grid. In addition, the SCR at the offshore wind plant locations all remained weak as well due to their distant electrical proximity and the high concentration of IBR in one area. The net result is that, while interregional transmission marginally improved the grid strength across regions, the grid in the unconstrained case is likely still too weak to be stable during both normal operations and extreme weather disturbances.

In such a circumstance, if PJM, ISO-NE, and NYISO were to incorporate an interregional transmission requirement assuming AC interregional transmission alone, certain benefits could be lost that would be provided by alternative transmission technologies such as DC ties. The control instabilities and voltage fluctuations associated with weak AC grids could be mitigated with properly coordinated VSC-HVDC technology and offshore wind plants. By building out DC versus AC interregional transmission, the grid strength risks identified here could be mitigated.

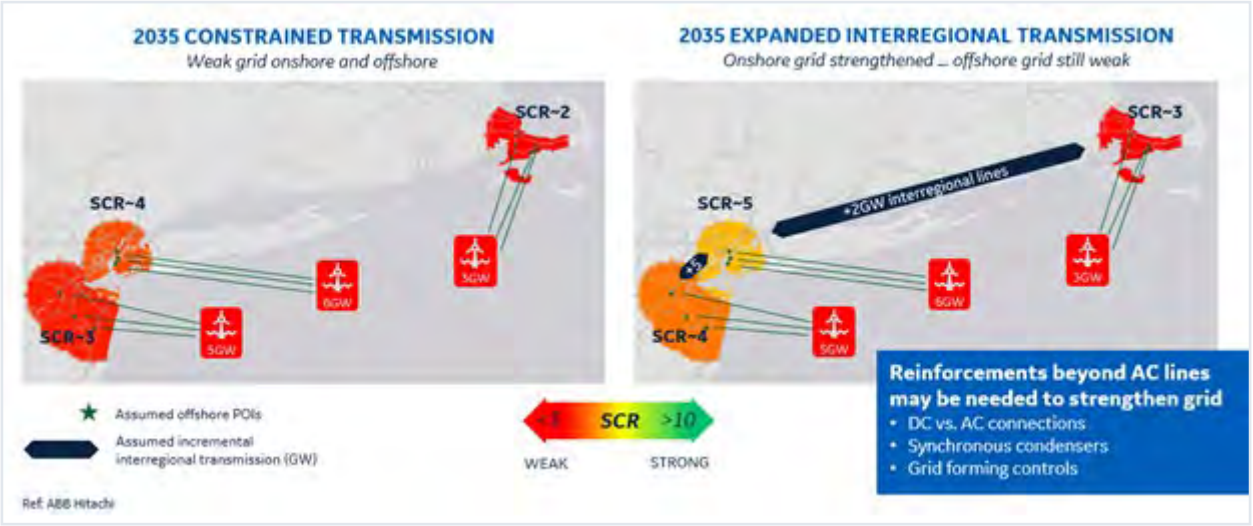
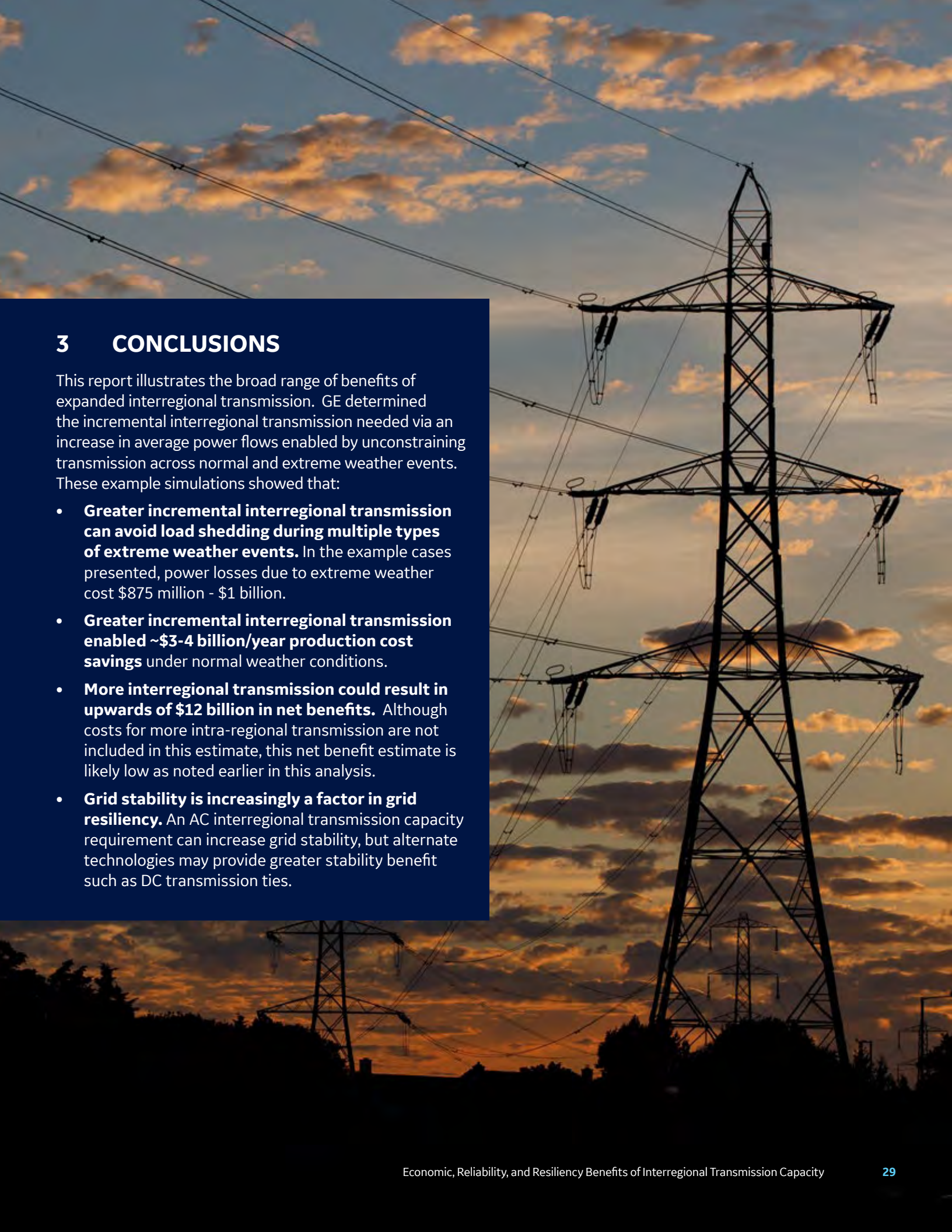


Figure 17 – Short circuit current (SCR) analysis for pockets of ISO-NE, NYISO, and PJM where the mix of resources may result in grid weakness. AC interregional transmission helps strengthen the grid but additional interregional reinforcements like DC transmission could provide greater stability benefit.



3 CONCLUSIONS

This report illustrates the broad range of benefits of expanded interregional transmission. GE determined the incremental interregional transmission needed via an increase in average power flows enabled by unconstraining transmission across normal and extreme weather events. These example simulations showed that:

- **Greater incremental interregional transmission can avoid load shedding during multiple types of extreme weather events.** In the example cases presented, power losses due to extreme weather cost $875 million - $1 billion.
- **Greater incremental interregional transmission enabled ~$3-4 billion/year production cost savings** under normal weather conditions.
- **More interregional transmission could result in upwards of $12 billion in net benefits.** Although costs for more intra-regional transmission are not included in this estimate, this net benefit estimate is likely low as noted earlier in this analysis.
- **Grid stability is increasingly a factor in grid resiliency.** An AC interregional transmission capacity requirement can increase grid stability, but alternate technologies may provide greater stability benefit such as DC transmission ties.

4 APPENDIX

4.1 Study assumptions

GE Energy Consulting continuously updates its North American MAPS databases, including the Eastern Interconnect database used for this study. Primary updates like load forecasts typically are incorporated in the late spring or early summer after the relevant Independent System Operators publish their updated forecasts. Similarly, GE Energy Consulting employs a separate production cost model for the natural gas price forecasts for North America, which is primarily updated in the summer.

Once the study for NRDC started in April, GE froze a version of the MAPS database to maintain consistent results throughout the study. As such, the MAPS database used for this analysis was limited to the primary assumptions implemented for the previous year 2021, including load forecasts and fuel forecasts, meaning the sharp increase in natural gas and coal prices were not captured in this analysis. This limitation was communicated to the NRDC team at the beginning of the study. Incorporating more recent load and fuel price forecasts would not have had a significant impact on the primary results of this study, and if anything, would further increase the benefits of interregional transmission.

4.1.1 Load assumptions

Load assumptions for this study were based on updates completed in 2021. GE Energy Consulting utilizes detailed load forecasts published, where available, by each independent system operator, including, for example, the ISO New England's Forecast Report of Capacity, Energy, Loads and Transmission (CELT Report) and NYISO's Gold Book. For those regions without published forecasts, GE Energy Consulting uses regression analysis with US GDP forecasts to create annual peak and energy forecasts.

It should be noted that the load forecasts developed in 2021, including those published by ISO New England and NYISO, did not include projected future changes to loads like electrification of space heating and more extensive adoption of electric vehicles. These changes in load forecasts were evident in updates recently published in 2022. As a result, most of the load assumptions for the year 2035, which was a focal point of this study, did not include changes from a summer to winter peaking system as might have been expected. It is likely that if this study had begun later this year, the new load forecast would have exemplified more of this shift in electrification and would further increased the financial benefits of interregional transmission in the polar vortex case.

Figure 18 below highlights the load assumptions graphically for the individual pools of the Eastern Interconnect. The load growth continues at roughly 1% per annum.

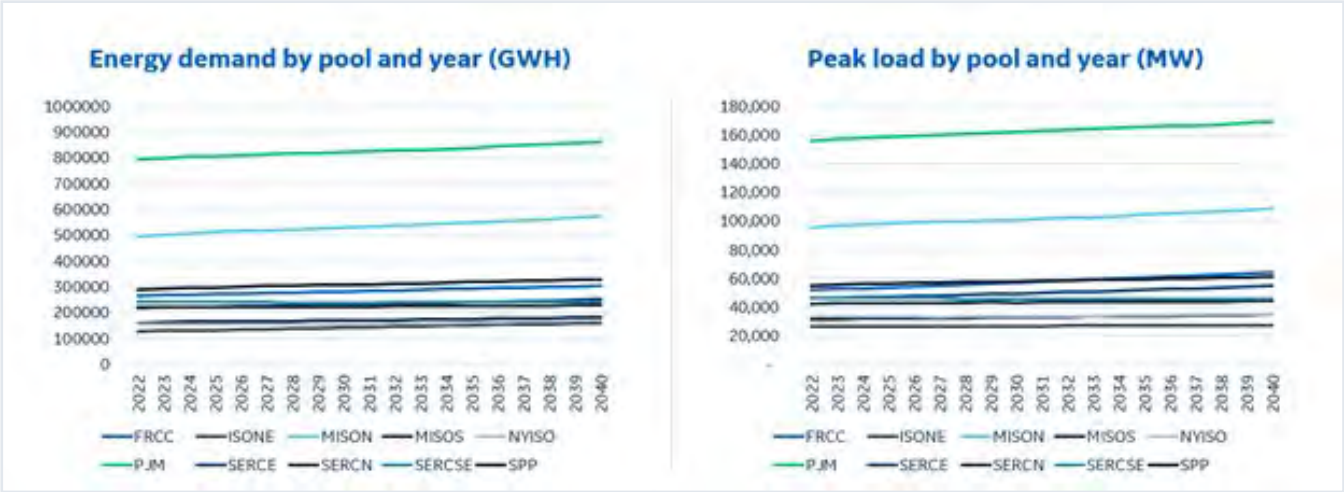


Figure 18 GE load growth assumption across pools ~1%/year … steeper growth 2040+. GE Energy Consulting load assumptions based on RTO-issued forecasts.

4.1.2 Generation assumptions

Generation capacity depends on timely updates to generator additions (expansion or new unit builds) and retirements. Typically, utilities will announce the expected retirements of their large base load generators several years in advance, including large coal fired generators. GE regularly incorporates these announcements as part of the planned capacity additions and retirements.

In addition, GE evaluates state policies such renewable energy requirements into generation capacity forecasts. To highlight this (see Figure 19 below), GE has forecasted the addition of 28 GWs of offshore wind generation to the Eastern Interconnect between 2023 and 2035 despite the fact that this is a nascent technology in the U.S. with less than 100 MW of installed operating capacity as of this writing. This is similarly true for our forecasts of solar generation, increasing nearly 150% between 2023 and 2040 and coal capacity declining by 50% over the same horizon.

GE expects that these capacity forecasts will change even over the next year. A recent publication by DOE in May 2022, expects 40 GW of offshore wind is in active development, an increase of 13.5% over its 2021 report. While GE regularly updates its wind and solar forecasts to match the best data available and recognizes the rapidly shifting environment to decarbonize the grid, it is reasonable to expect continued operation of some of the thermal fleet.

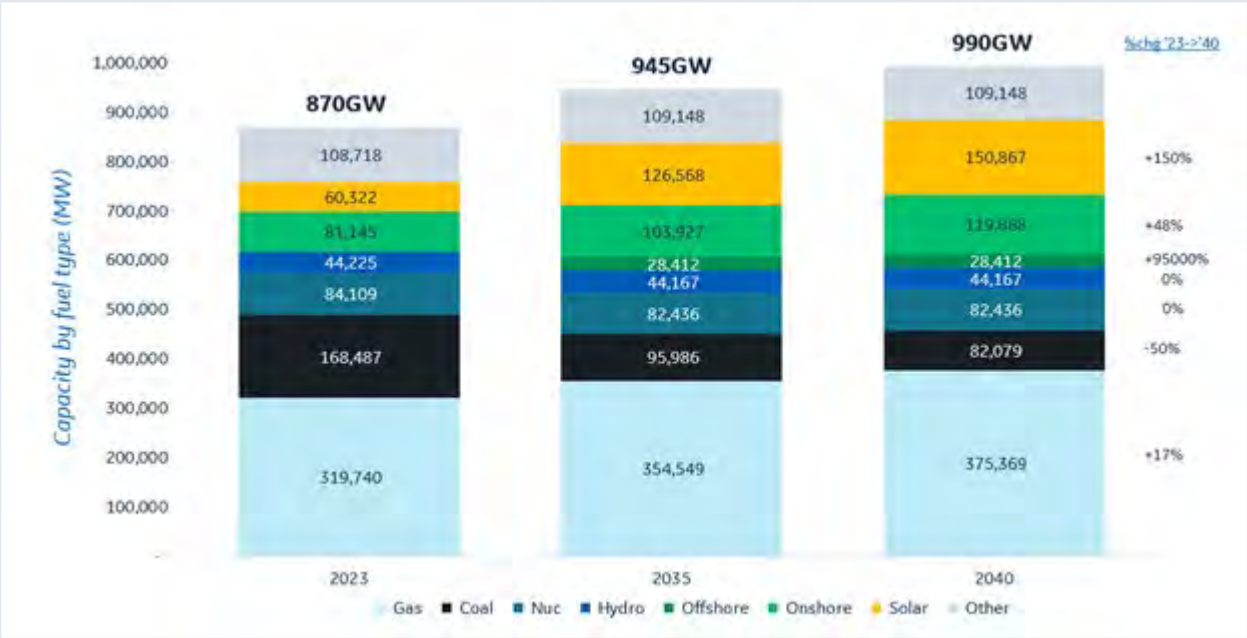


Figure 19: GE Generation capacity forecast assumptions summarized for years 2023, 2035 and 2040. As expected, the fastest capacity additions are wind and solar renewables while coal generation declines over the same horizon.

4.1.3 Fuel price assumptions

GE Energy Consulting uses a fundamentals model to forecast natural gas prices in North America. As noted previously, those updated natural gas forecasts for 2022 were not available when GE started this study and froze all assumptions.

While recent price spikes in both electricity, coal and natural gas prices could have a significant impact on this analysis, current real long-range price forecasts predict natural gas prices will fall to below $4.00/mmBTU (in 2021 $) in 2030 and remain there, with some minor deviations, until 2050. While the near term price of natural gas is significantly higher in 2022 due to a number of factors, as noted earlier, the longer term prices have increased only marginally. Also, higher natural gas prices will only increase the benefits of interregional transmission.

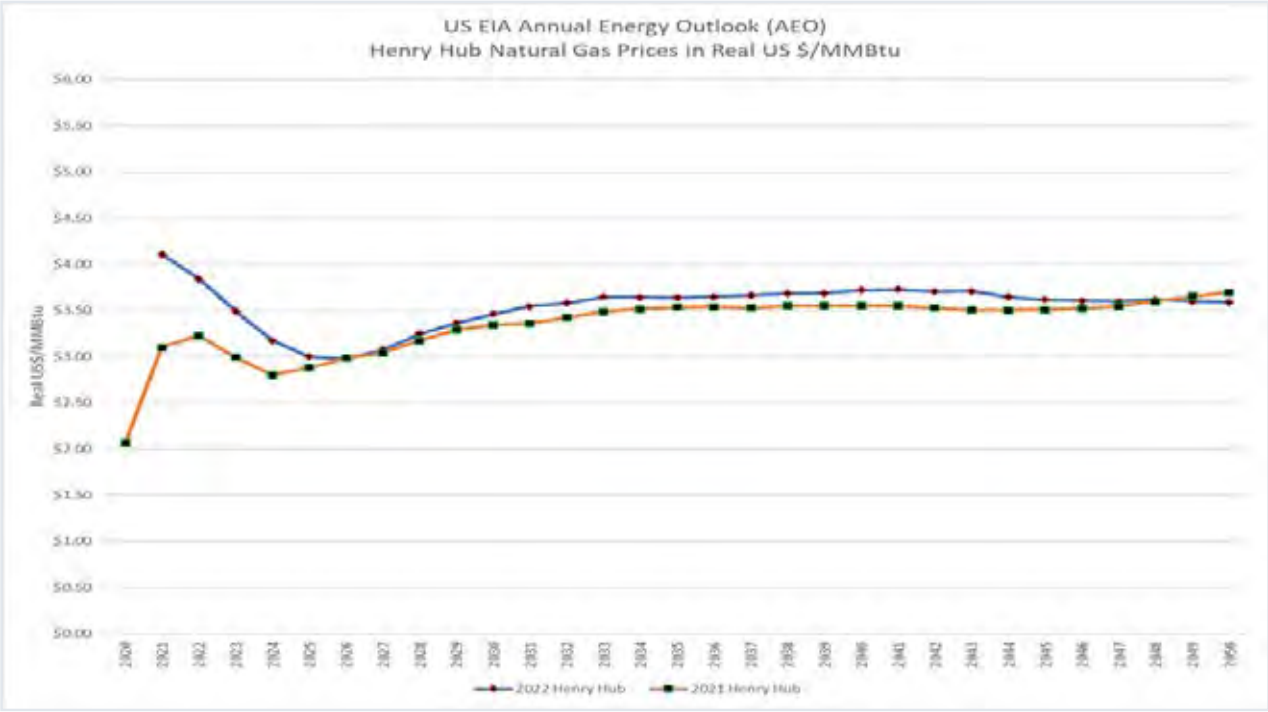


Figure 20: Henry Hub Natural Gas price comparison EIA AEO 2022 vs 2021forecasts (real US$/MMBtu).

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GEA35221 (10/2022)