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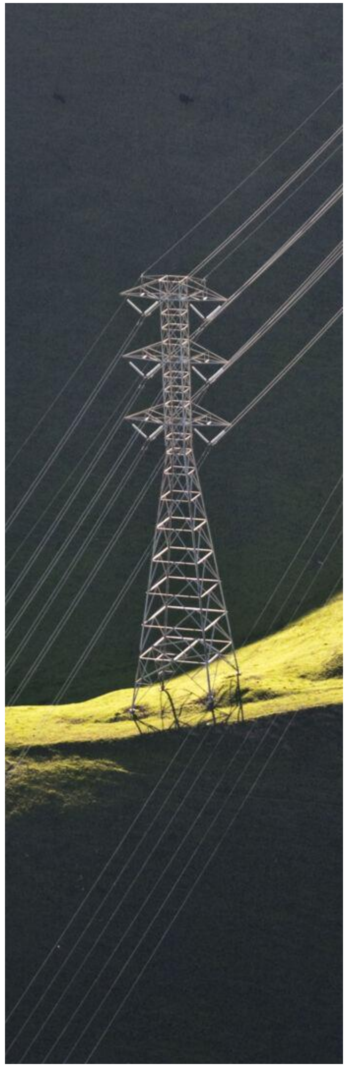
CERA Consulting

Powering Growth and Affordability: The Role of Transmission in Economic and National Security

Report by S&P Global Energy
August 2026

CERA Consulting is the consulting arm of S&P Global Energy



S&P Global Energy Study Acknowledgements

This report represents the independent analysis and views of S&P Global Energy. The study was supported by Electricity Customer Alliance and National Grid. S&P Global Energy is exclusively responsible for all analyses, content and conclusions of the study, except for the national security and defense aspect, for which Converge Strategies is responsible. The study makes no policy recommendations

This study offers an independent and objective assessment of the transmission investment needed to support load growth and broader national priorities. As demand from key strategic sectors continues to shift rapidly and dynamically, alongside evolving economic and security objectives, the study helps identify the scale, location, and type of transmission investment required. It also evaluates how regional and interregional transmission buildout can support future load growth, improve customer affordability, and prevent or mitigate long-duration power disruptions. The analysis and metrics developed during the course of this study represent the independent analysis and views of S&P Global Energy

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Source: S&P Global Energy

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Key Findings

1	Commercial and industrial expansion (including advanced manufacturing, data centers, and domestic industrial growth), along with electrification, drive the bulk of US electricity demand growth through the mid 2030s, adding 374 TWh of energy demand and more than 45 GW of peak load by 2035 in the Base Demand case. In the High Demand case, growth from these drivers is even higher
2	Transmission expansion delivers net positive value in all scenarios, with system-wide NPV ranging from approximately \$4 billion to \$12.4 billion and benefit-cost ratios between 1.42 and 1.77 for the Base Demand case over a 40-year transmission economic lifetime
3	The Unconstrained case, which allows interregional links and greater line capacities than the Constrained case, produces roughly three times the NPV, with PJM accounting for the majority of these benefits owing to its large share of the selected transmission projects
4	In the High Demand case, benefits grow further, system-wide benefits NPV rises to about \$15.3 billion in the Unconstrained scenario, and more than doubles in Constrained scenario, resulting in a higher BCR of between 1.62 and 1.89 compared with the Base Demand case
5	Beyond these economic gains, transmission expansion lowers retail electricity rates, and enhances system reliability, resilience to extreme weather events
6	Transmission expansion can strengthen national defense by improving energy security and resilience for military installations, defense communities, and the defense industrial base

NPV: Net Present Value, BCR: Benefit-Cost Ratio
Source: S&P Global Energy

High value transmission expansion candidate solutions to relieve grid bottlenecks and support load growth

Core Study Objectives **01**
The focus of this study is to identify high value transmission solutions and their impacts on load growth, reliability, and national security, and affordability objectives

Scenarios **02**
Demand and transmission expansion scenarios are analyzed to identify where transmission congestion limits the ability to meet goals cost effectively and to quantify the customer benefits from resolving that congestion

Transmission Investment Value **03**
These transmission candidates represent well-planned, cost-effective intraregional and interregional transmission investments that relieve grid bottlenecks, ease tight supply conditions, and improve access to existing and new generation resources

Scope **04**
This is a high-level zonal analysis where all selected transmission expansion candidates are assumed to come online by 2035, with zero-line losses and no line outages. This assessment does not account for detailed routing or permitting

05 **Technical Configuration**
Selected transmission assumed to be 345 kV single-circuit lines, based on the zonal network configuration and optimal link capacities. These projects connect adjacent zones or states rather than long distance corridors

06 **Selection Criteria**
Selected candidates are based on multiple criteria, including utilization (which reflects volume) and the congestion score (which represents total impact, including severity and persistence)

07 **Geographic Footprint**
These candidates are distributed across the Eastern Interconnect, covering the entire U.S. side of the Eastern Interconnection except for MISO North

08 **Modeling Process**
Iterative process involving a Capacity Expansion Model and a Production Cost Model for optimal generation buildout

Source: S&P Global Energy

Selected transmission expansion projects aim to deliver affordability and reliability, while also driving National Security Priorities

Selected Transmission Expansion Candidates

Economic and Affordability

- The selected transmission projects deliver substantial net benefits, primarily through avoided local infrastructure investment and adjusted production cost savings
- The benefits have the potential to lower retail rates, saving money for customers

Reliability

- Selected transmission expansion candidates support system reliability by increasing transmission power flow
- Transmission expansion and interregional transmission enables access to lower-cost remote resources, reducing the need for more expensive local generation builds
- Transmission would also reduce exposure to extreme weather event driven energy price premiums, improve reserve sharing and reduce balancing costs

National Security and Defense

- Congress has required the Department of War to coordinate on grid reliability and transmission infrastructure to mitigate risks to mission critical loads and infrastructure[1]
- Transmission that increases system reliability helps military missions attain their energy availability requirements[2]
- Military missions depend on the infrastructure and personnel in surrounding defense communities. Transmission expansion that reduces the risk of regional power outages reduces risks to mission assurance[3]
- Transmission can alleviate defense production surges during periods of conflict, and can increase resilience for the defense industrial base[4]

1. FY26 NDAA Section 2847, 2. 10 U.S.C. 2920, 3. Transmission Expansion for National Defense (TREND), 4. Powering the Fight
Source: S&P Global Energy

The high-level benefit-cost assessment evaluates the economic, affordability, reliability, and national security impacts of the selected transmission expansion projects

Theme	Main drivers	Slide where theme is covered
Economic and Affordability	Avoided capital and operational costs compared to more costly infrastructure developed locally	▪ Benefit-cost analysis for Base Demand (slides 42-51) and High Demand Case (slides 55-64)
	Reduction in retail electricity rates for customers	▪ Retail Rates Analysis for Base Demand (slide 52) and High Demand case (slide 65)
Reliability	Reduced reliability risk by enhancing system reliability through increased power transfer capacity. Reduced generation build needs by enabling access to lower-cost remote resources and thereby limiting reliance on more expensive local generation	▪ Adjusted production cost savings for Base Demand (slides 46-47) and High Demand Case (slides 59-60)
	Reduced exposure to extreme weather driven price spikes, improved reserve sharing, and lower balancing costs	▪ Ancillary Services and Extreme Weather Impacts (slides 67-68)
National Security and Defense Aspect	Strengthen military installation resilience through improved grid reliability and reduced exposure to outage risk that on-site generation alone cannot address	▪ Transmission expansion supports critical defense missions across the nation, with interregional infrastructure mitigating the potential of cascading operational risks (slides 73-74)
	Reduced risk of long-duration power outages to defense communities, and the critical civilian infrastructure that military missions depend on	▪ Mission dependence on civilian infrastructure and surrounding defense communities (slides 75-76)
	Avoided disruptions in production for the defense industrial base	▪ Nationally networked defense industrial base and the importance of reliable energy infrastructure in supply chain durability (slides 77-79)

Source: S&P Global Energy

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Overview

Iterative Transmission Expansion Design for Economic and National Security

Inputs

- Demand Growth Projection
- Initial Grid Expansion Configuration
- Transmission Candidates
- Existing Generation Portfolio
- Capital and Operation Costs
- Technology Characteristics
- Policies & Regulations

Capacity Expansion Modeling

Zonal Production Cost Modeling in Aurora

AURORA
BY ENERGY EXEMPLAR

Outputs

- Transmission Expansion Configuration
- Generation Buildout
- Total and adjusted System Costs
- Generation Mix
- Fuel and Emission Costs
- Transmission Congestion and spread
- Reserve Margin Benefits

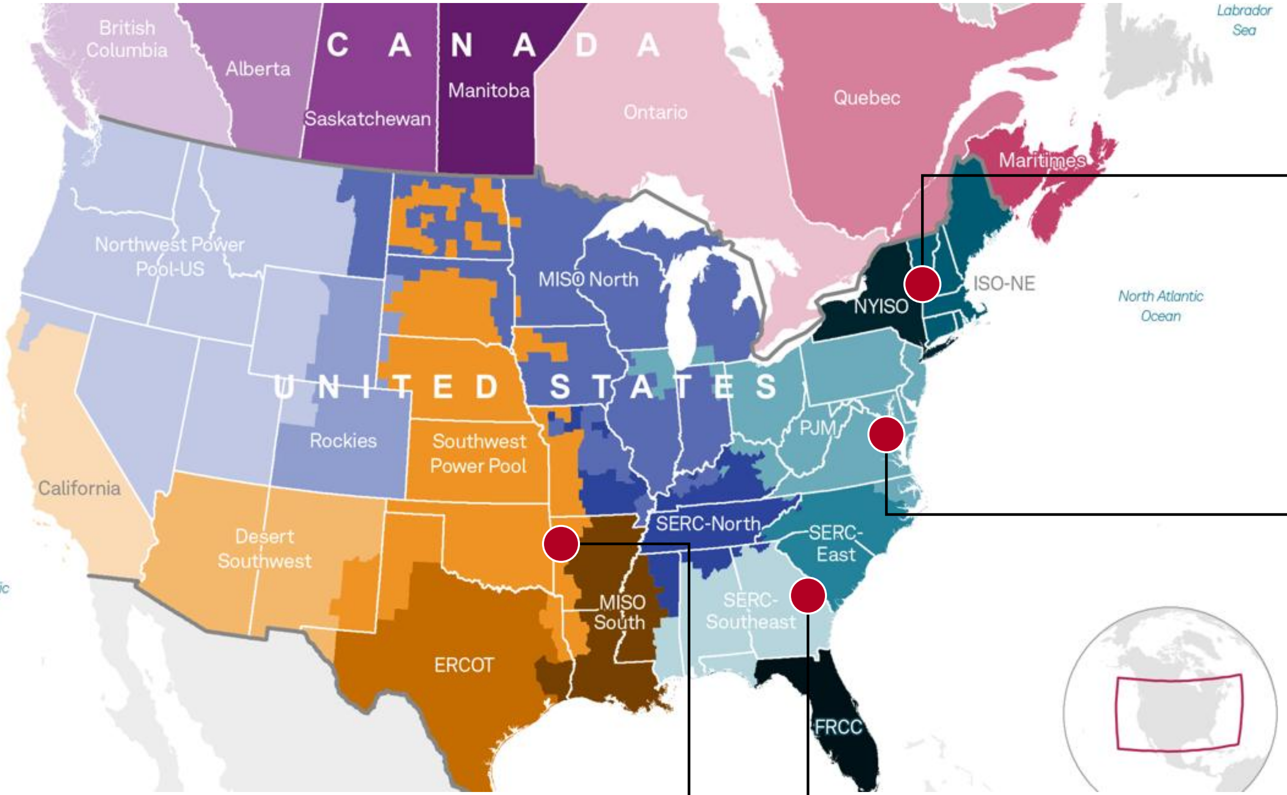
This study covers four major Region Centers in the U.S., and all of them are in the Eastern Interconnect

- **Capacity Expansion Model:** Leverage data and results from the core scope to populate S&P's proprietary Capacity Expansion Model (CEM) while incorporating the model constraints
- **Production Cost Model:** Evaluate the operational impacts of the final capacity buildout on generation mix, prices, VRE curtailment, transmission congestion, and emissions, etc. using Aurora
- An **iterative methodology** is implemented that begins with some of the targeted expansion projects based on various existing transmission expansion studies like the National Transmission Planning Study (NTPS), National Transmission Needs Study (NTNS), and Regional Transmission Expansion Plans (RTEP) and iteratively adjusts the new transmission buildout and optimal generation buildout/ capacity expansion to provide for the economic and national security goals
- While HVDC and HVAC technologies are integral to our discussions, they do not fundamentally alter our zonal modeling approach. We are operating under the assumption that the selected transmission expansion projects offers greater flexibility than it may realistically provide

Source: S&P Global Energy

Four selected region centers prioritizing affordability, load growth, and interregional transmission

We focused on the Eastern Interconnection (EIC) to provide a more robust analysis. Several recent comprehensive studies had been initiated or completed in the Western Interconnection. Because all four region centers are within the EIC, simulating the entire EIC allowed for a more comprehensive analysis of market interactions and enabled coordinated capacity expansion



Affordability | National Security | Interregional Transmission

Northeast: This region is one of the epicenters of concerns about the affordability of energy bills. NECEC, CHPE, and other future transmission projects between the U.S. and Canada make this region interesting

AI Load Growth | National Security | Interregional Transmission

PJM: Northern Virginia has the largest concentration of existing and planned datacenters globally. The Chicago and Columbus areas in PJM West also have significant potential. Additionally, several 500 and 765 kV transmission projects are being proposed

Affordability | AI Load Growth | National Security | Interregional Transmission

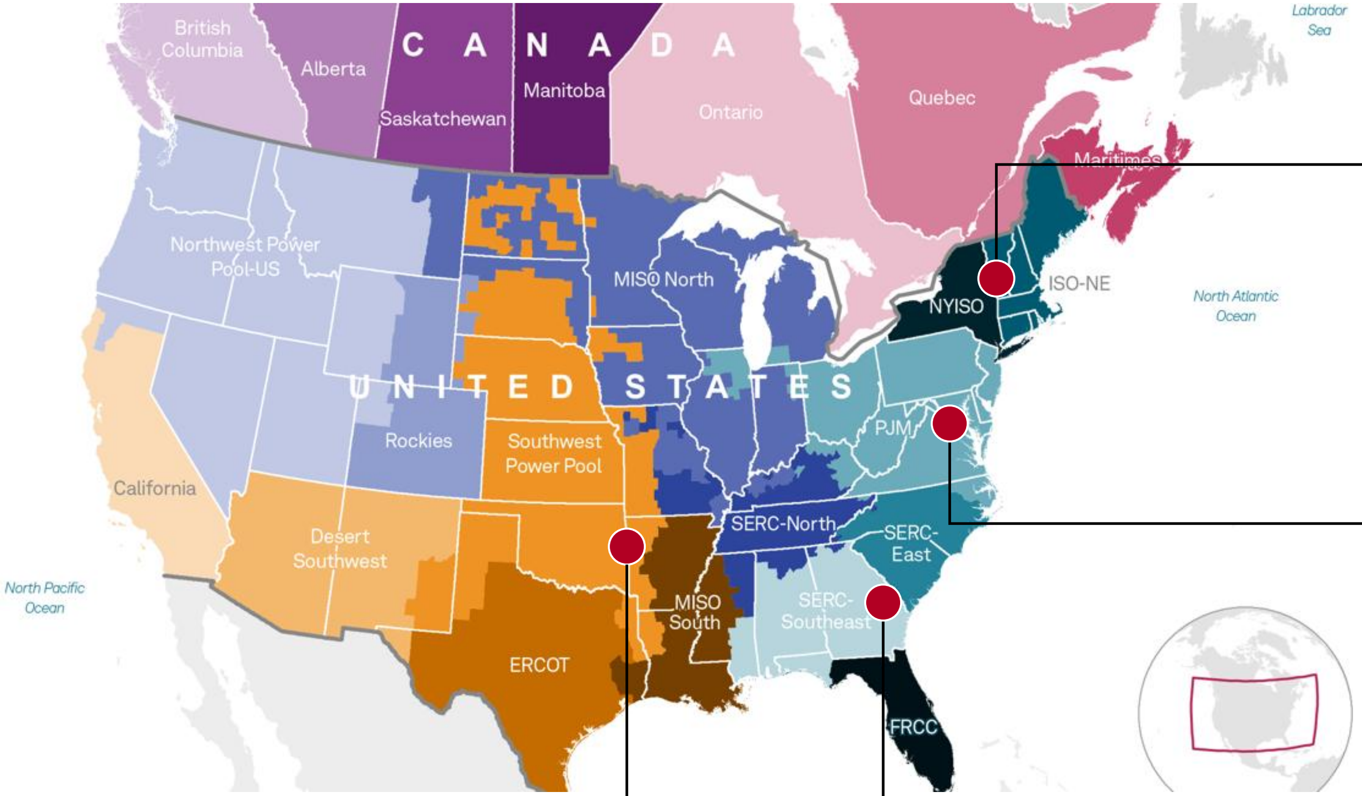
SERC: Atlanta leads the Southeast in AI and cryptocurrency datacenters, while Mississippi is poised for substantial datacenter growth. The region offers strong industrial load and economic expansion potential. SERC faces affordability challenges but stands to gain significantly from enhanced interregional transmission

AI + Manufacturing and Industrial Load Growth | National Security | Interregional Transmission

SPP + MISO S: In SPP, Kansas City and Omaha are primary datacenter hubs. MISO South, particularly Louisiana, shows strong potential for datacenter growth. SPP is considering 765 kV interregional projects in SPP South, while MISO South will benefit from MISO Tranche 3 and 4 projects to relieve congestion. Louisiana is also a major hub for refining, petrochemicals, chemical manufacturing, and other industrial activities

Source: S&P Global Energy

The four selected region centers include military installations and missions that are critical to national security and defense



*Affordability | **National Security** | Interregional Transmission*

Northeast: The region includes extensive undersea warfare capabilities in advanced cyber, space-warning, and aircraft missions, and one of the country's largest defense industrial bases

*AI Load Growth | **National Security** | Interregional Transmission*

PJM: PJM houses some of the nation's most critical defense assets, including Fort Meade, Naval Station Norfolk, and Wright-Patterson AFB. The National Capital Region includes the Pentagon and national command, cyber, and intelligence missions

*Affordability | AI Load Growth | **National Security** | Interregional Transmission*

SERC: Home to Fort Bragg's special operations forces, Redstone Arsenal's missile and space missions, Fort Gordon's intelligence and cyber operations, and a Marine Corps network spanning the Carolinas and Georgia. For the National Security analysis, the focus is given more to the southeastern states

*AI + Manufacturing and Industrial Load Growth | **National Security** | Interregional Transmission*

SPP + MISO S: A north-south corridor that runs from Ellsworth Air Force Base (AFB), through Offutt AFB in Nebraska (home to U.S. Strategic Command), to Barksdale AFB in Louisiana, which contain bomber missions that anchor strategic deterrence

Source: S&P Global Energy

The analysis spans four scenarios, pairing Base or High Demand with Constrained or Unconstrained transmission

High Demand due to AI, manufacturing, and industrial growth

Scenario C **High Demand** Unconstrained Transmission	**Scenario D** **High Demand** Constrained Transmission
Scenario B **Base Demand** Unconstrained Transmission	**Scenario A** **Base Demand** Constrained Transmission

Unconstrained Transmission
Less need for generation sited closer to load and enables system wide least cost transmission optimization

Constrained Transmission
More need for generation sited closer to load

Base Demand (S&P Integrated House View)

- This matrix explores four future scenarios by crossing demand growth with transmission constraints
- All of these scenarios incorporate advanced generation technologies, including advanced geothermal and advanced nuclear, and assess the impacts of ATTs
- National security and defense implications are integrated across all four scenarios to provide a comprehensive perspective

Source: S&P Global Energy

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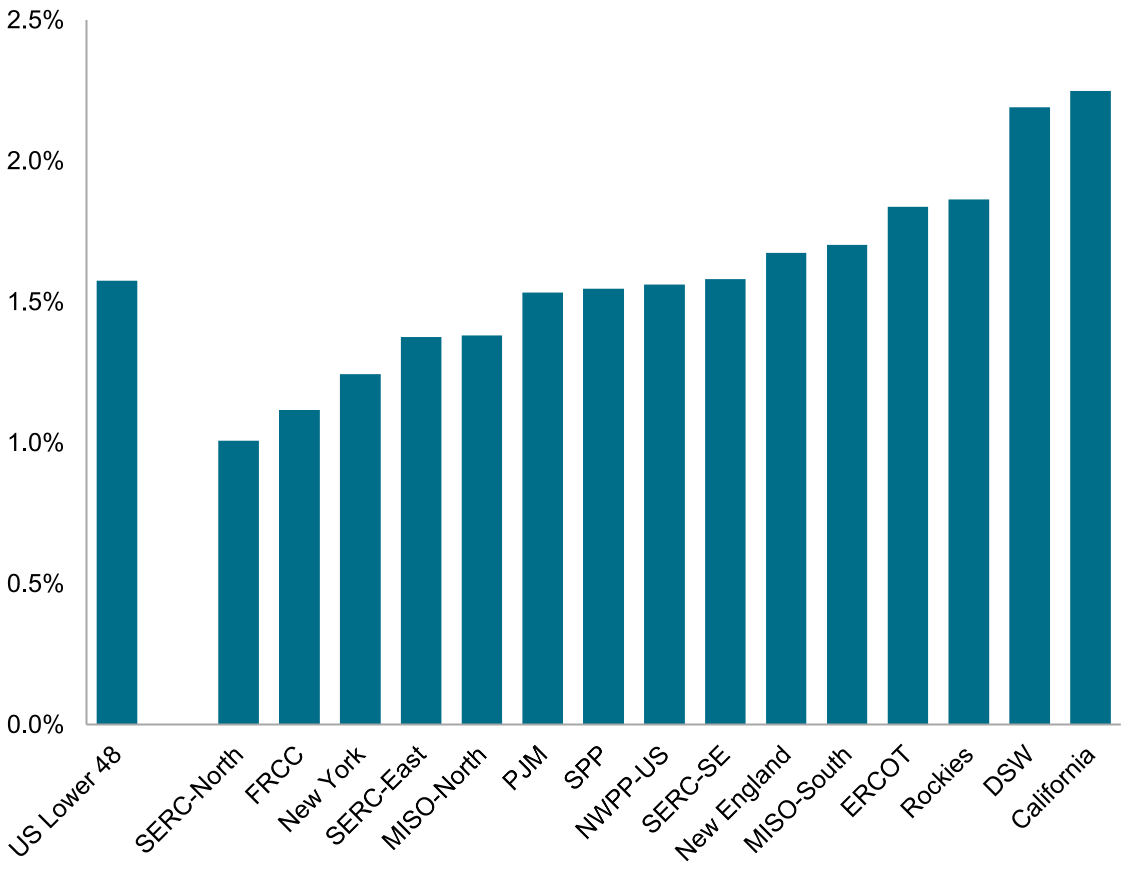
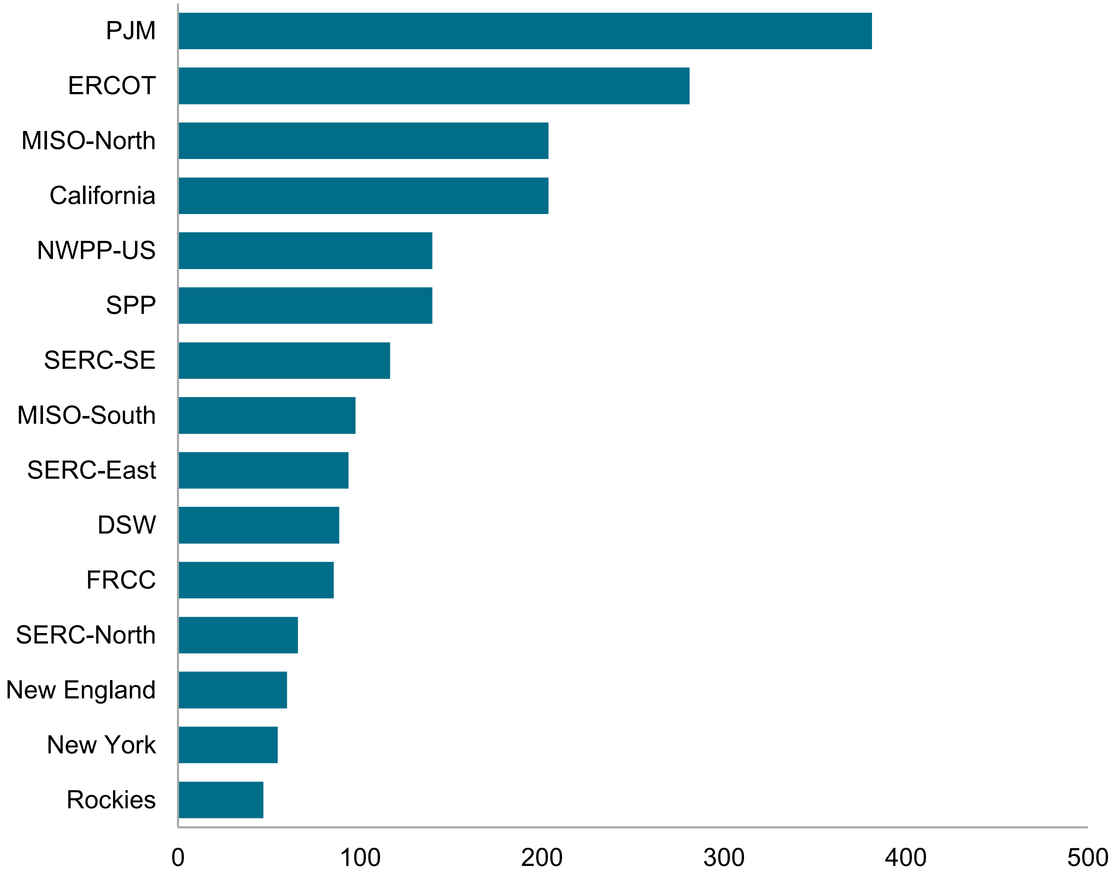
Datacenter demand is the main driver of medium-term growth, with over half of the projected increase concentrated in PJM and ERCOT

CAGR of net on-grid electricity demand by region, 2025-50



Growth in net on-grid electricity demand by region, 2025-50
(TWh)

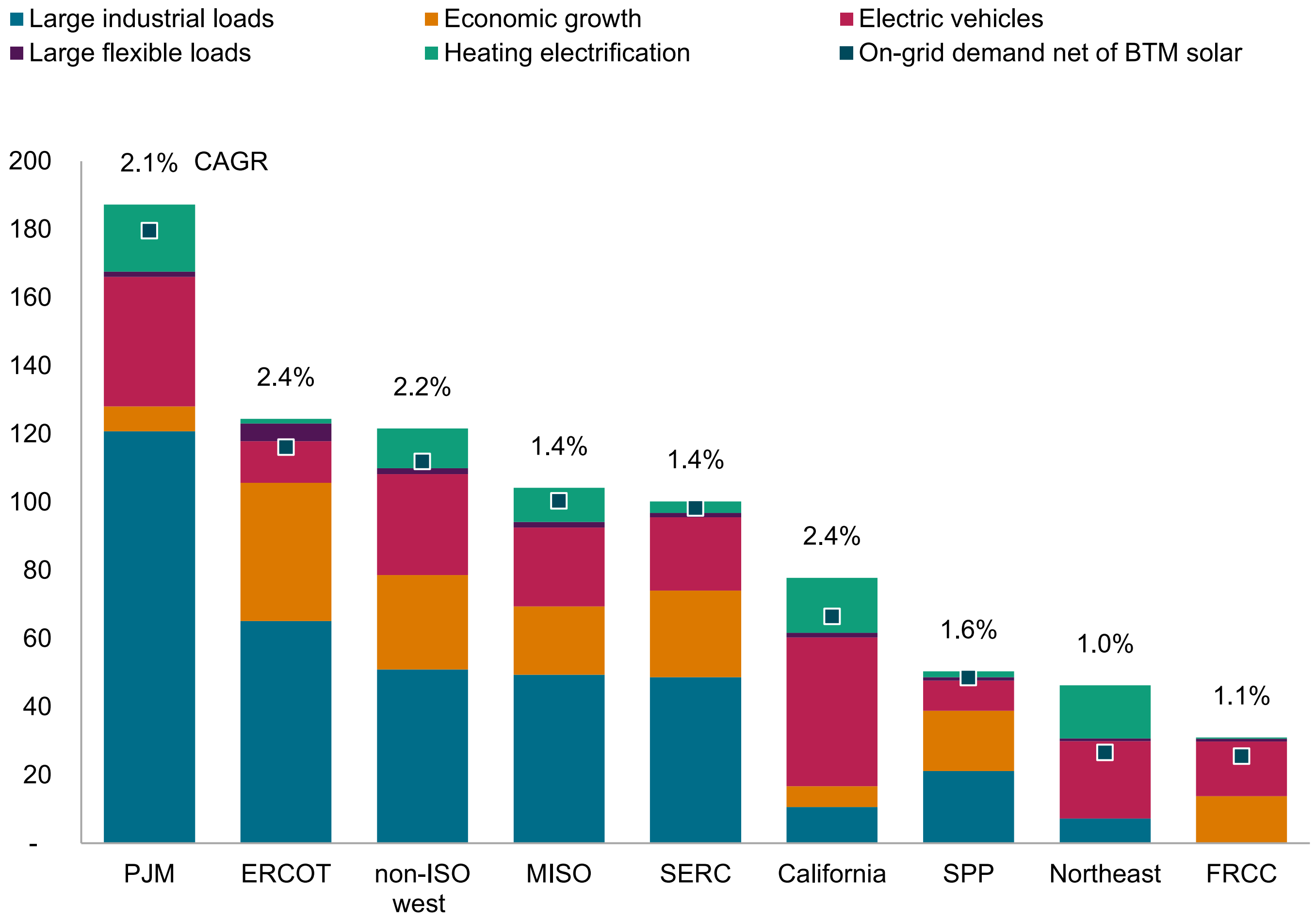


Data compiled December 2025. CAGR: Compound Annual Growth Rate. Net on-grid electricity demand reflects the impact of BTM solar PV.
Source: S&P Global Energy

Datacenters and electrification along with economic growth propel demand through 2035

US electricity demand growth by driver, 2025-2035

TWh



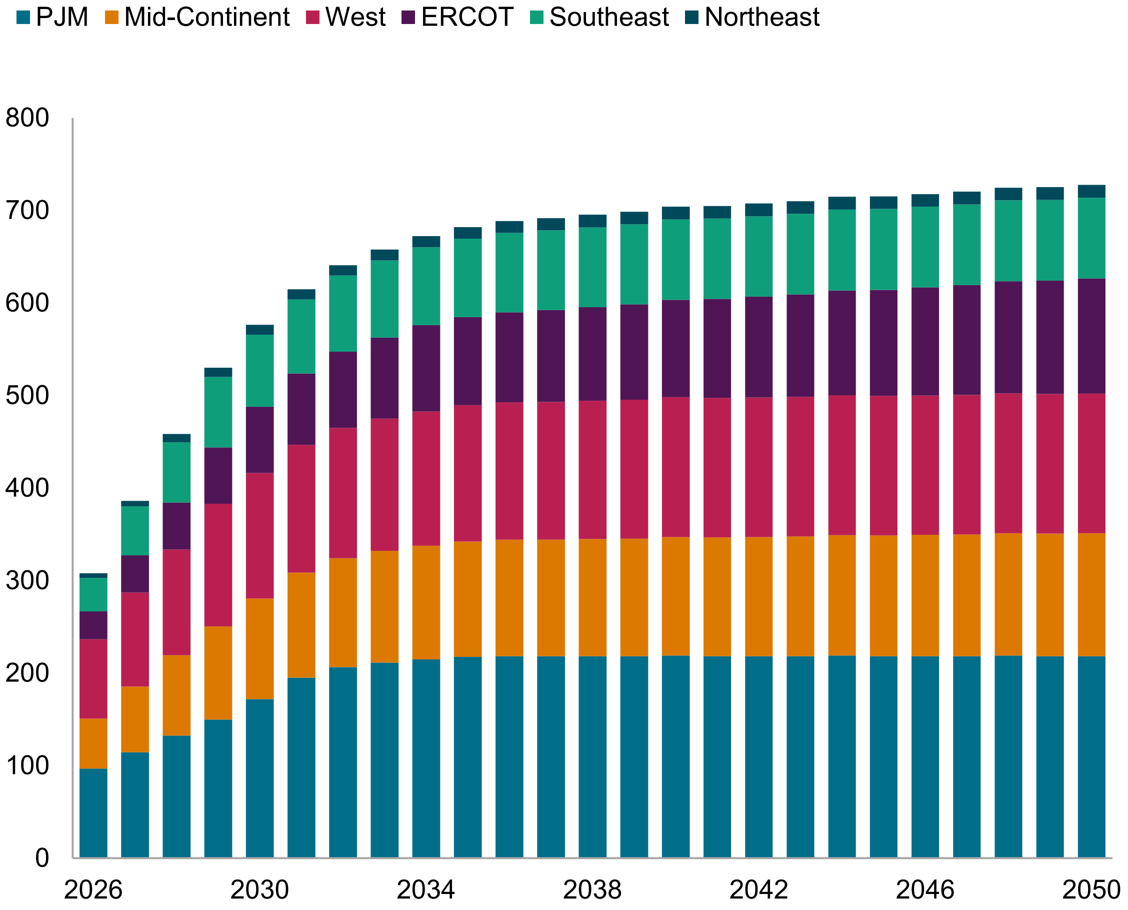
Data compiled December 2025. CAGR: Compound Annual Growth Rate.
Source: S&P Global Energy

- **Large industrial loads—especially datacenters and new manufacturing—drive the bulk of US electricity demand growth through the mid 2030s**, adding 374 TWh of energy demand and more than 45 GW of peak load by 2035, before efficiency gains begin to moderate growth
- This load growth is highly regional, with PJM and ERCOT alone accounting for one-third, though rising costs and grid constraints are pushing new datacenter development into new markets like Mississippi, Louisiana, and Arizona
- Electrification, in the form of EVs and heat pumps, are the second biggest demand driver through 2035—adding 295 TWh, though much of that does not materialize until the 2030s. Longer term, electrification is by far the dominant driver of new demand growth
- Behind-the-meter solar offsets roughly 7.5% of load growth over the next decade, with rising retail rates driving adoption after federal tax credits phase out
- Underlying economic growth (~1.7% GDP annually) provides a stable backdrop, supporting steady baseline electricity demand across sectors
- Growing electricity demand also reflects the military's shift toward electrified, stateside missions — from cyber warfare to remotely piloted aircraft support — that make domestic installations direct participants in operations

Emergence of new, large industrial load centers is projected to spur electricity demand growth, particularly in the near term

US Lower 48 electricity demand from large industrial loads

TWh



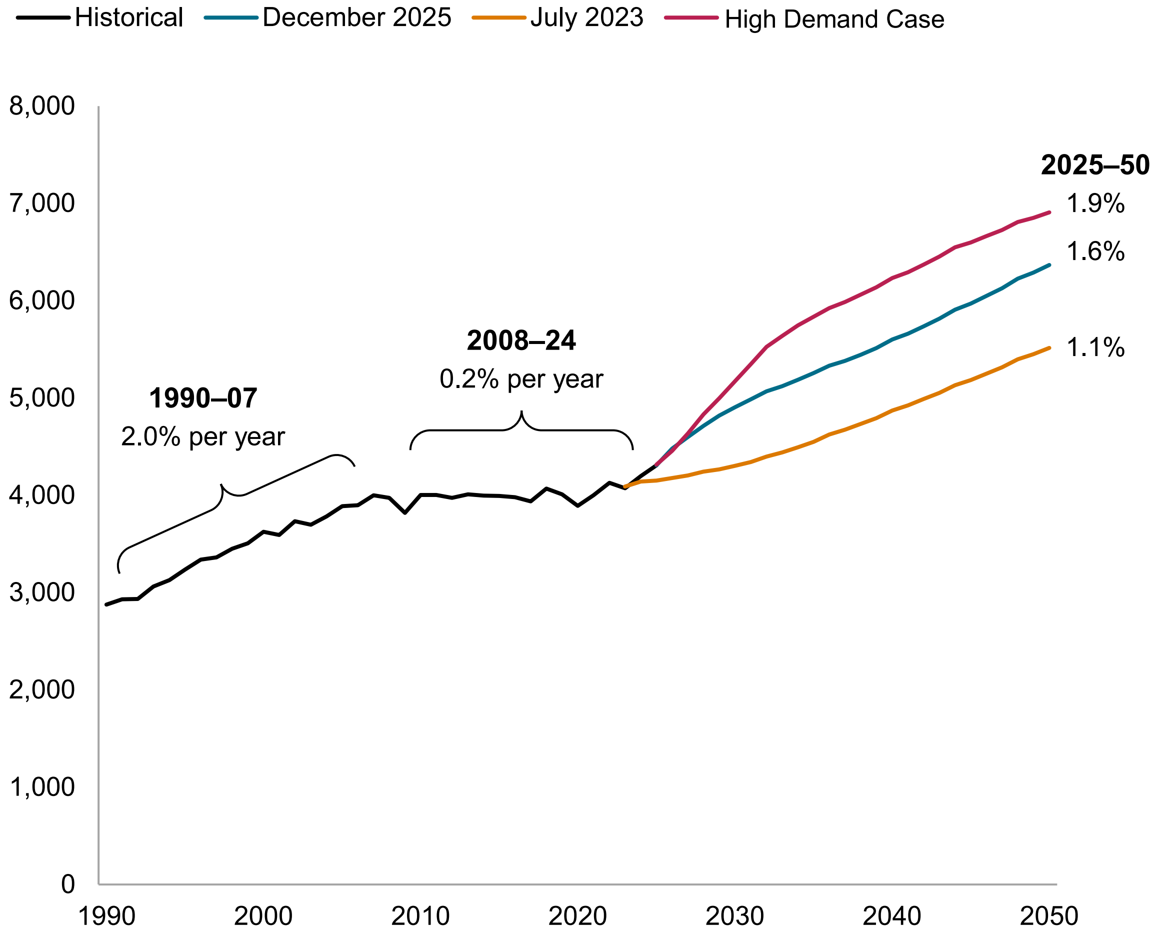
- **Electricity demand from datacenters and other large industrial facilities drive significant load growth, especially through the early 2030s**
  - Large industrial loads refer to demand driven by datacenters, other large industrial facilities (e.g., semiconductor fabrication, solar, and battery manufacturing), and the electrification of oil and gas operations
  - In the coming years, large industrial loads will drive strong growth in US electricity demand after years of stagnation. By 2030, incremental demand growth attributed to large industrial loads reaches 270 TWh—compared to 540 TWh in our 2025 High Demand case. Growth from large industrial loads is regionally concentrated in PJM and ERCOT, together accounting for over half of the growth
  - In the IHV, growth in grid-based demand from large loads is constrained by the insufficient pace of generation and transmission capacity expansion. Regionally, grid capacity is expected to constrain large industrial load growth (on-grid) the most in PJM and ERCOT
  - Rising costs and regional grid constraints are driving expansion beyond traditional datacenter regions like Northern Virginia into less traditional markets that have yet to see substantial datacenter development, such as Mississippi, Wisconsin, North Dakota, and Louisiana
  - Datacenters and other large industrial loads will drive strong regional growth in peak demand as they tend to operate at relatively high load factors. By 2030, large industrial loads contribute over 70 GW to total US peak demand (33 GW incremental from a 2026 base year)
  - The 2026 National Defense Strategy[1] calls for "supercharging" the U.S. defense industrial base, an objective that will increase electricity demand from munitions production, shipbuilding, and advanced manufacturing facilities concentrated in PJM, SPP+MISO S, and other regions already strained by datacenter growth

Data compiled December 2025. 1. Department of War, *2026 National Defense Strategy*, January 2026, as cited in Converge Strategies and Energy Strategies, *Unleashing Virginia*, August 2026.
Source: S&P Global Energy

Power demand climbs amid datacenters and economic growth

US Lower 48 net on-grid electricity demand by outlook vintage

TWh



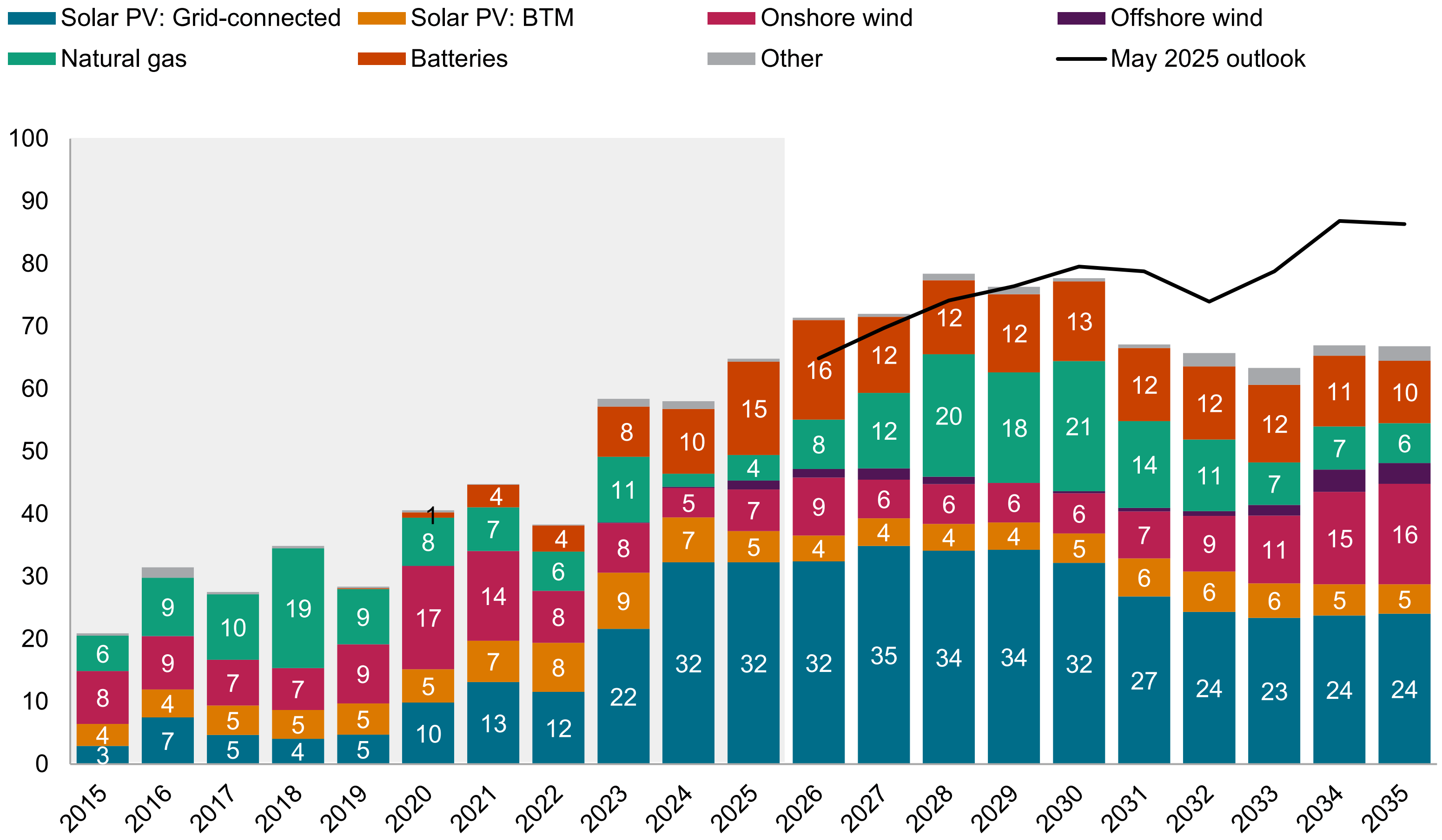
Data compiled December 2025.
Source: S&P Global Energy and EIA for historical data

- **Electricity demand is anticipated to grow at a 1.6% CAGR over the next 25 years, driven by strong economic growth, datacenters in the near-term, and electric vehicles in the long-term**
- Large industrial loads—primarily datacenters—are expected to drive strong growth through 2030, with incremental demand from these sources reaching 270 TWh. Datacenter demand is expected to be regionally concentrated in PJM and ERCOT, which together account for more than half of the projected increase
- Prior to the datacenter boom (July 2023 outlook), demand growth was already expected to be at a 1.1% CAGR—driven by electric vehicles and economic development. The datacenter growth expectations have greatly increased the near-term outlook in the December 2025 outlook, yet the long-term remains mostly consistent with the July 2023 outlook
- The High Demand scenario anticipates robust growth in the near-term predominately driven by datacenters. Demand growth is at a 3.5% CAGR between 2024-2030, compared to 2.4% in the December 2025 outlook
- In the long-term, demand continues to be driven by electric vehicles and economic growth. US light vehicle EV adoption is expected to reach 7% by 2030 and 58% by 2050, representing 900 TWh in 2050, or 14% of total US net on-grid demand. US GDP growth is expected to grow at a 1.7% CAGR between 2025-2050, in line with electricity growth

Solar and gas lead new capacity additions through the demand surge

US lower-48 nameplate capacity additions

GW



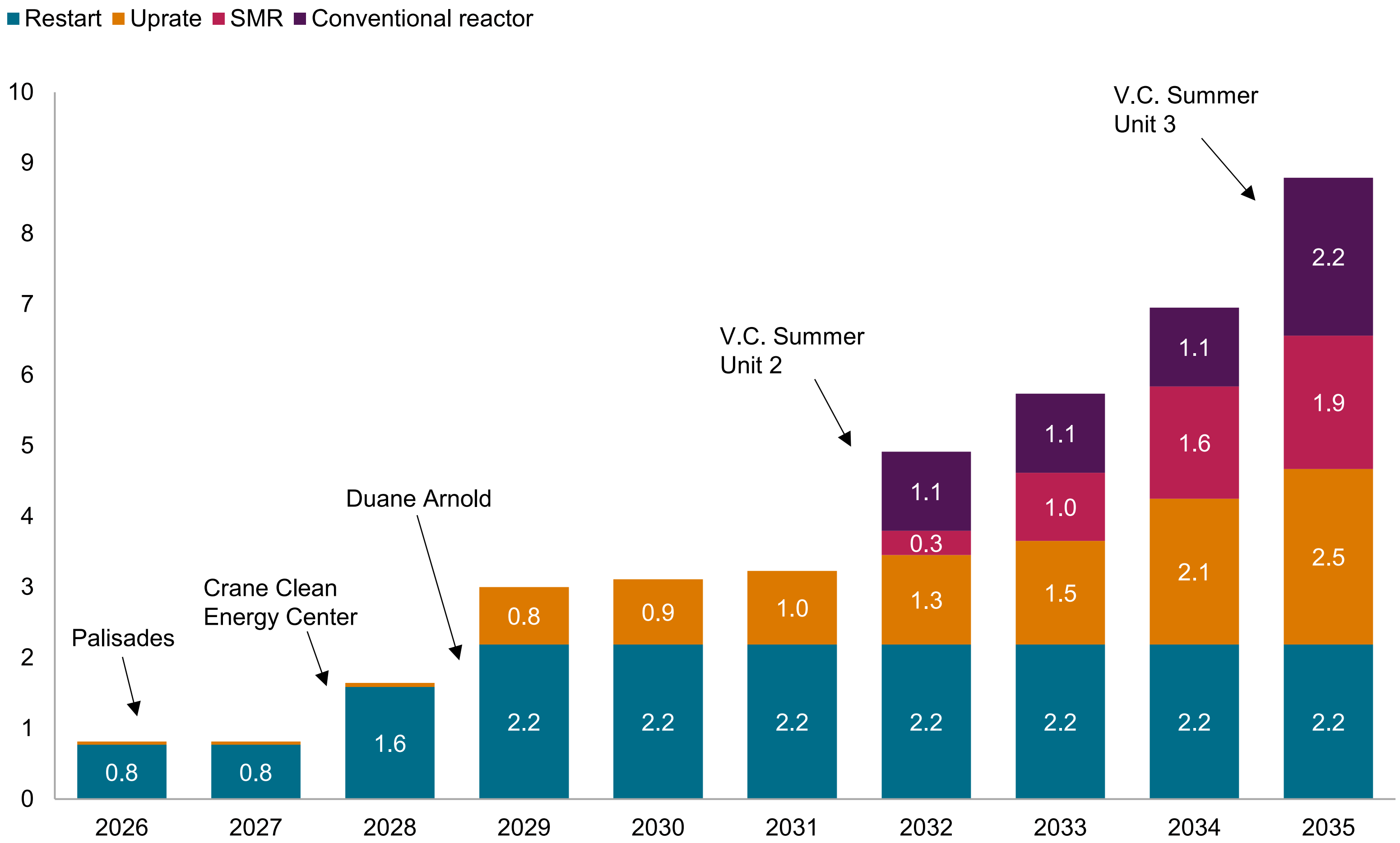
- Solar additions remain strong through 2030 as developers pull projects forward to secure expiring tax credits, with additions peaking in 2027 before slowing as the pipeline is depleted. State and corporate clean energy targets and competitive economics prop up additions thereafter
- Gas additions rise quickly to meet datacenter driven demand growth, peaking at 21 GW in 2030
- The onshore wind sector expands at a modest pace as it struggles to overcome permitting obstacles, siting limits, and policy headwinds. Additions are concentrated in the middle of the country and increasingly comprise of repowered wind farms. The offshore wind sector remains largely stalled except for projects already under construction
- Battery deployment surges ahead of new FEOC restrictions before settling into a 10-12 GW annual market, driven by demand for dispatchable clean energy and solar-driven price volatility
- The nuclear fleet begins to grow again in the 2030s through a mix of new reactors, both SMRs and conventional

Data compiled December 2025.
Source: S&P Global Energy

Nuclear additions will accelerate, first with restarts and uprates then with new builds

US cumulative nuclear additions

GW



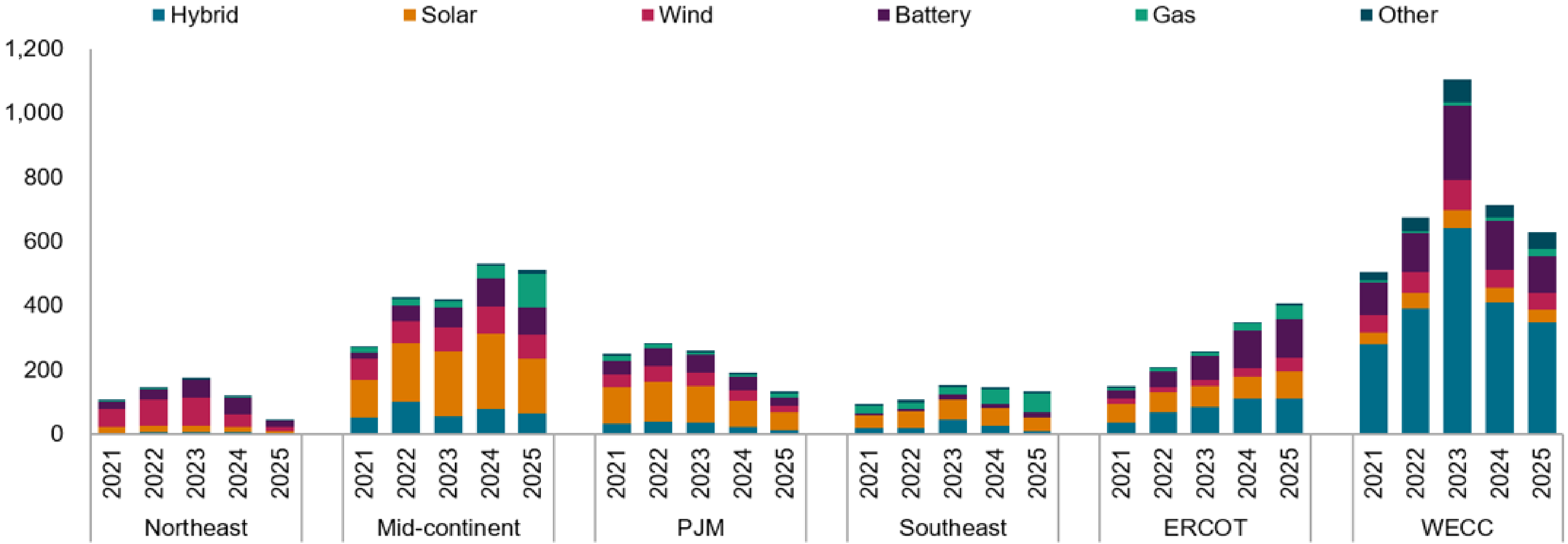
Data compiled December 2025. SMR: Small Modular Reactor. See A Nuclear Uprate Wave is Coming.

Source: S&P Global Energy

- **The nuclear fleet is poised to grow, first through reactor restarts and uprates, followed by new build SMRs and AP1000s**
- Before 2032, all US nuclear additions are expected to be the restart of existing reactors (Palisades, Crane Clean Energy Center, and Duane Arnold) and uprates at existing plants
- Uprate are expected to coincide with life-extension projects in the early 2030s as reactors approach 60 years of operation. By 2035, several dozen uprate projects are anticipated, with 1100 MW concentrated in PJM
- SMR deployment is expected to begin in the early 2030s, led by the Oklo Aurora Powerhouse project in Idaho, Natrium Power project in Wyoming, and Clinch River project in Tennessee. By 2035, 1900 MW of SMRs are anticipated
- Through executive actions, strategic partnerships, and financial commitments, the Trump administration has reenergized the idea of building AP1000s. The completion of the partial built V.C. Summer units in South Carolina are expected to come online in 2032 and 2035

Interconnection queues—a leading indicator of new supply trends—continue to be dominated by renewables, with growing amounts of gas as well

Interconnection queues, active capacity
GW

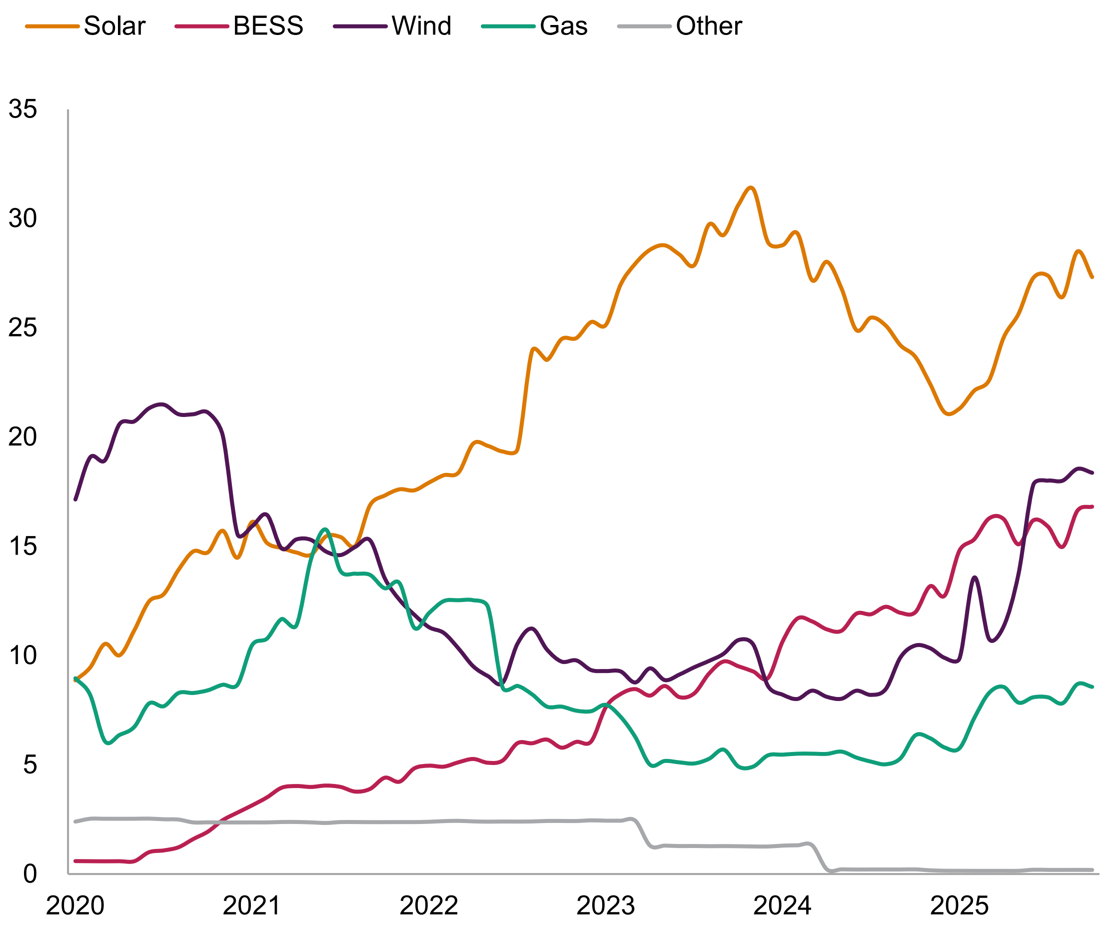


Near-term supply additions are evaluated based on resources with executed interconnection agreements and projects currently in the interconnection queue. Not all resources with interconnection agreements or queue positions are expected to reach commercial operation. Project attrition can result from financing constraints, local opposition, permitting delays, extended queue timelines, or changes in market fundamentals that reduce the economic need for the facility. Historical queue-to-construction conversion rates are applied by region to estimate the portion of queued capacity likely to be developed. This approach reflects observed project completion trends and accounts for regional differences in interconnection processes, permitting conditions, and market dynamics. Large-scale projects, including gas and nuclear units, are assessed using additional commissioning likelihood indicators. Key considerations include project maturity, financing status, the durability of underlying demand or contracted support, and the procurement of critical long-lead equipment, such as firm turbine orders

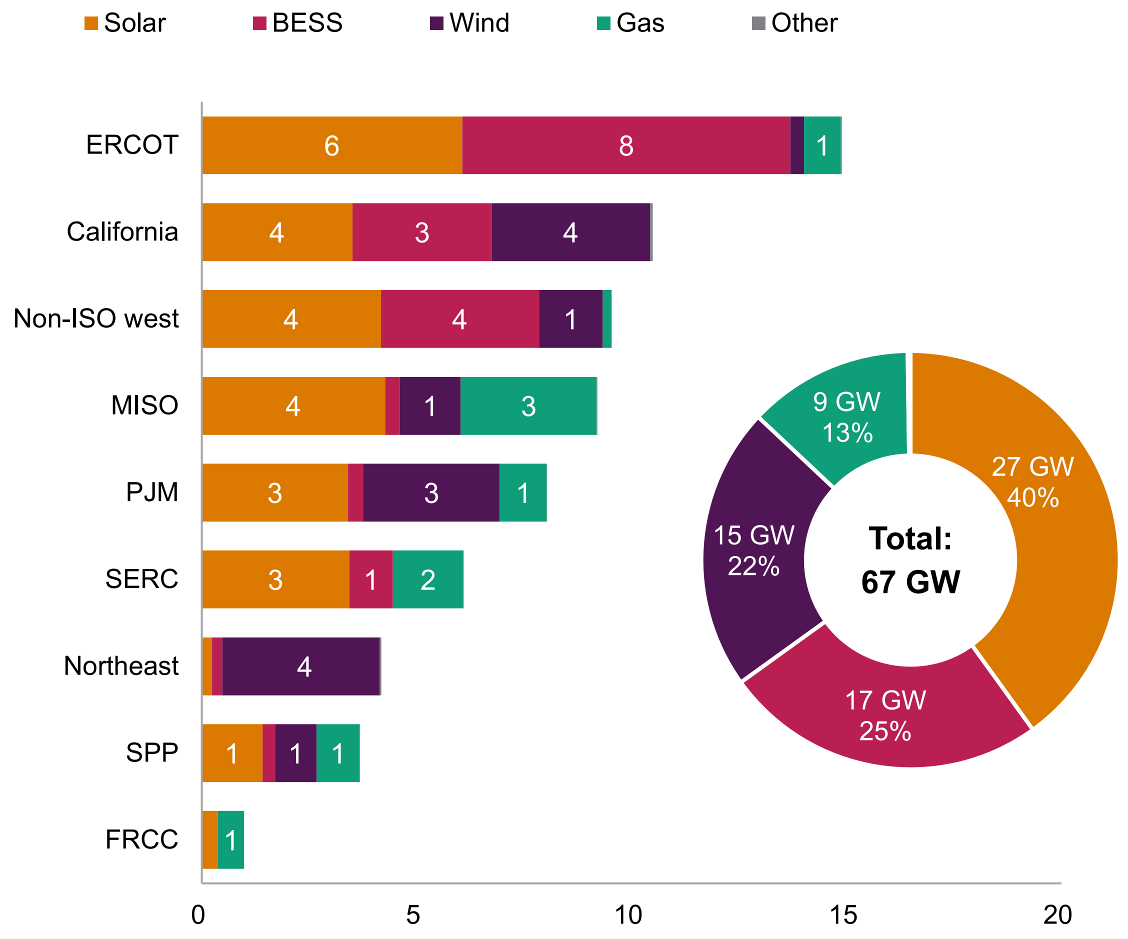
Data compiled December 2025. Notes: Mid-continent includes MISO and SPP. Northeast includes ISONE and NYISO.
Source: S&P Global Energy

US power supply under construction is at its highest level in recent history

US power supply under construction by month
GW



US power supply under construction by region (GW)
GW

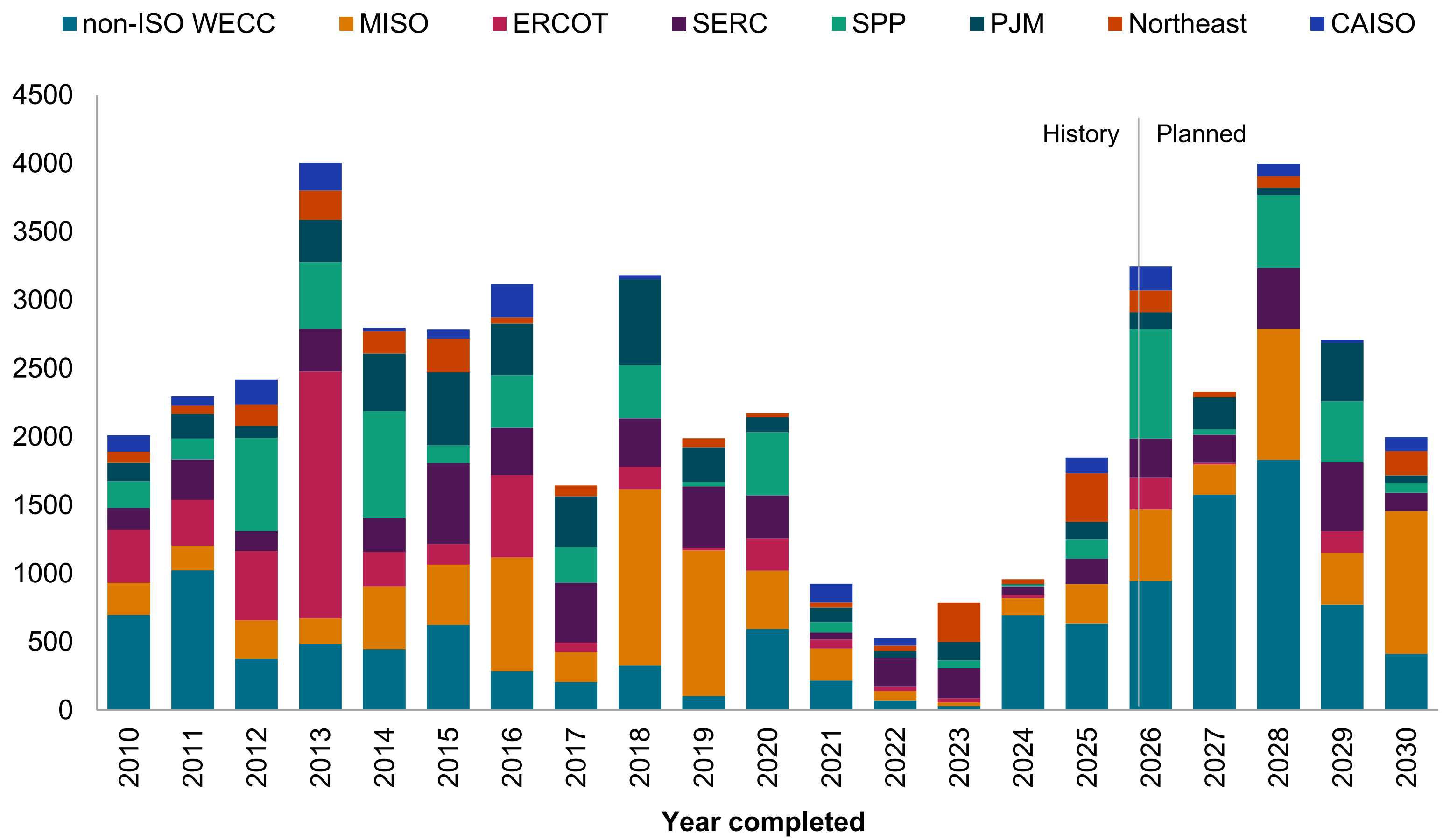


Data compiled November 2025. Wind includes onshore and offshore wind. Solar includes only grid-facing, not behind-the-meter.
Source: S&P Global Energy and US Energy Information Administration

Transmission development is expected to grow again after recent slowdown, with the largest expansions planned in the WECC and MISO

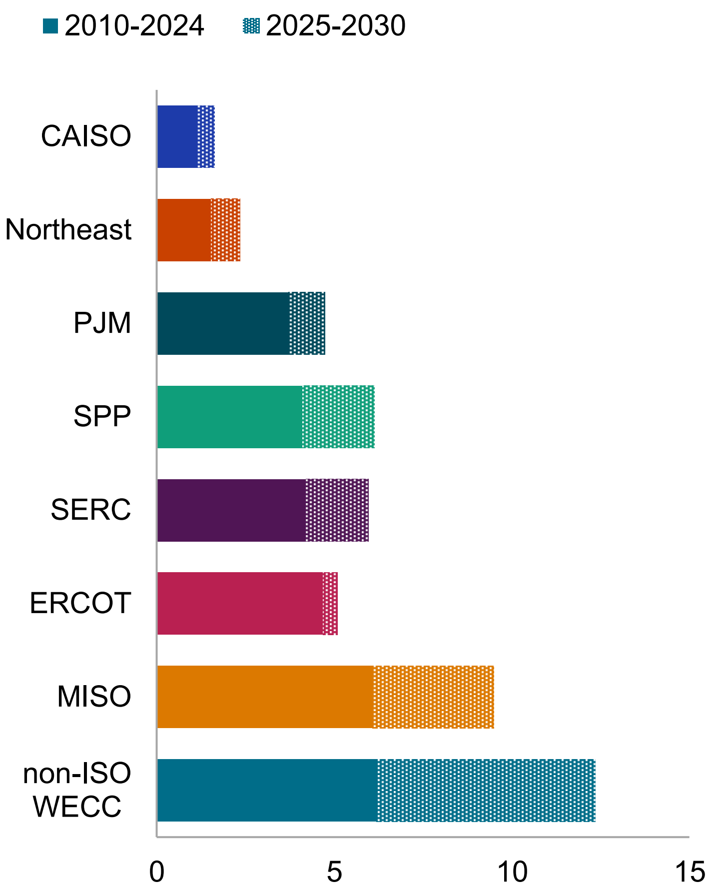
US transmission development

miles of high-voltage lines



Transmission development by region

thousand miles



Data compiled November 2025.
Source: S&P Global Energy

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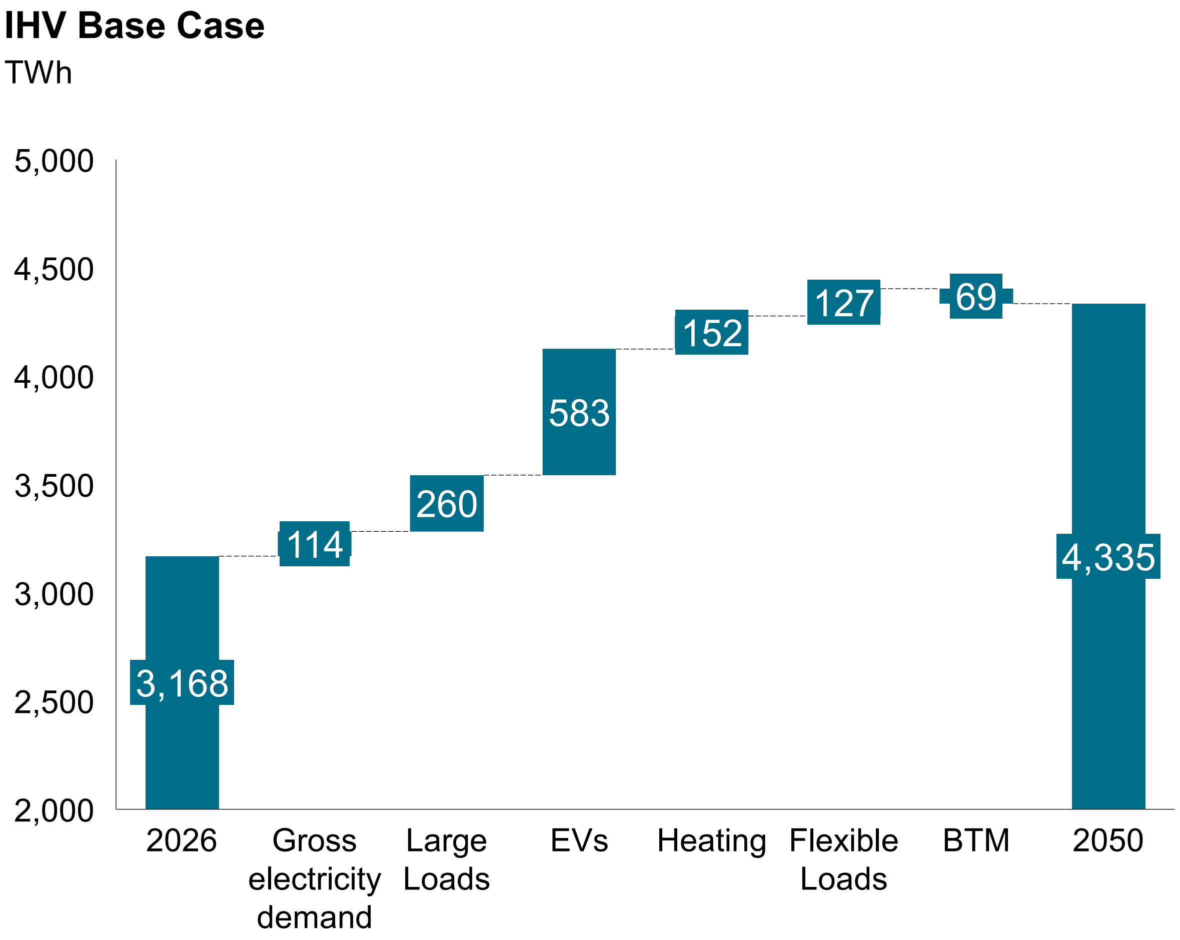
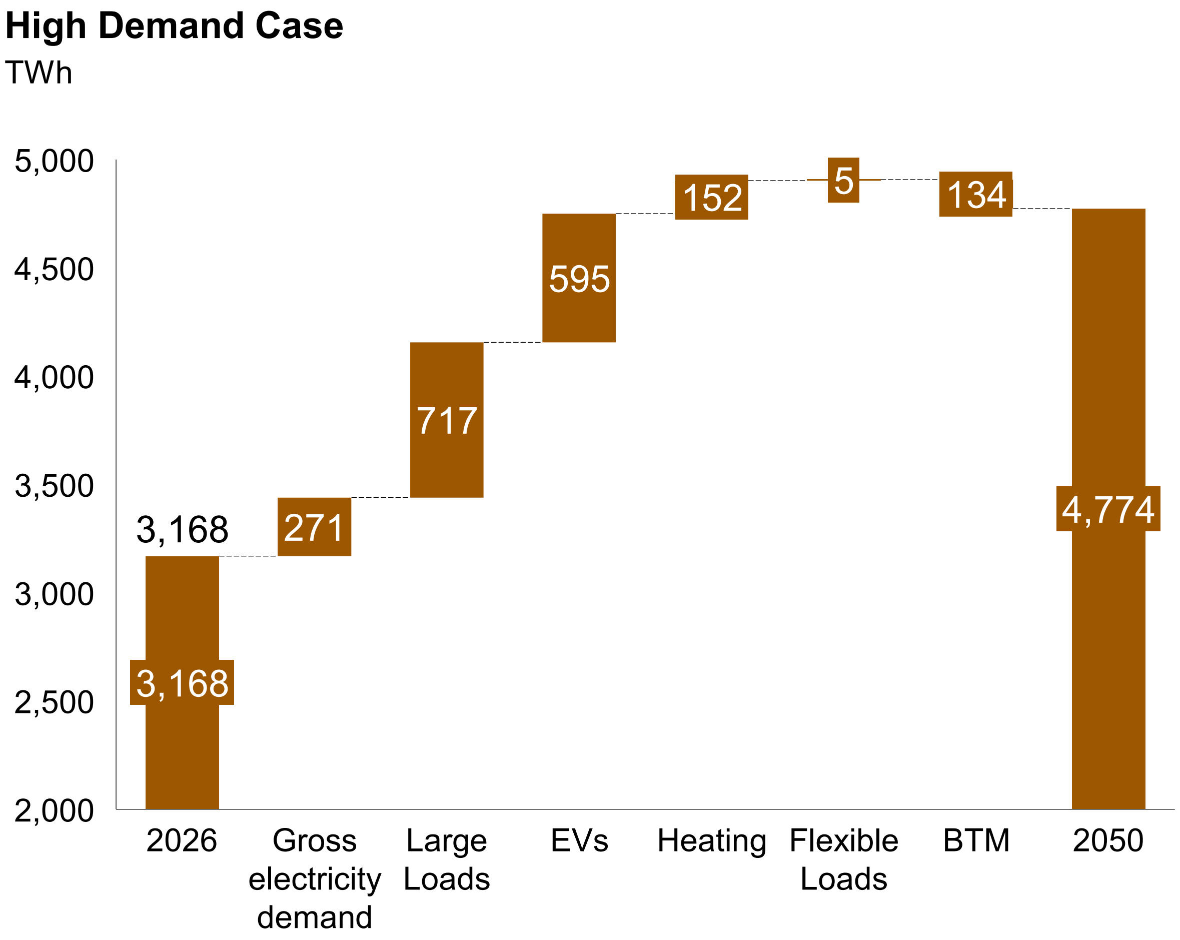
Higher demand is driven by large loads, primarily datacenters

Annual Energy Demand for Eastern Interconnect (U.S.)





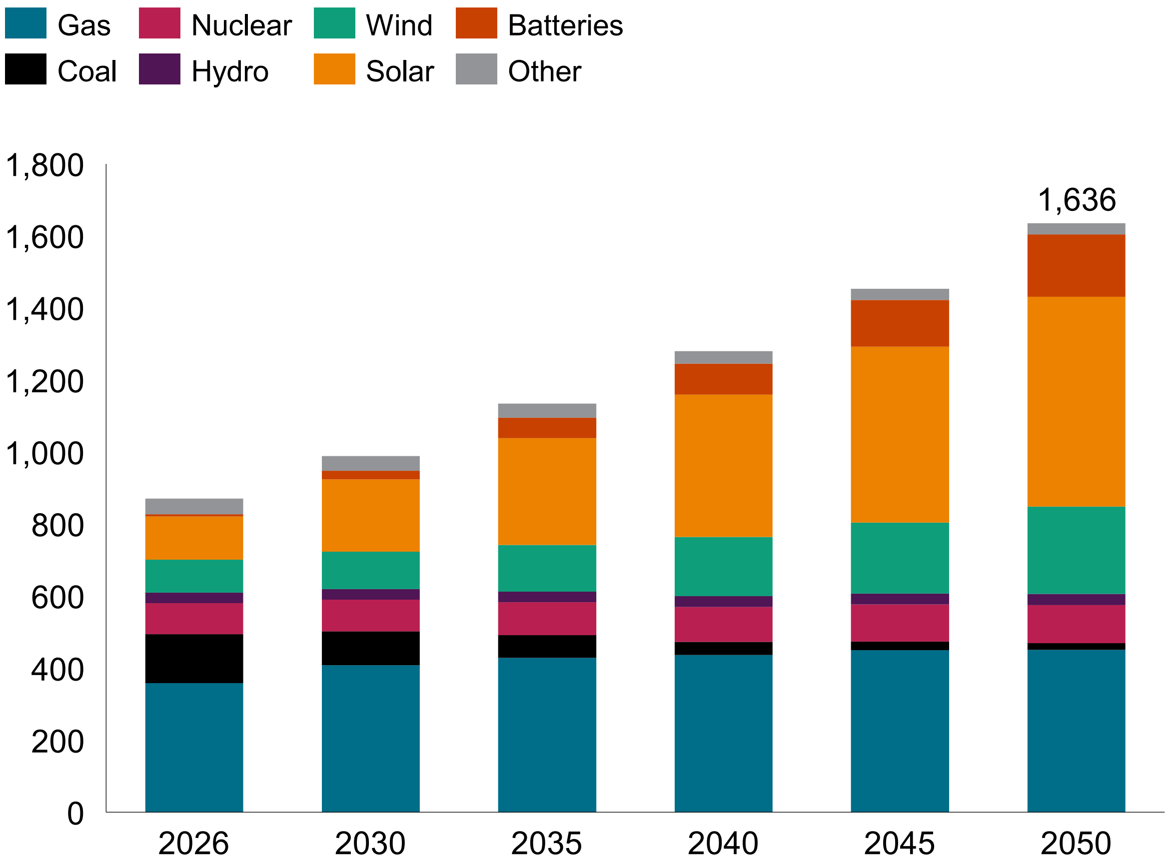
1. Large industrial load, heating electrification, and large flexible loads in this chart are incremental. Flexible loads include hydrogen electrolyzers and crypto mining whereas large loads include datacenters, manufacturing, and industrial loads.
Source: S&P Global Energy

The High Demand case has more renewables and nuclear

Operating Capacity for Eastern Interconnect (U.S.)

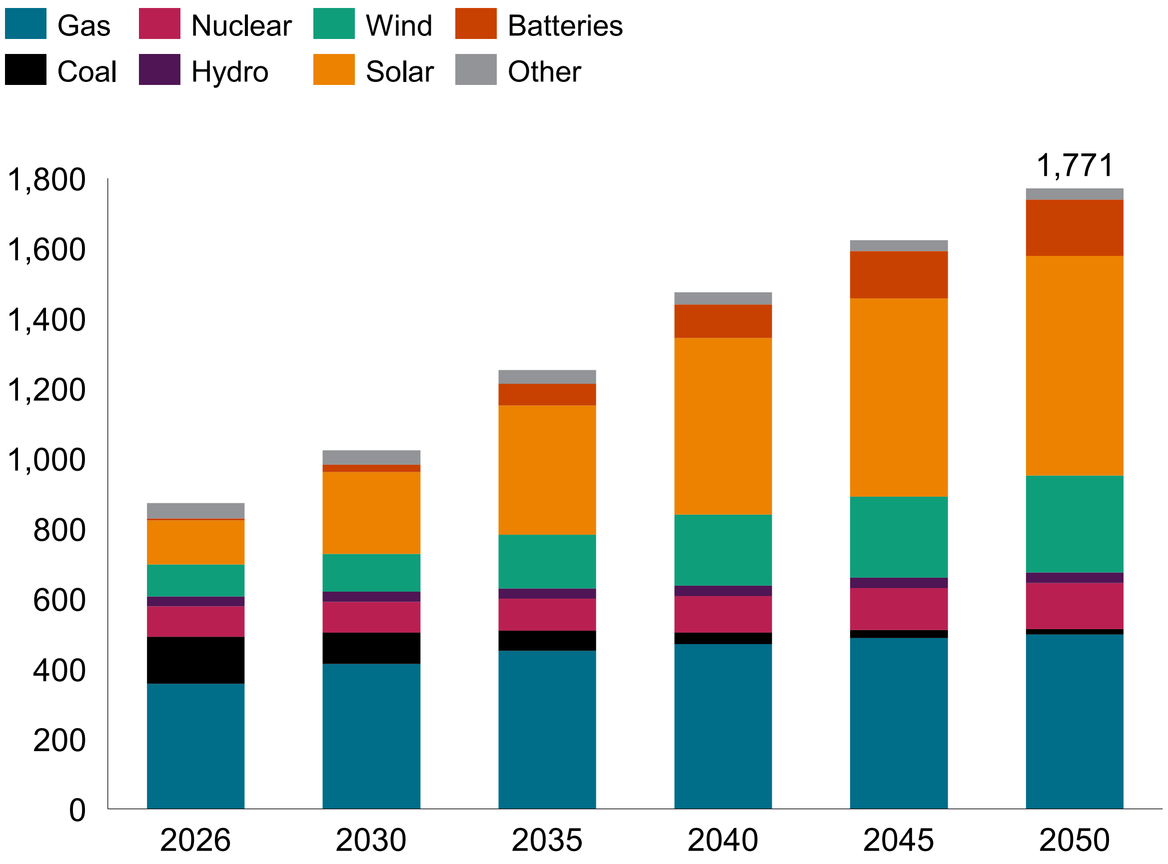
IHV Base Case

GW



High Demand Case

GW



Source: S&P Global Energy

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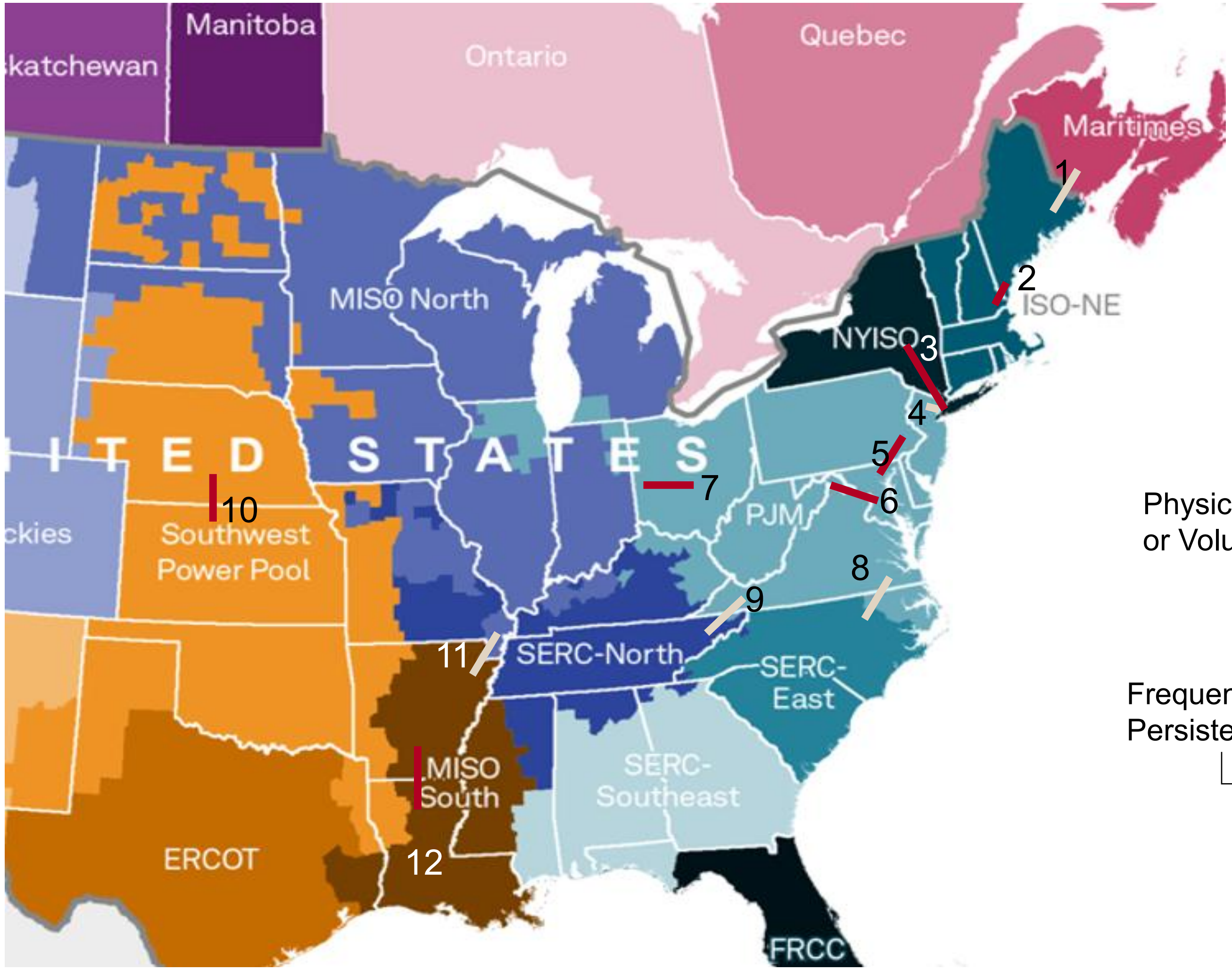
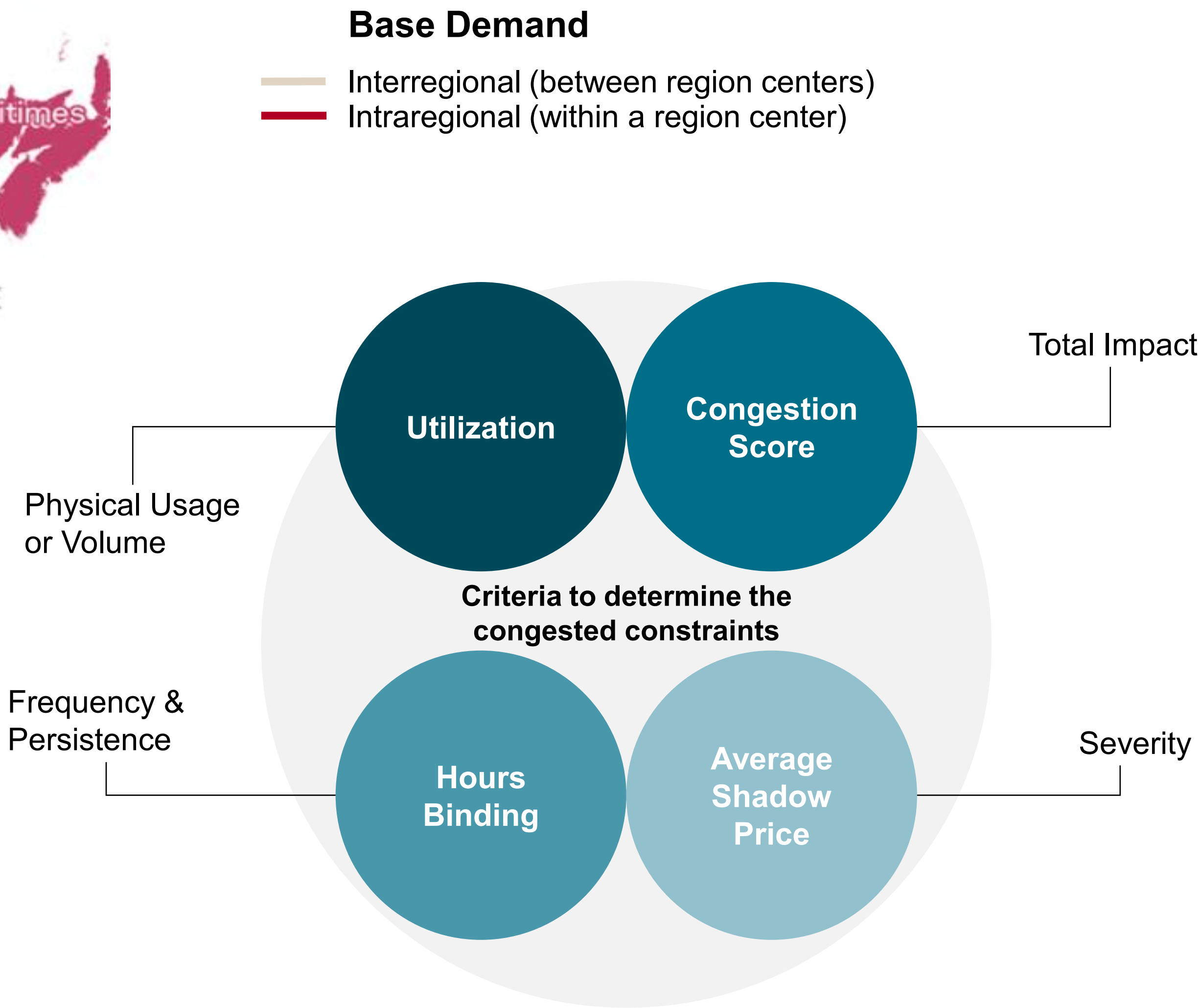
Selected transmission expansion candidates in the Base Demand case based on multiple criteria





These selected transmission projects are represented by lines on the map showing approximate locations and are not to scale. This study provides a high-level analysis and does not consider actual route information or permitting.
Source: S&P Global Energy

Spreads and congestion score determine optimal capacities across 12 interregional and intraregional transmission projects in the Base Demand case

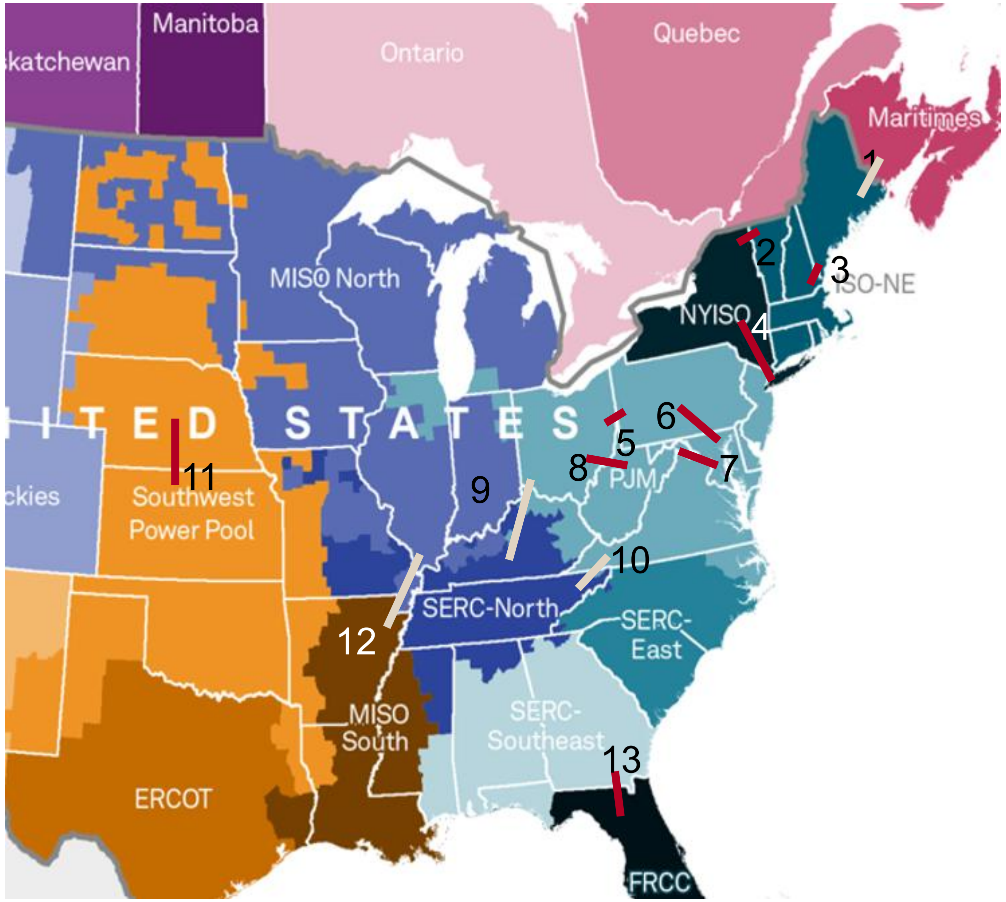
No.	Region Center	Category	Zone From	Zone To	Unconstrained (MW)	Constrained (MW)
1	ISONE + NYISO	**Inter**	ISONE Maine	Maritimes	1250	0
2	ISONE + NYISO	Intra	ISONE Maine	ISONE New Hampshire	1250	1000
3	ISONE + NYISO	Intra	NYISO Zone E Mohawk Valley	NYISO Zone J New York City	1250	1000
4	PJM	**Inter**	PJM PSEG	NYISO Zone J New York City	500	0
5	PJM	Intra	PJM BGE	PJM PECO	1250	1000
6	PJM	Intra	PJM AP	PJM PEPCO	1000	1000
7	PJM	Intra	PJM AEP	PJM Dayton	1250	1000
8	SERC + FRCC	**Inter**	PJM Dominion	SERC Vacar South	1250	0
9	SERC + FRCC	**Inter**	PJM Dominion	SERC TVA	1250	0
10	SPP + MISO S	Intra	SPP North	SPP KSMO	1250	1000
11	SPP + MISO S	**Inter**	MISO Arkansas	MISO Missouri	1250	0
12	SPP + MISO S	Intra	MISO Arkansas	MISO Louisiana	500	500

Source: S&P Global Energy

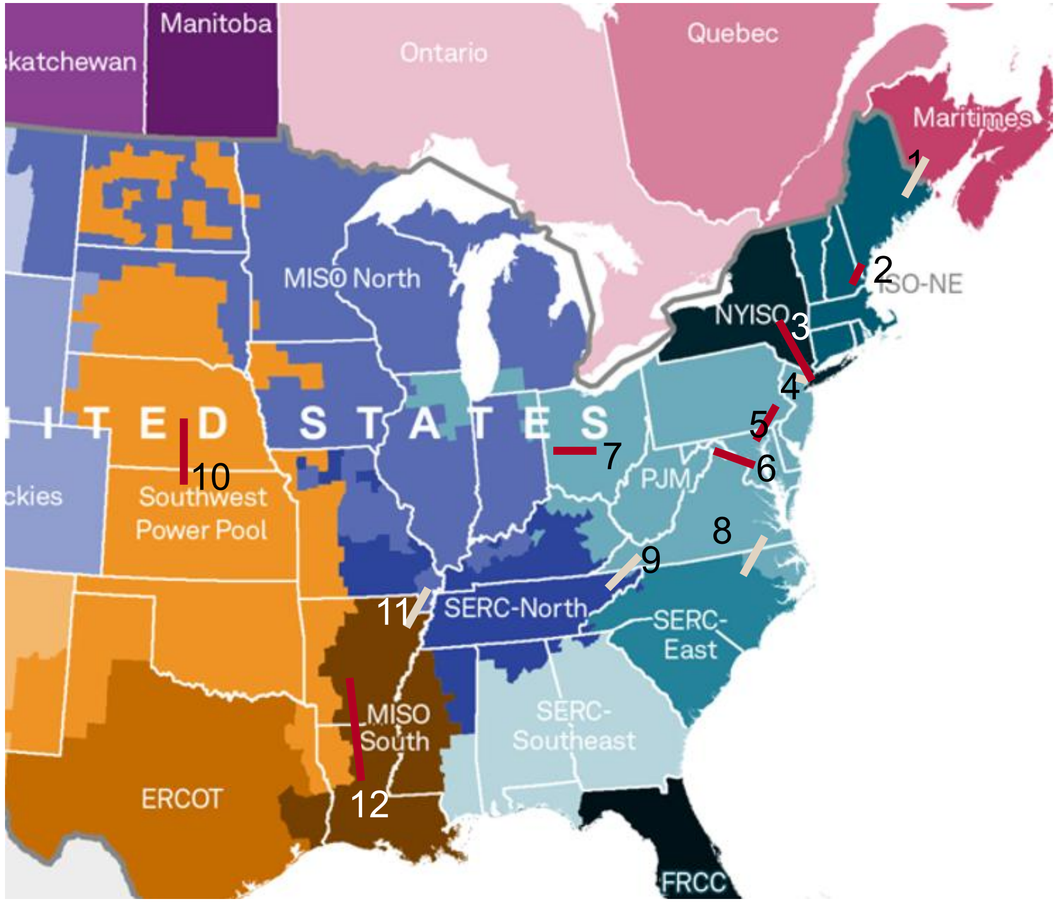
Transmission expansion projects in both cases

Interregional (between region centers) Intraregional (within a region center)

High Demand



Base Demand



These selected transmission projects are represented by lines on the map showing approximate locations and are not to scale. This study provides a high-level analysis and does not consider actual route information or permitting.

Source: S&P Global Energy

High Demand case includes 13 transmission projects with congestion patterns similar to the Base Demand case, using the same criteria for optimal sizing

No.	Region Center	Category	Zone From	Zone To	Unconstrained (MW)	Constrained (MW)
1	ISONE + NYISO	**Inter**	ISONE Maine	Maritimes	1250	0
2	ISONE + NYISO	Intra	ISONE Vermont	NYISO Zone D North	500	500
3	ISONE + NYISO	Intra	ISONE Maine	ISONE New Hampshire	1250	1000
4	ISONE + NYISO	Intra	NYISO Zone E Mohawk Valley	NYISO Zone J New York City	1250	1000
5	PJM	Intra	PJM Duquesne	PJM AEP	1250	1000
6	PJM	Intra	PJM BGE	PJM PENELEC	1250	1000
7	PJM	Intra	PJM AP	PJM PEPCO	1250	1000
8	PJM	Intra	PJM AEP	PJM AP	1250	1000
9	SERC + FRCC	**Inter**	PJM DEOK Duke Ohio Kentucky	SERC TVA	500	0
10	SERC + FRCC	**Inter**	PJM Dominion	SERC TVA	1000	0
11	SPP + MISO S	Intra	SPP North	SPP KSMO	1250	1000
12	SPP + MISO S	**Inter**	MISO Arkansas	MISO Illinois	1250	0
13	SERC + FRCC	Intra	SERC Southeast	FRCC	500	500

Source: S&P Global Energy

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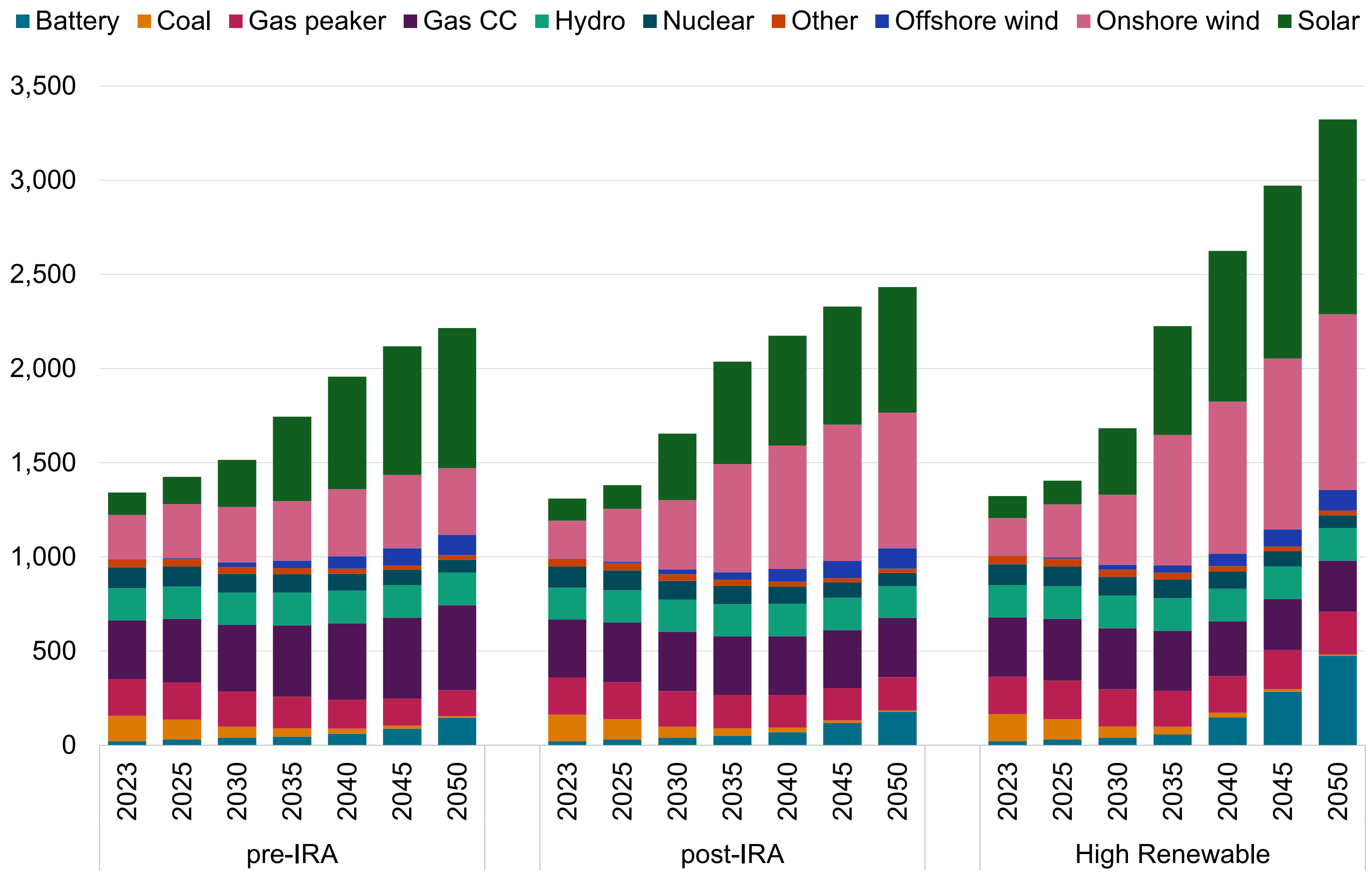
The Capacity Expansion Model identifies least-cost supply portfolios and enables scenario and sensitivity analysis across policy, cost, and demand assumptions

Illustrative electric supply portfolio comparison across scenarios

Installed capacity (GW)



Data compiled January 2026.
Source: S&P Global Energy

The Capacity Expansion Model (CEM) enables rapid and systematic scenario analysis and parameter sensitivities

- CEM is a linear programming model that optimizes investment and dispatch over a multiyear horizon to determine the least-cost supply portfolios for meeting energy and peak demand requirements subject to policy constraints
- The model uses an LDC approach with representative days or weeks to model supply and demand requirements. The LDC is complemented by an hourly chronological sub-model for tuning battery charge/discharge profiles
- A seasonal approach is utilized for understanding renewable and thermal capacity credits as well as reserve margins
- Policy constraints include state renewable portfolio standards, technology deployment targets and emissions limits, among others
- CEM relies on rich geospatially resolved datasets for renewable energy resource potential, technology costs, and fuel prices
- CEM results are complemented by the expert judgment of regional market analysts to inform the long-term North American power market outlook. CEM is particularly well suited to informing long-term market penetration estimates for renewables, optimal retirement schedules, and the sensitivity of resource build schedules to small variations in key parameters
- Common parameters selected for sensitivity analysis in CEM include gas prices, demand growth rates, demand shapes, technology costs, carbon prices, and tax credits

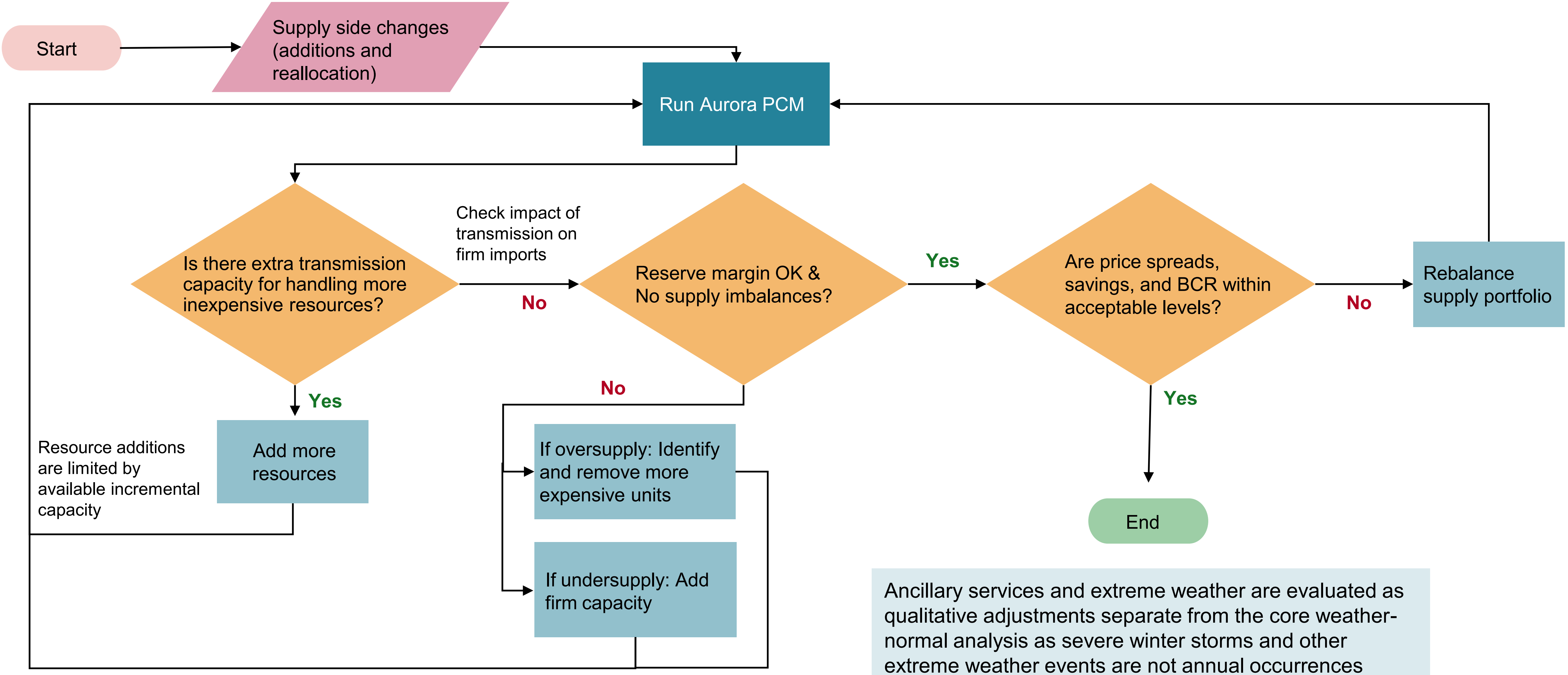
Drivers of power supply additions and retirements vary by technology, combining near-term project pipelines with policy direction, economics, and asset owner announcements

Drivers of power supply capacity changes in North American power markets (House View)

	Renewables and battery storage	Nuclear	Natural gas	Coal
	Project development pipeline in the near term, and then:			
Additions	▪ Current policies ▪ Expected policy expansion ▪ Utility/corporate targets ▪ Project economics	▪ Expect continued bipartisan support ▪ US Energy Department support for reactors and the fuel supply chain ▪ Big Tech interest	▪ Energy and capacity needs (conventional) ▪ Policy (CCS-equipped)	▪ N/A (conventional) ▪ Policy (CCS-retrofit)
	Asset owner announcements in the near term, and then:			
Retirements	▪ Retirement/repowering age (years): – Onshore wind (25) – Offshore wind (30) – Solar (30)	▪ License expiration or relicensing ▪ Continued federal and state support	▪ Projected profitability	▪ Projected profitability ▪ State policy ▪ Federal policy

Data compiled January 2026. N/A: Not Applicable.
Source: S&P Global Energy

An iterative rebalancing process identifies the transmission capacity and supply mix to optimize benefits and maintain reserve margins across the Base and High Demand cases



Ancillary services and extreme weather are evaluated as qualitative adjustments separate from the core weather-normal analysis as severe winter storms and other extreme weather events are not annual occurrences

Source: S&P Global Energy

The benefit-cost framework applies an NPV analysis that weighs the present value of system-wide and local infrastructure benefits against candidate transmission project costs

Benefits

Type of benefit	Component	Description	Sources
System-level benefit	**Avoided CAPEX**	Capital expenditures avoided by displacing generation capacity in the target regions	S&P Global estimated CAPEX
	Avoided fixed OPEX	Fixed operating costs avoided due to displaced generation capacity in the target regions	S&P Global estimated OPEX
	Adjusted production costs savings	Savings in total system variable costs captured through production cost modeling	Production cost modeling
Local infrastructure benefits	**Avoided transmission**	Potential savings from avoiding the need for transmission reinforcements Proposed transmission projects will increase the system reliability, which would offset future routine maintenance, congestion mitigation measures, or the need to replace lower kV lines	ISO RTEP

Costs

Component	Description	Sources
CAPEX	Capital expenditures for TX project	ISO RTEP
Fixed OPEX	Fixed operating and maintenance costs for TX project	ISO RTEP

The high-level "Net Benefit" is evaluated using a discounted NPV approach (PV benefit minus PV cost), where the present value is calculated over a 40-year transmission economic lifetime using a discount rate

Source: S&P Global Energy

Contents

Transmission expansion in the benefit-cost analysis assumes 345 kV interzonal lines, with costs informed by ISO planning studies

Transmission network expansion assumptions

345 kV single-circuit AC lines between adjacent zones or states

100 to 200 miles

500 to 1250 MW

Data sources for transmission costs

Category	Source
1 ISO	PJM: RTEP 2025, Transmission Cost Planner MISO: Transmission Cost Estimation Guide ERCOT: 2024 RTP
2 Existing Studies	DOE: NTPS NREL: ReEDS
3 Others	EIA, FERC

We prioritized recent sources, including PJM and MISO, for our high-level transmission line cost estimates. These sources offer detailed coverage of most states included in the region centers

Source: S&P Global Energy, ISOs, RTEP

EPA (2025 update) and S&P Global's financial assumptions for discount rates, inflation, and capital charge rates are used to annualize and discount future benefits and costs

			Item	Values	Economic life	Reference
	Inflation and Discounting	Determines how future benefits and costs are valued at Present Value (2024$)	Discount rate, real	3.76%		EPA Reference Case
			Inflation	2.3%		S&P Global
	Capital Charge Rate (CCR), real	Capital charge rates are used to annualize capital costs over the asset's life. This allows for apples-to-apples comparison of annualized costs across different technologies and business models	BESS	12.13%	20	EPA Reference Case
			Gas	10.19%	30	EPA Reference Case
			Onshore Wind	9.23%	30	EPA Reference Case, NREL (Cost of Wind Energy Review 2024)
			Grid Facing Solar PV	9.23%	30	EPA Reference Case
			Transmission line	11.79%	40	S&P Global

Transmission FOM approximated as 1% of upfront CAPEX per year.
Source: S&P Global Energy, EPA: Documentation for EPA's Power Sector Modeling Platform 2023, EPA 2025 Reference Case

Clarifying key assumptions and critical metrics

Modeling Assumptions

- **High level analysis**
- **Zonal production cost modeling and not actual route information and permitting**
- **All selected transmission projects are 345 kV single-circuit lines and come online by 2035**
- **All gas capacity displacement is realized directly in 2035**
- **Zero line losses and no line outages**

Definitions

Adjusted Production Cost (APC): Production Cost (Fuel Cost + Emission Cost + VOM Cost + Startup Cost) + Net Imports

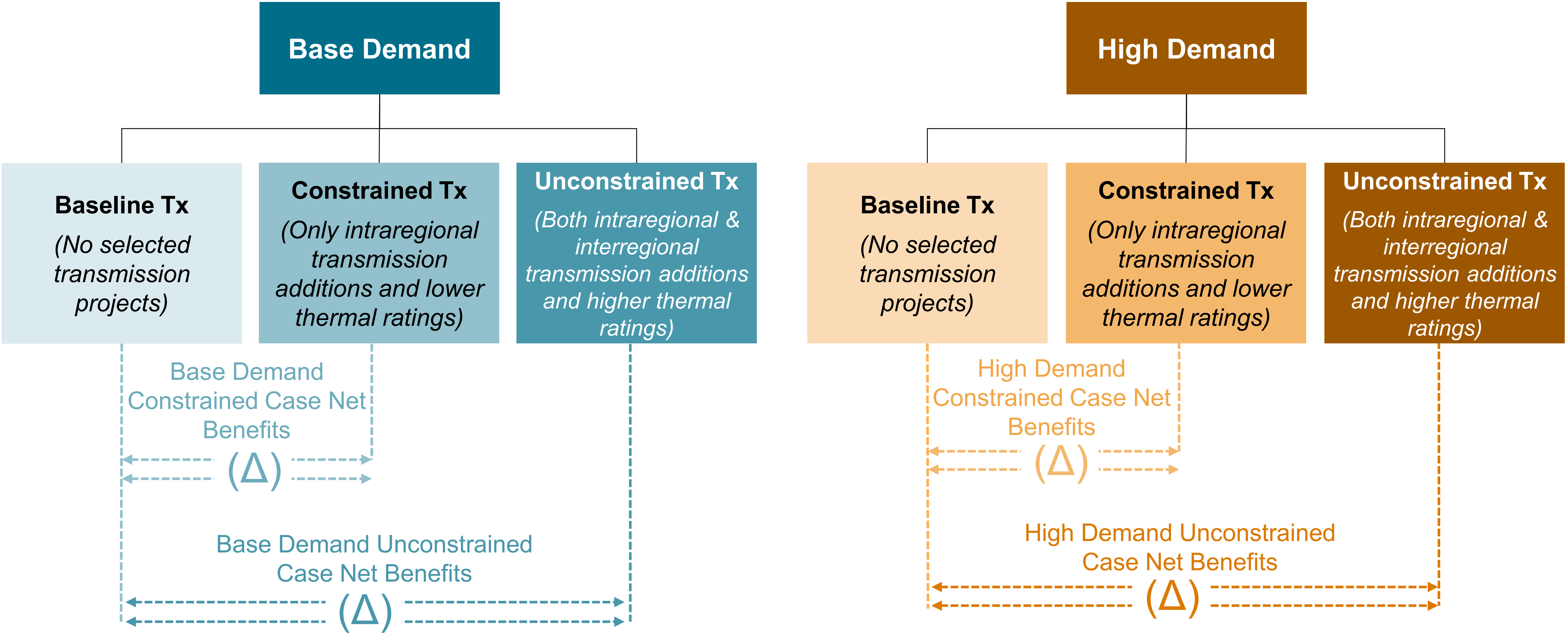
Net Present Value (NPV): Present Value of Total Benefits *(Production Cost Savings + Avoided Transmission Costs + Avoided Δ Gen CAPEX + FOM)* – Present Value of Total Costs *(Transmission Additions CAPEX and FOM)*

Benefit-Cost Ratio: Present Value of Total Benefits / Present Value of Total Costs

Emissions savings: Primarily based on CO2 cost reductions calculated by multiplying displaced CO2 emissions by the Regional Greenhouse Gas Initiative (RGGI) allowance price

Source: S&P Global Energy

The Benefit-Cost Assessment calculates value of transmission projects by comparing Constrained and Unconstrained transmission scenarios against a no new build Baseline



Source: S&P Global Energy

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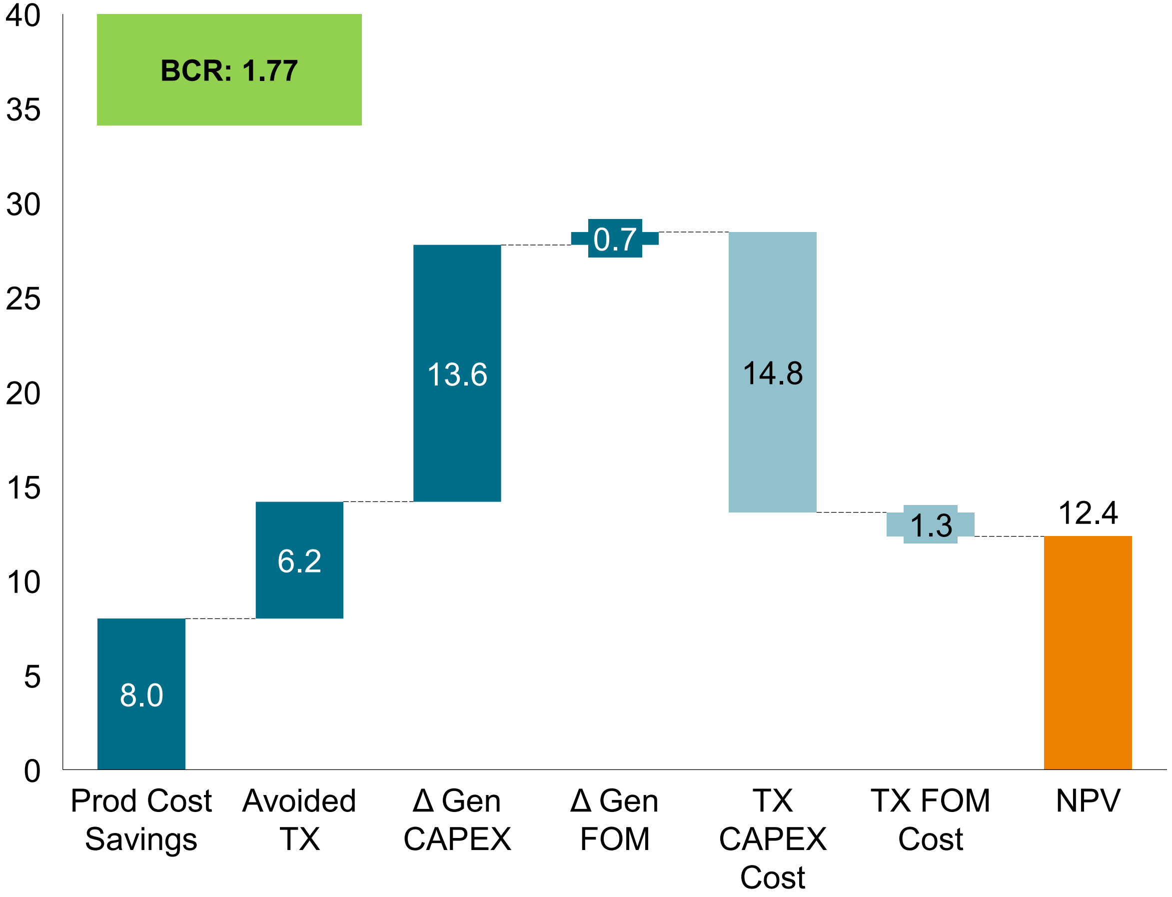
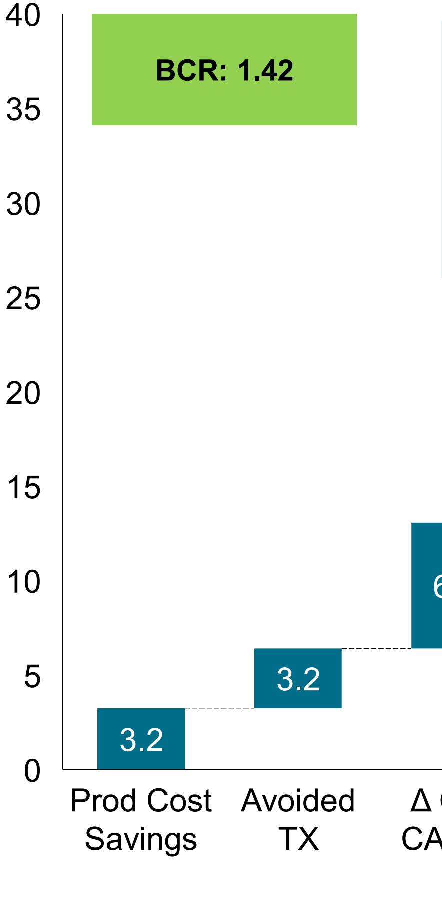
Across the full EIC footprint, the Unconstrained Base Demand case delivers ~$12.4B of NPV at a 1.77 BCR, three times the constrained case's ~$4B NPV and 1.42 BCR

Present Value Waterfall in the Base Demand Case ($ Billions real 2024)

Unconstrained Case



Constrained Case



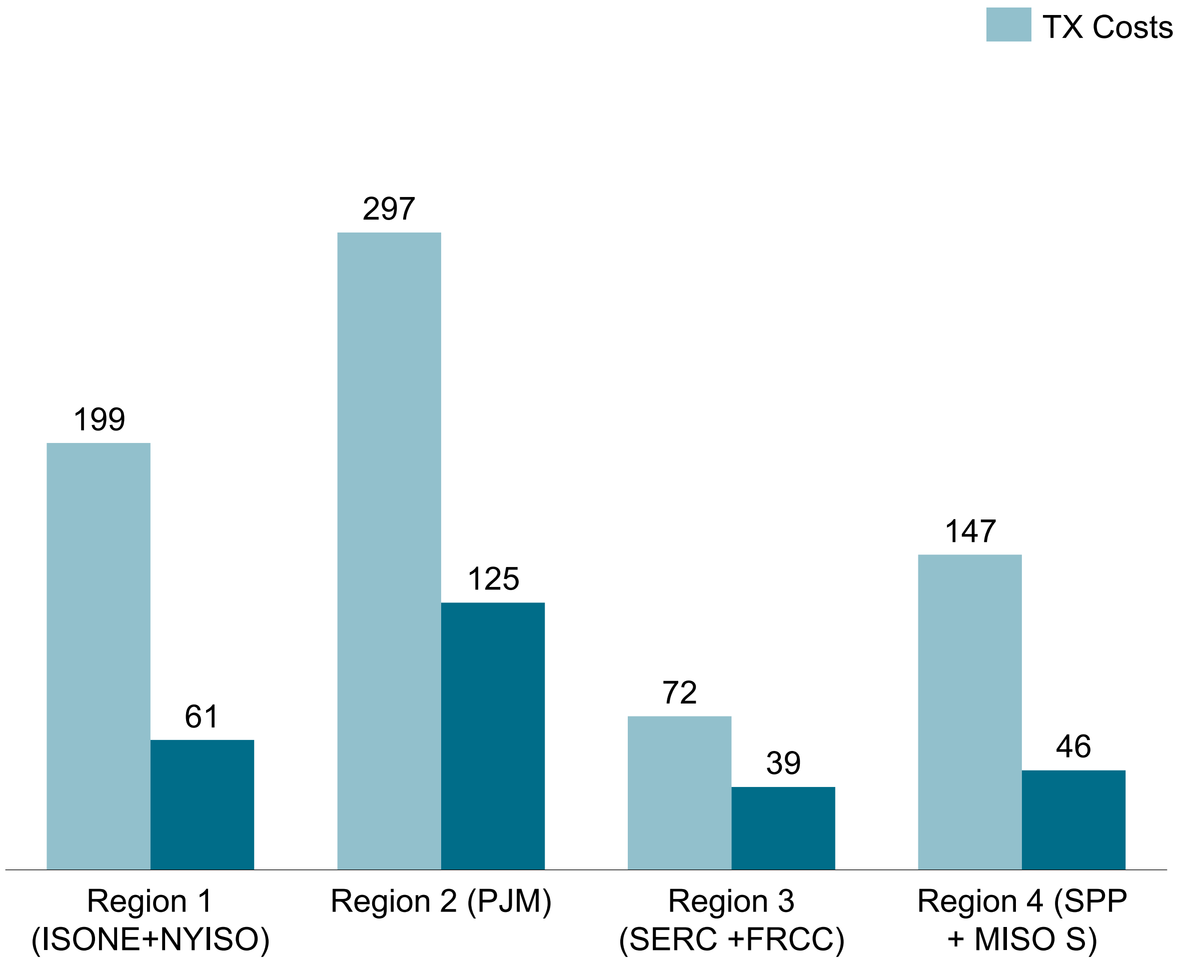
The biggest contributor to NPV is **Δ Gen CAPEX**, followed by production cost savings and avoided transmission costs, as transmission expansion enables access to lower-cost remote resources, reducing the need for more expensive local generation builds

BCR (Benefit-Cost Ratio) = Present Value of Total Benefits (Production Cost Savings + Avoided Transmission Costs + Avoided Δ Gen CAPEX/CCR + FOM) / Present Value of Total Costs (Transmission Addition CAPEX and FOM).
NPV = Present Value of Total Benefits – Present Value of Total Costs.
Source: S&P Global Energy

Transmission mainly reduces the need for reliability and maintenance driven local upgrades and lower voltage lines rather than replacing local utility rebuilds or competing projects

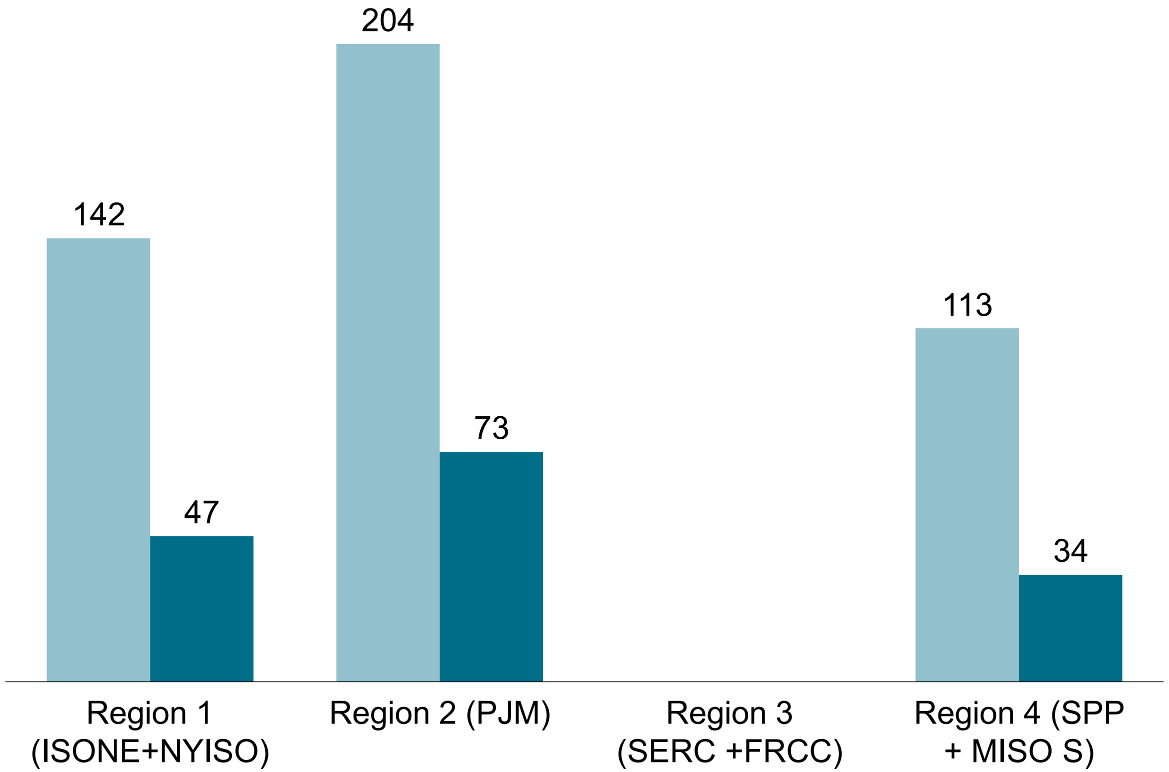
Annual Transmission Costs and Avoided Transmission Benefits in the Base Demand Case ($ Millions real 2024)

Unconstrained Case



Constrained Case

The Selected transmission expansion candidates in the SERC region are interregional transmission projects that are not allowed in the Constrained case

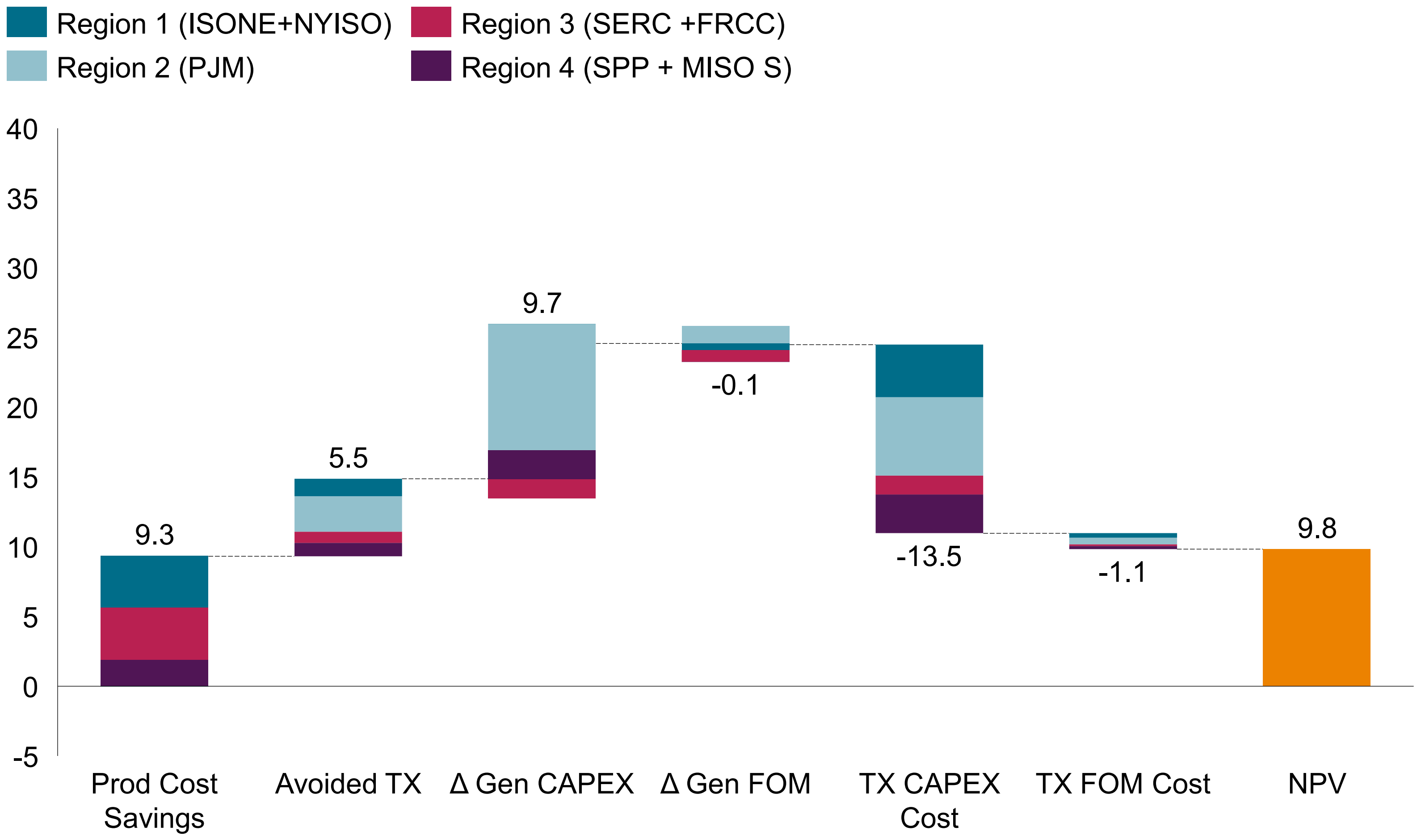


Source: S&P Global Energy and RTEP

PJM accounts for the bulk of value in the Unconstrained Base Demand case since it has the largest share of selected transmission projects

Present Value Waterfall in the Unconstrained Base Demand Case, by Region Centers

$ Billions real 2024



No.	Region Center	PV Total Benefits $B real 2024	PV Costs $B real 2024	BCR
1	ISONE + NYISO	4.48	4.08	**1.10**
2	PJM	12.81	6.10	**2.10**
3	SERC + FRCC	2.32	1.47	**1.58**
4	SPP + MISO S	4.89	3.01	**1.62**

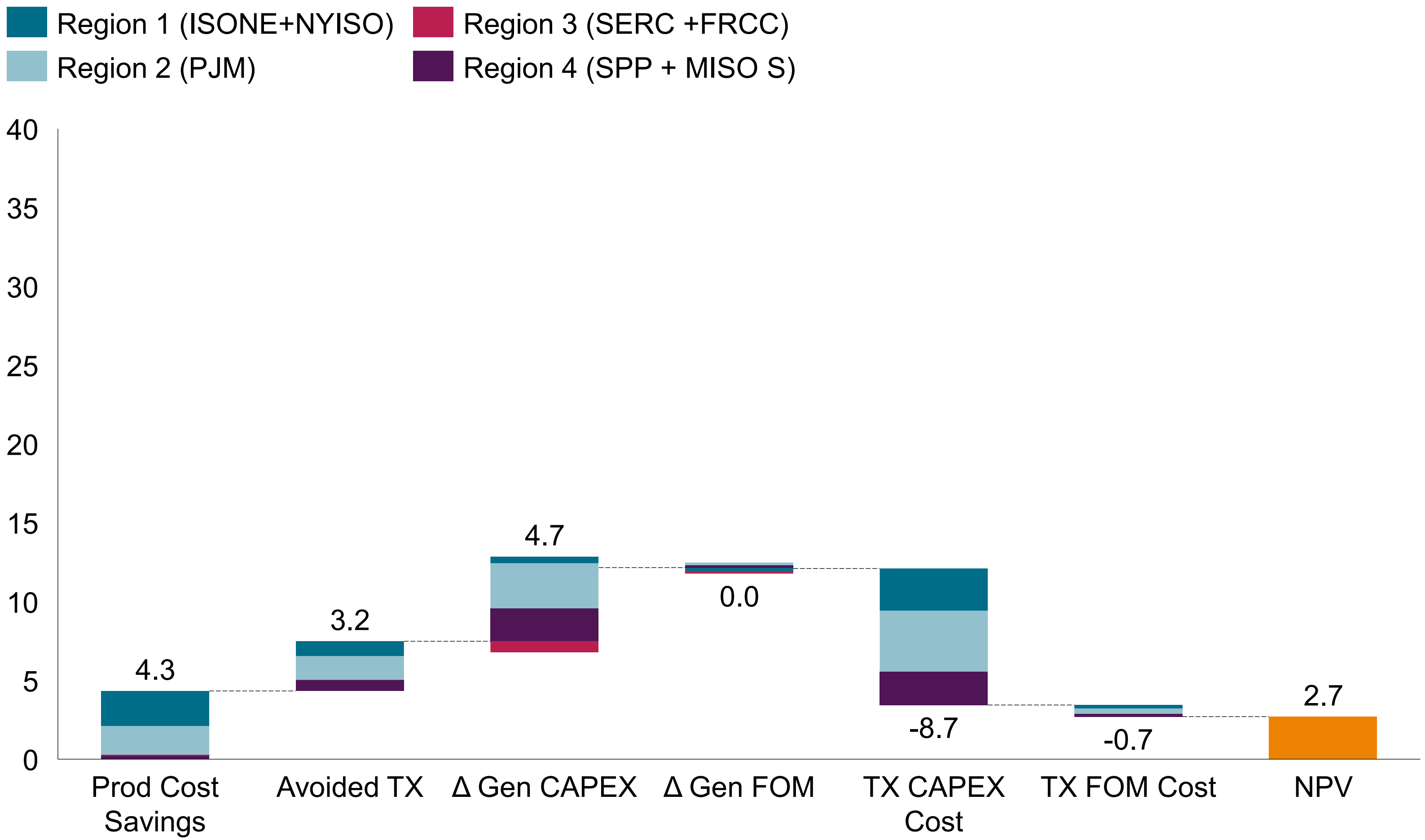
PJM generates most of the $9.8B in NPV by maximizing additional transmission, both intraregional and interregional. From a defense standpoint, robust transmission expansion, especially interregional in heavily datacenter concentrated areas like PJM, is essential to ensure the Defense Industrial Base (DIB) has reliable, uninterrupted power to maintain manufacturing readiness

Source: S&P Global Energy

PJM still leads in the Constrained Base Demand case, but the lack of interregional transmission reduces regional benefits and lowers the BCRs

Present Value Waterfall in the Constrained Base Demand Case, by Region Centers

$ Billions real 2024



No.	Region Center	PV Total Benefits $B real 2024	PV Costs $B real 2024	BCR
1	ISONE + NYISO	3.37	2.91	**1.16**
2	PJM	6.35	4.18	**1.52**
3	SERC + FRCC[1]	NA	NA	NA
4	SPP + MISO S	3.16	2.32	**1.36**

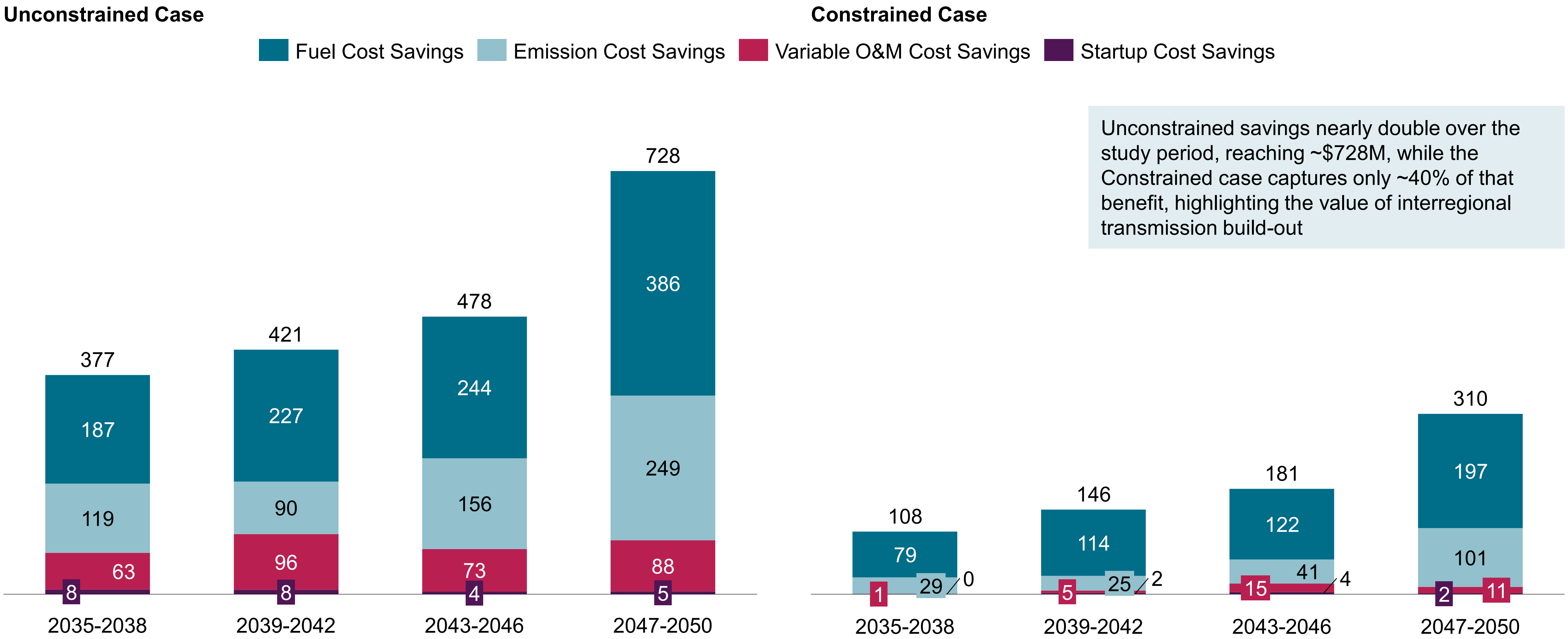
The lack of interregional transmission cuts the overall NPV to $2.7B, and SERC including FRCC is affected the most because intraregional projects are not considered and the interregional ties are also disabled in the constrained case. This pattern can create a national security vulnerability: without interregional and intraregional ties or expanded transmission, military installations lack the redundant grid support needed to withstand prolonged localized outages

1. The Selected transmission expansion candidates in the SERC region are interregional transmission that are not allowed in the Constrained case.

Source: S&P Global Energy

EIC production cost savings from the proposed transmission projects grow over time in the Base Demand case, with fuel and emission costs driving ~85% of the total

Breakdown of Annual Production Cost Savings[1] in the Base Demand Case ($ Millions nominal)



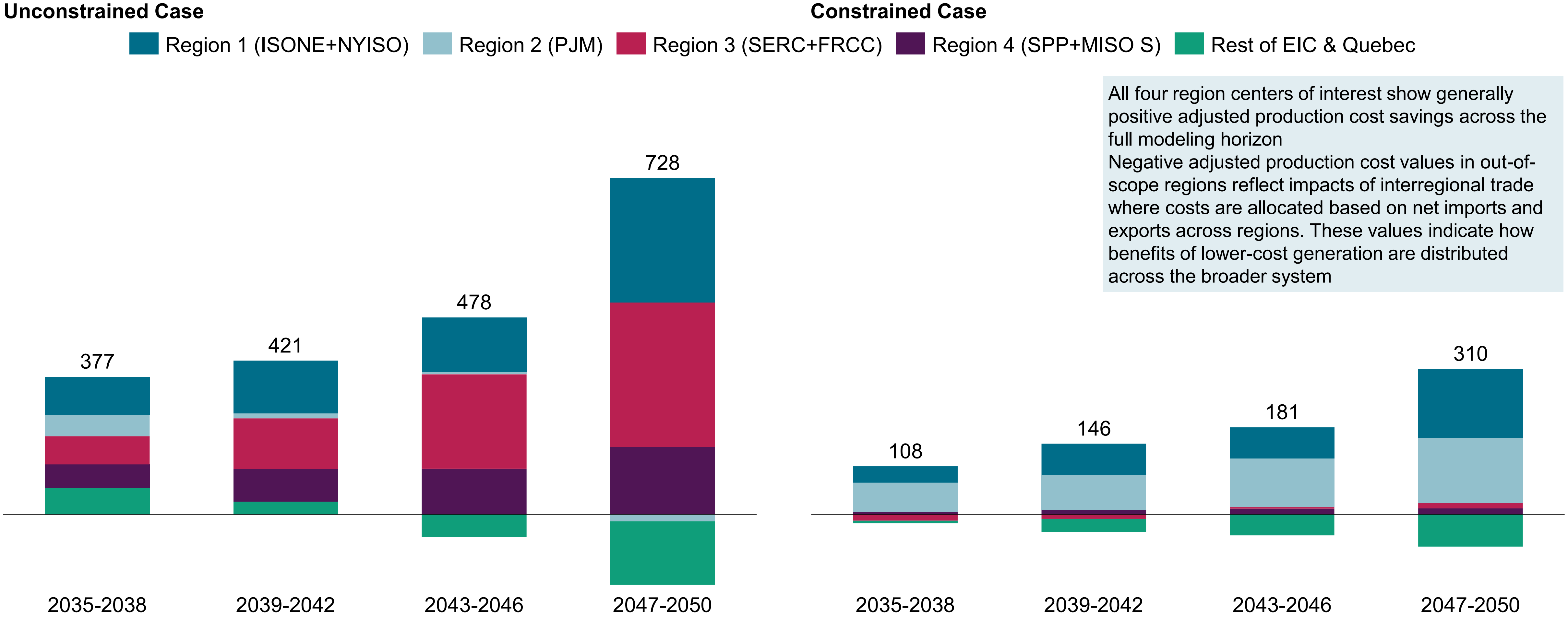
Unconstrained savings nearly double over the study period, reaching ~$728M, while the Constrained case captures only ~40% of that benefit, highlighting the value of interregional transmission build-out

1. The savings are calculated as the baseline case minus the change case (baseline: no selected transmission projects; change: with the proposed selected transmission projects, including both Constrained and Unconstrained cases).

Source: S&P Global Energy

Higher transmission limits and interregional transmission projects change import and export patterns, which are the main reasons for differences in the adjusted production cost results

Adjusted Production Savings in the Base Demand Case, by Region Centers ($ Millions nominal)



All four region centers of interest show generally positive adjusted production cost savings across the full modeling horizon

Negative adjusted production cost values in out-of-scope regions reflect impacts of interregional trade where costs are allocated based on net imports and exports across regions. These values indicate how benefits of lower-cost generation are distributed across the broader system

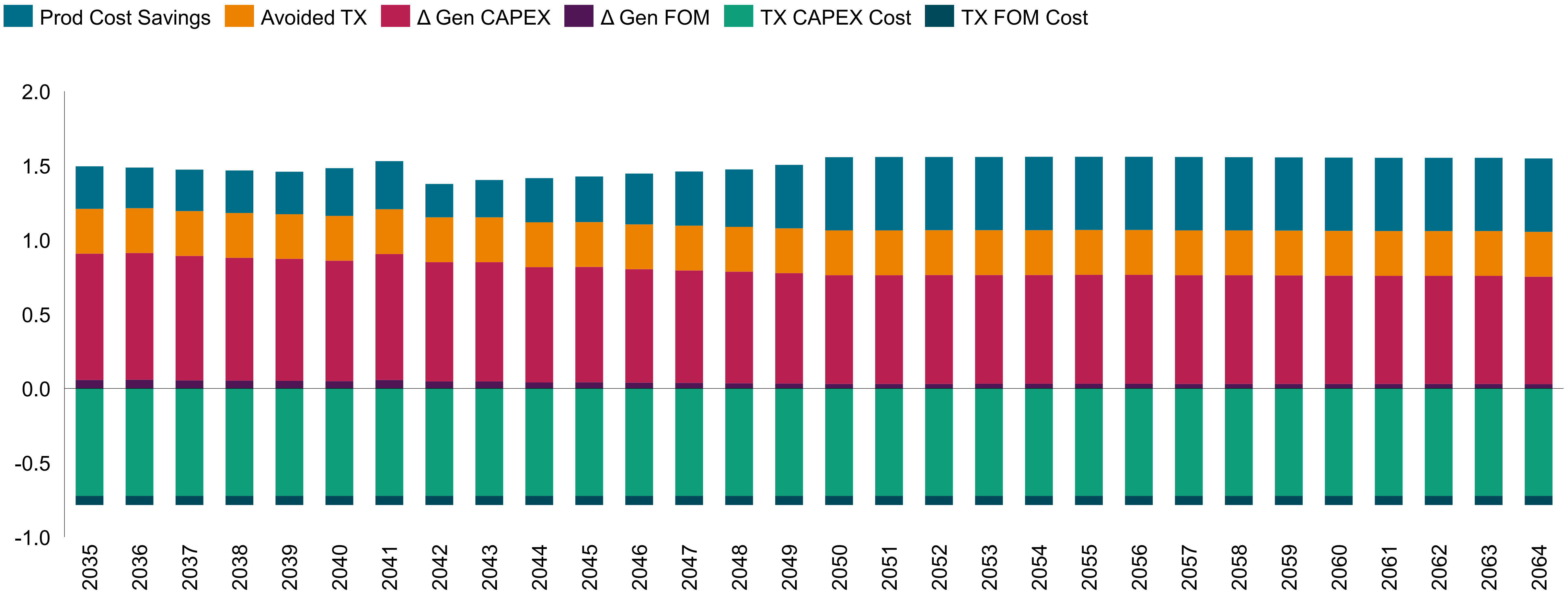
APC: Adjusted Production Costs. The negative APC values for PJM in 2047–2050 reflect the treatment of net imports in the adjusted production cost metric. During these years, PJM becomes a net importer, and because the metric includes the cost of net imports, higher net import volumes increase PJM's APC relative to the baseline case.

Source: S&P Global Energy

Across the first 30 years through 2064, annual benefits in the Unconstrained Base Demand case run roughly double annual costs, producing stable net positive results

Annual Benefits and Costs in the Base Demand Case ($ Billions real 2024)

Unconstrained Case

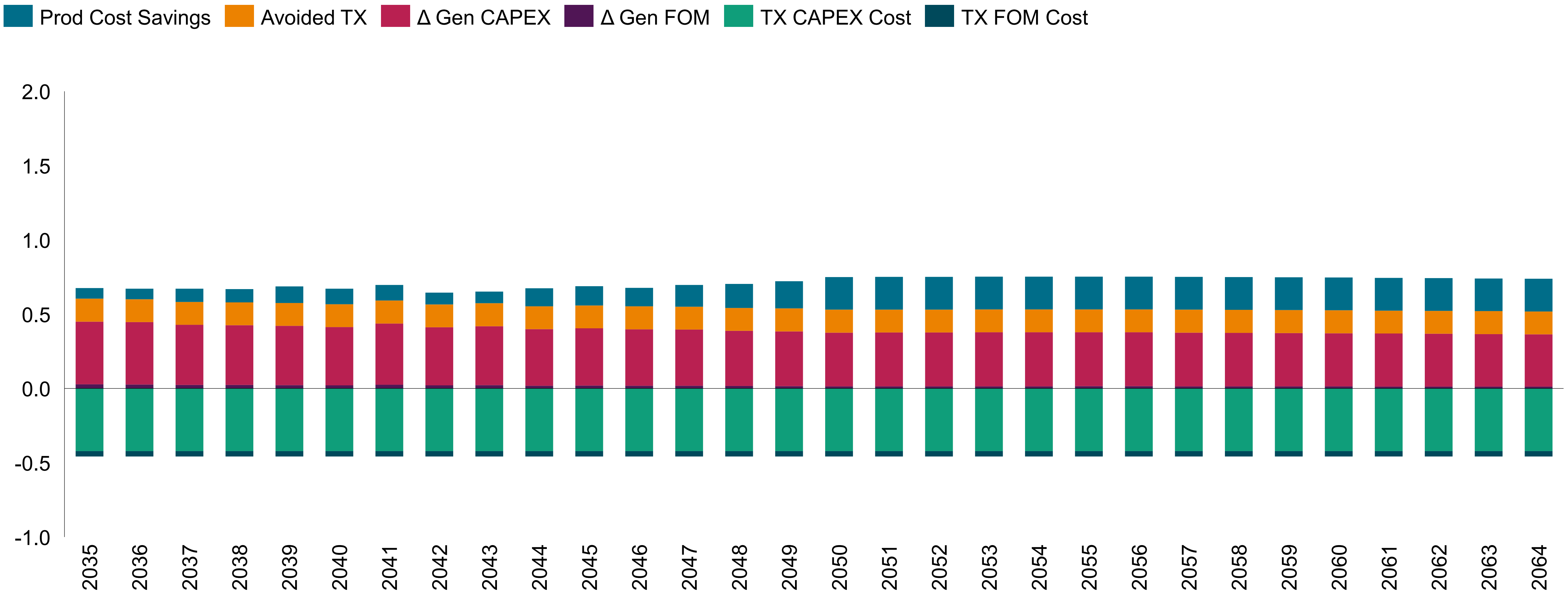


Source: S&P Global Energy

Reduced transmission expansion in the Constrained case cuts annual benefits roughly in half (~$700M vs $1.5B) but still produces positive net annual value through 2064

Annual Benefits and Costs in the Base Demand Case ($ Billions real 2024)

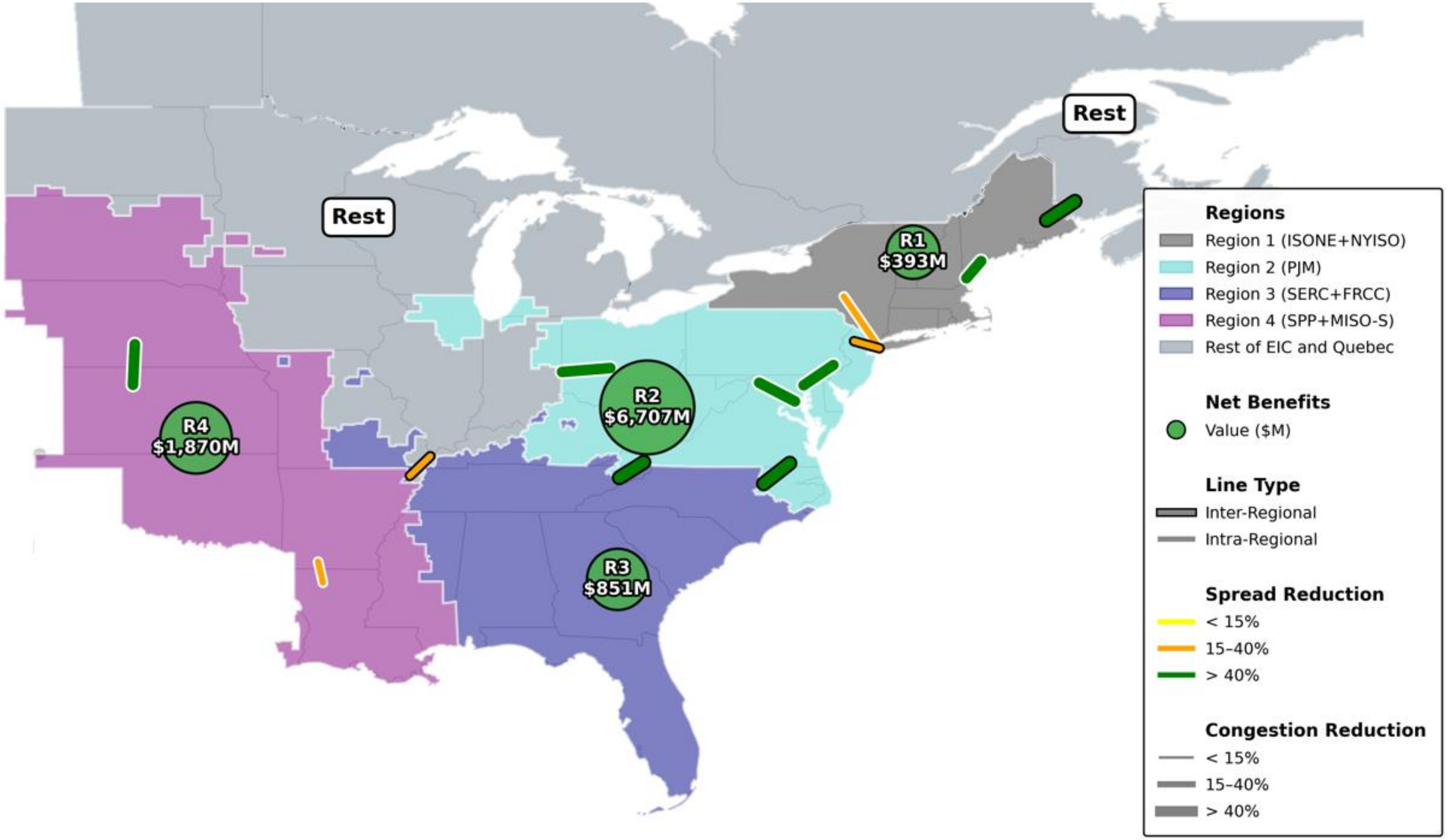
Constrained Case



Source: S&P Global Energy

Interregional transmission in the Unconstrained Base Demand Case pushes the highest Net Benefits into PJM with stronger spread and congestion relief than the Constrained case

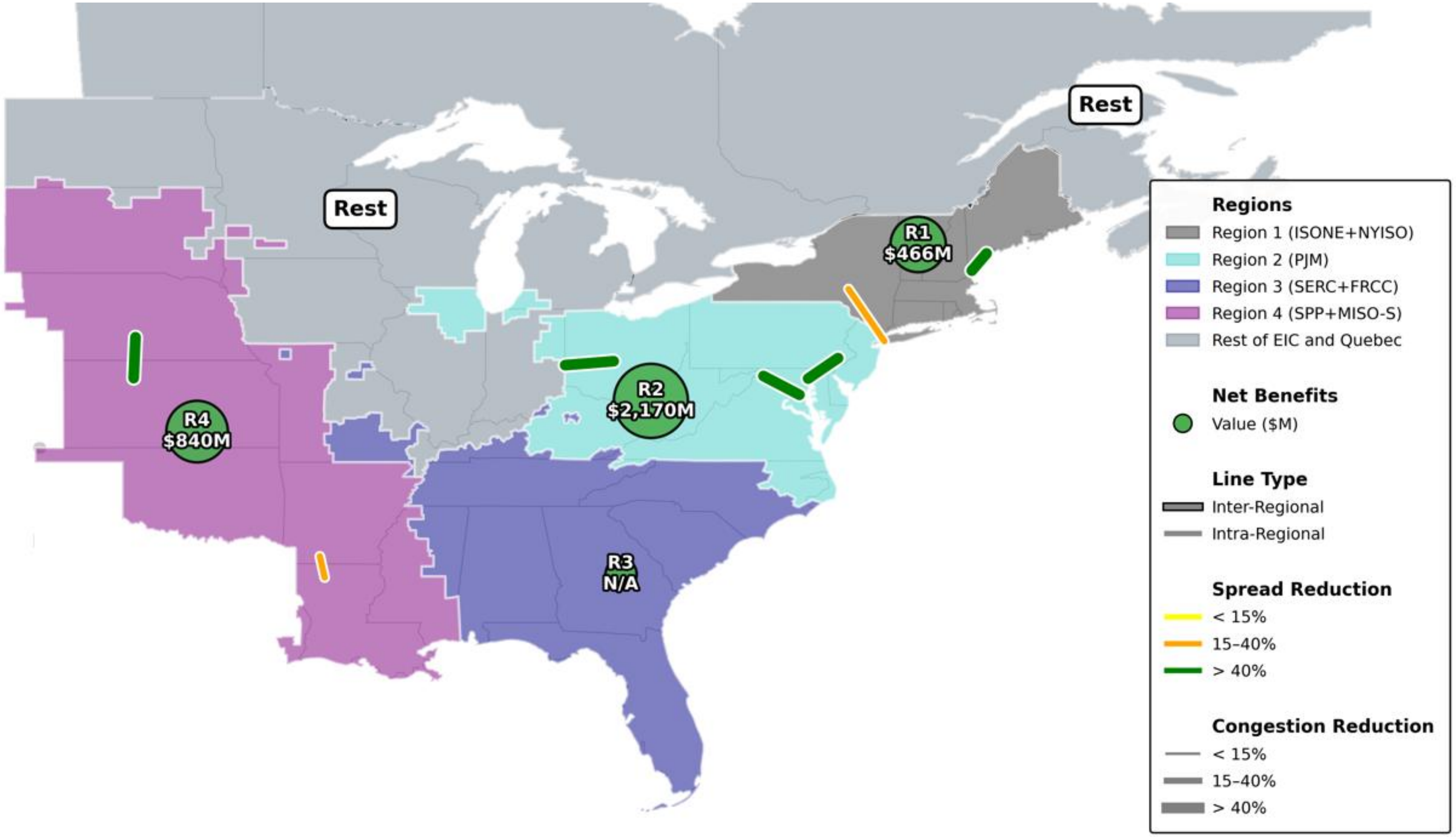
Transmission Impact Analysis in the Unconstrained Base Demand Case



The net benefits reflect the full horizon (over a 40-year transmission economic lifetime), while the spread and congestion reduction is for the initial year 2035, by when all the selected transmission expansion come online.
These selected transmission are represented by lines on the map showing approximate locations and are not to scale. This study provides a high-level analysis and does not consider actual route information or permitting.
Source: S&P Global Energy

Base demand under Constrained transmission additions sees Region 2 and 4 with the highest Net Benefits and strongest spread and congestion relief

Transmission Impact Analysis in the Constrained Base Demand Case



The net benefits reflect the full horizon (over a 40-year transmission economic lifetime), while the spread and congestion reduction is for the initial year 2035, by when all the selected transmission expansion come online. These selected transmission are represented by lines on the map showing approximate locations and are not to scale. This study provides a high-level analysis and does not consider actual route information or permitting.
Source: S&P Global Energy

The retail rate savings are positive in Base Demand case due to transmission expansion projects, with PJM offering higher retail rate savings, followed by the Northeast region

This analysis is weather-normalized and does not capture additional benefits associated with extreme weather performance or ancillary services, which could further increase retail rate savings. As expected, the Unconstrained case shows higher retail rate savings than the Constrained case, largely due to the added value of interregional transmission expansion. Although the selected transmission projects produce benefit-cost ratios above 1.0, the estimated retail rate savings are relatively modest because the projects under study are small in scale relative to the size of the system, causing their benefits to be spread over a broad load base

Unconstrained Base Demand Case

No.	Region Center	2035 Annual Benefits ($M nominal)	2035 Annual Wholesale Demand (GWh)	2035 Annual Savings Benefits/ Demand (cents per kWh)	2050 Annual Benefits ($M nominal)	2050 Annual Wholesale Demand (GWh)	2050 Annual Savings Benefits/ Demand (cents per kWh)
1	ISONE + NYISO	120	302,805	0.0396	87	382,942	0.0228
2	PJM	307	1,032,497	0.0297	861	1,205,175	0.0714
3	SERC + FRCC	206	1,130,171	0.0183	18	1,334,086	0.0014
4	SPP + MISO S	134	600,671	0.0222	200	722,372	0.0277

Constrained Base Demand Case

No.	Region Center	2035 Annual Benefits ($M nominal)	2035 Annual Wholesale Demand (GWh)	2035 Annual Savings Benefits/ Demand (cents per kWh)	2050 Annual Benefits ($M nominal)	2050 Annual Wholesale Demand (GWh)	2050 Annual Savings Benefits/ Demand (cents per kWh)
1	ISONE + NYISO	42	302,805	0.0140	107	382,942	0.0279
2	PJM	154	1,032,497	0.0149	258	1,205,175	0.0214
3	SERC + FRCC	NA	1,130,171	NA	NA	1,334,086	NA
4	SPP + MISO S	69	600,671	0.0115	105	722,372	0.0145

SERC region doesn't have any transmission expansion projects in the Constrained Base Demand case because the only transmission projects in SERC are interregional and are not allowed in the constrained case.
Source: S&P Global Energy

Deploying Advanced Transmission Technologies can yield significant system-wide benefits that will likely offset higher initial costs, potentially resulting in improved BCRs

Definition

Advanced Transmission Technologies (ATTs) are hardware, software, and operational technologies that increase the usable transfer capability of the transmission system without building an equivalent amount of conventional new AC line. ATTs include Grid Enhancing Technologies (GETs) such as Dynamic Line Rating (DLR), Advanced Power Flow Control (APFC), and high performance conductors (ACCC/ACSS/ACCR), as well as superconducting cables

Higher line utilization (10–40% capacity uplift for GETs, ~2× for advanced conductors) and **higher effective capacity/ transfer capacity** so lines can have higher capacity with the same distance in short smaller CAPEX premium relative to larger capacity gain

Lower line losses (advanced conductors reduce I^2R losses by 30–40%), our zonal model assumes zero losses, so this benefit is not directly captured but is a real world upside

Faster deployment (GETs: 6–18 months vs. 8–15 years for new lines)

ATTs rapidly secure power grid, ensuring the reliable energy capacity required for defense industrial readiness and continuous critical military operations

Benefit and Cost Implications of ATTs

Adjusted Production Cost Savings

Higher effective transfer capacity which means more low cost generation dispatched across zones that means deeper APC savings, especially during congested/peak hours

Avoided Generation CAPEX

Higher line utilization enables more shared reserves and resource pooling across zones which means less need for peaking/local capacity builds

Avoided Transmission (Offset)

ATTs on existing corridors can defer or eliminate parallel new build/ similar/ competing projects which means direct transmission CAPEX offset

Transmission Investment Cost

More expensive ~1.5× baseline

Benefit-Cost Ratio (BCR)

Benefits are likely to offset the higher cost of ATTs that may result in higher BCR compared to baseline

Source: S&P Global Energy, U.S. DOE

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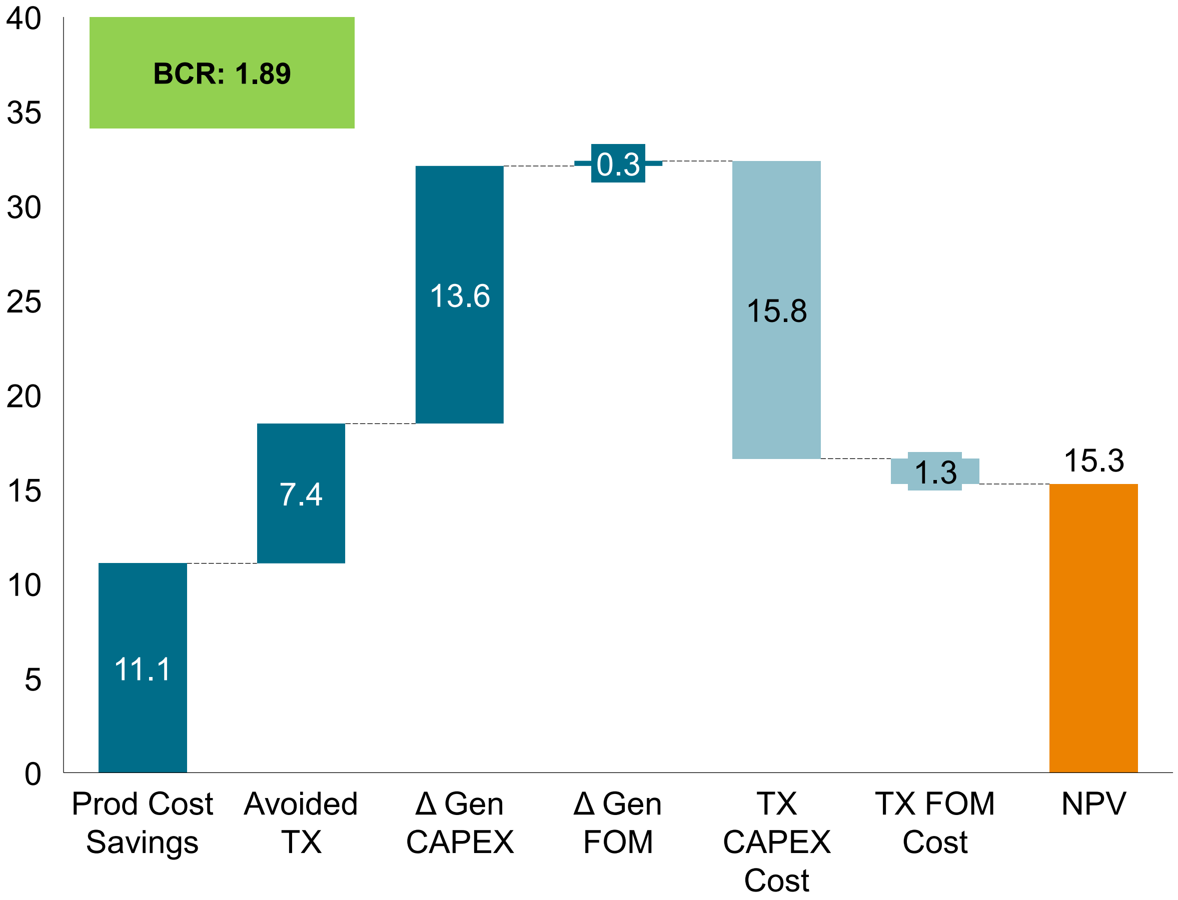
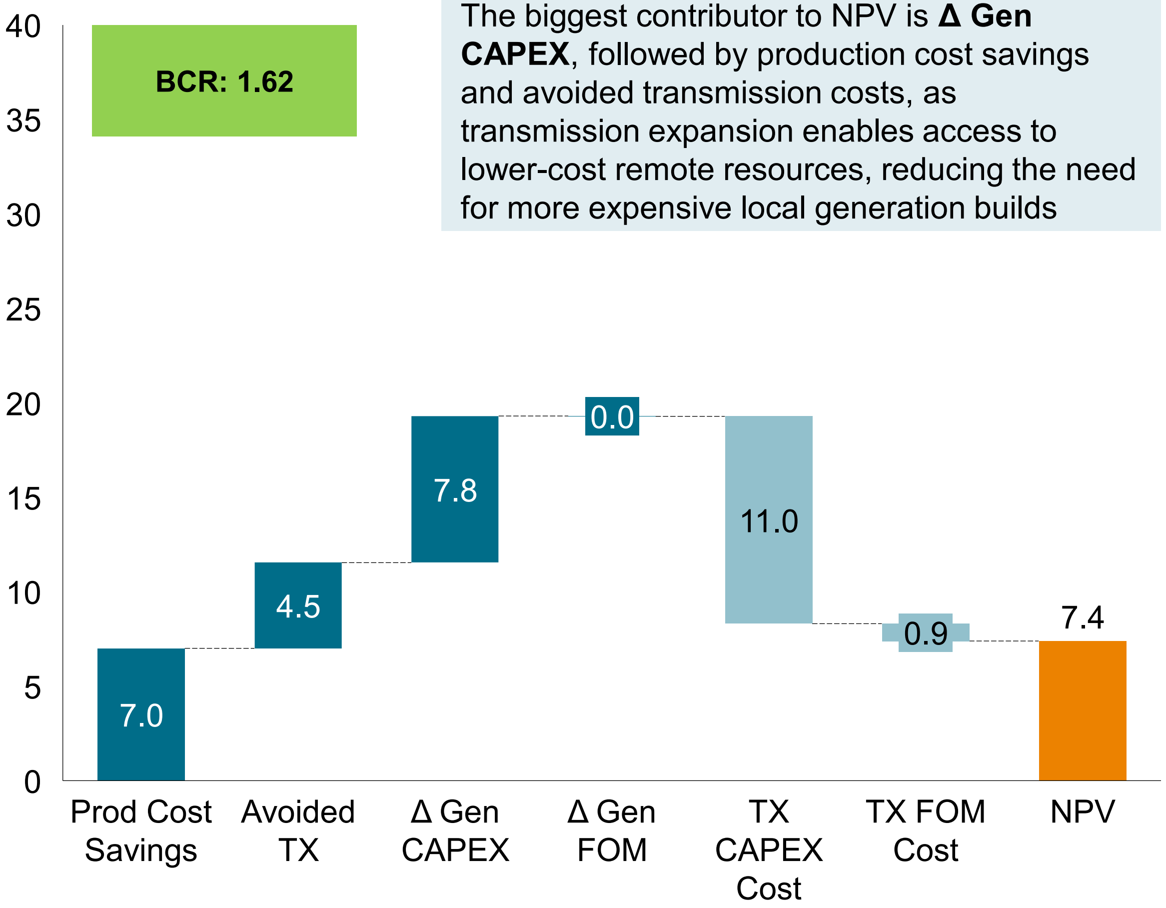
The High Demand case delivers higher benefits than the Base Demand case, following the same pattern in which the Unconstrained outperforms the Constrained by more than 2x

Present Value Waterfall in the High Demand Case ($ Billions real 2024)

Unconstrained Case



Constrained Case

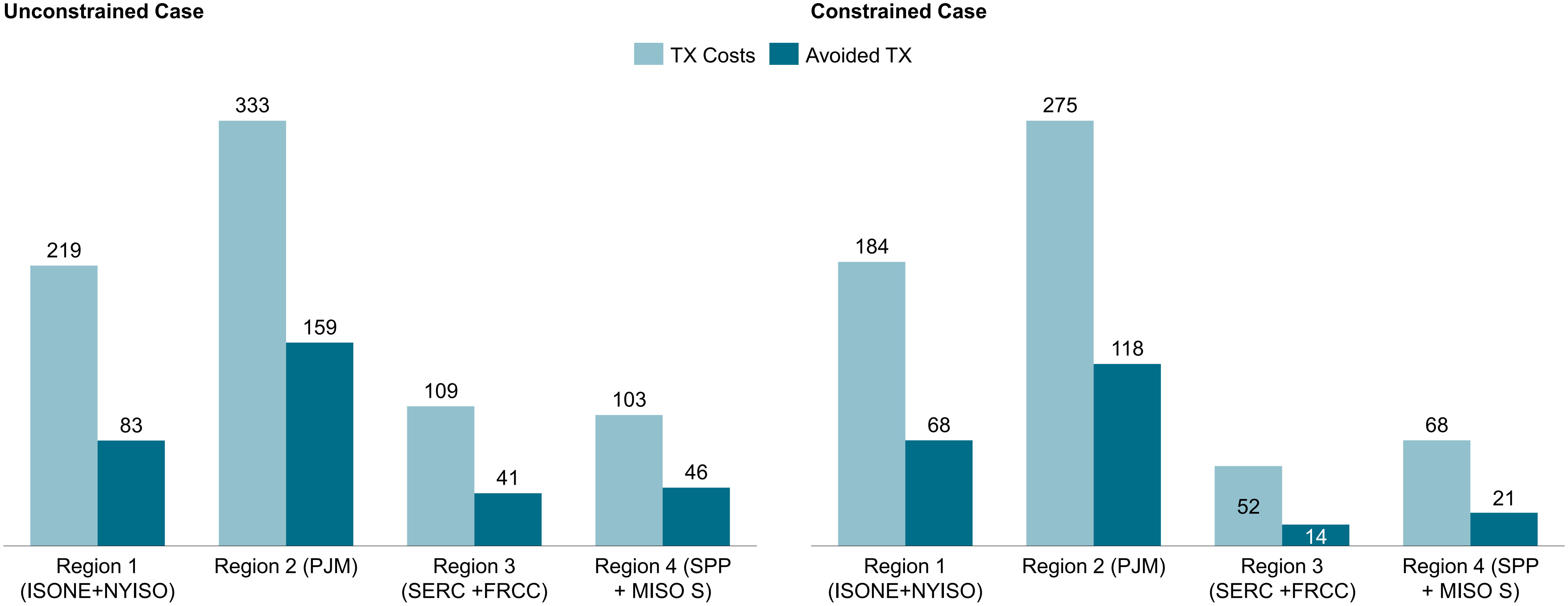


The biggest contributor to NPV is **Δ Gen CAPEX**, followed by production cost savings and avoided transmission costs, as transmission expansion enables access to lower-cost remote resources, reducing the need for more expensive local generation builds

BCR (Benefit to Cost Ratio) = Present Value of Total Benefits (Production Cost Savings + Avoided Transmission Costs + Avoided Δ Gen CAPEX/CCR + FOM) / Present Value of Total Costs (Transmission Addition CAPEX and FOM).
NPV = Present Value of Total Benefits – Present Value of Total Costs.
Source: S&P Global Energy

The same assumption holds in the High Demand case, where transmission reduces local upgrades and offsets are generally higher compared to the Base Demand case

Annual Transmission Costs and Avoided Transmission Benefits in High Demand Case ($ Millions real 2024)

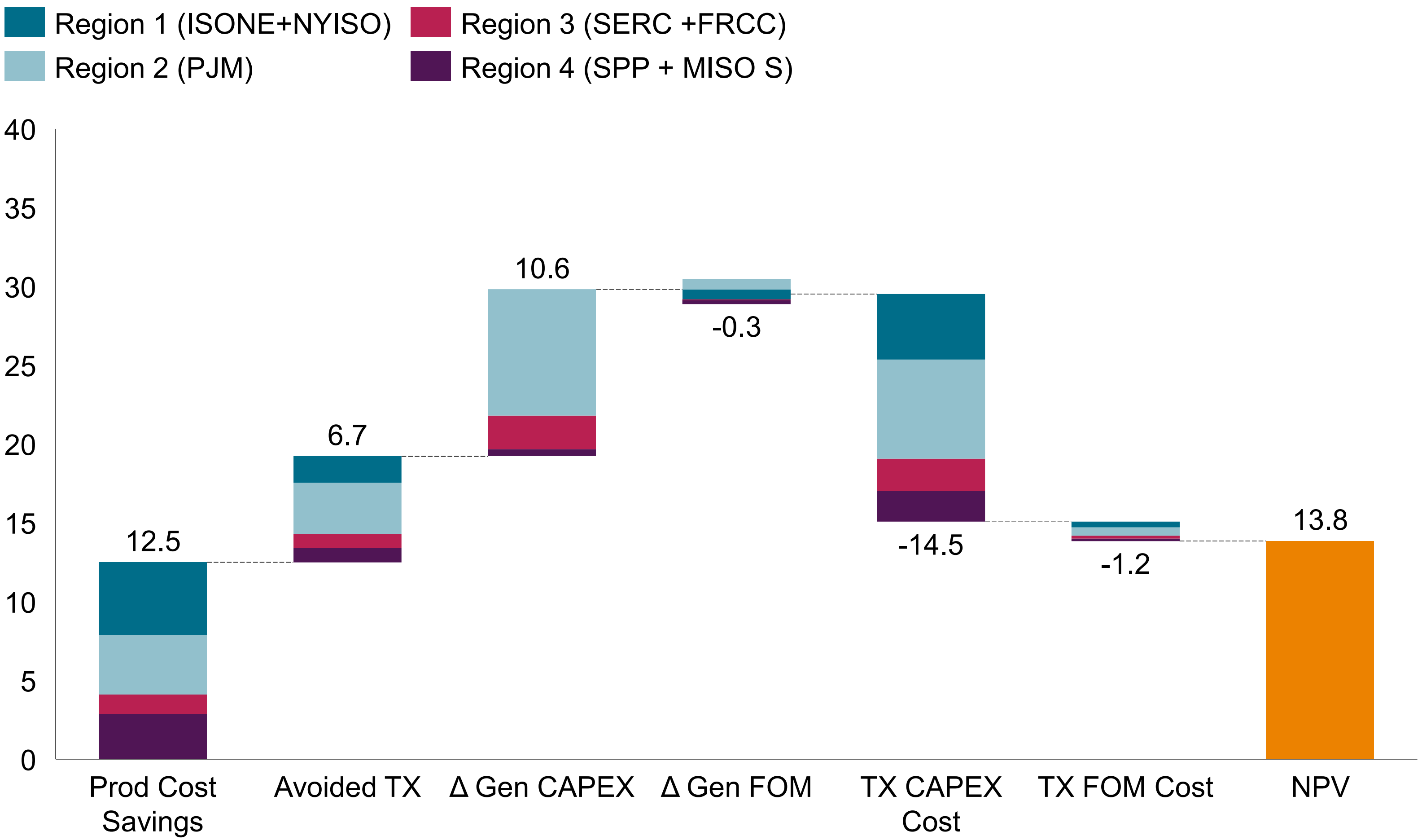


Source: S&P Global Energy

PJM drives most of the value in the Unconstrained High Demand case, consistent with the Base Demand case, because it has the largest share of selected transmission projects

Present Value Waterfall in the Unconstrained High Demand Case, by Region Centers

$ Billions real 2024



No.	Region Center	PV Total Benefits $B real 2024	PV Costs $B real 2024	BCR
1	ISONE + NYISO	5.68	4.50	**1.26**
2	PJM	15.69	6.83	**2.30**
3	SERC + FRCC	4.13	2.24	**1.84**
4	SPP + MISO S	4.02	2.10	**1.91**

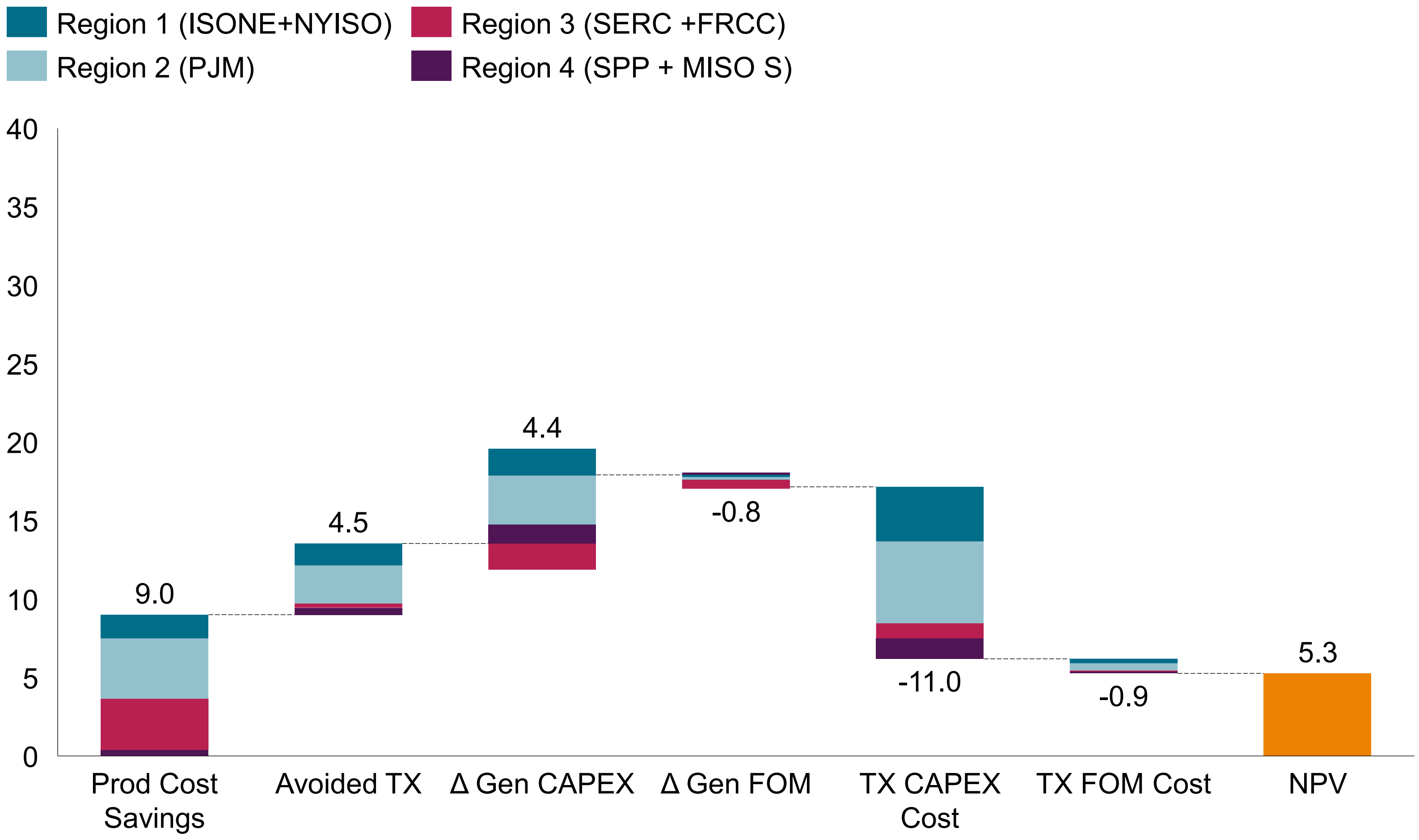
Unconstrained transmission under high demand unlocks the highest system value across all four cases, $13.8B NPV, through massive production cost savings. Strategically, increased transmission, especially interregional projects, alongside surging demand (and supply) ensures that energy intensive defense advancements and critical missions can operate without compromising the stability of interdependent civilian communities

Source: S&P Global Energy

Region 2 PJM still leads in the Constrained High Demand case, followed by Region 4, but the lack of interregional transmission reduces regional benefits and lowers the BCRs

Present Value Waterfall in the Constrained High Demand Case, by Region Centers

$ Billions real 2024



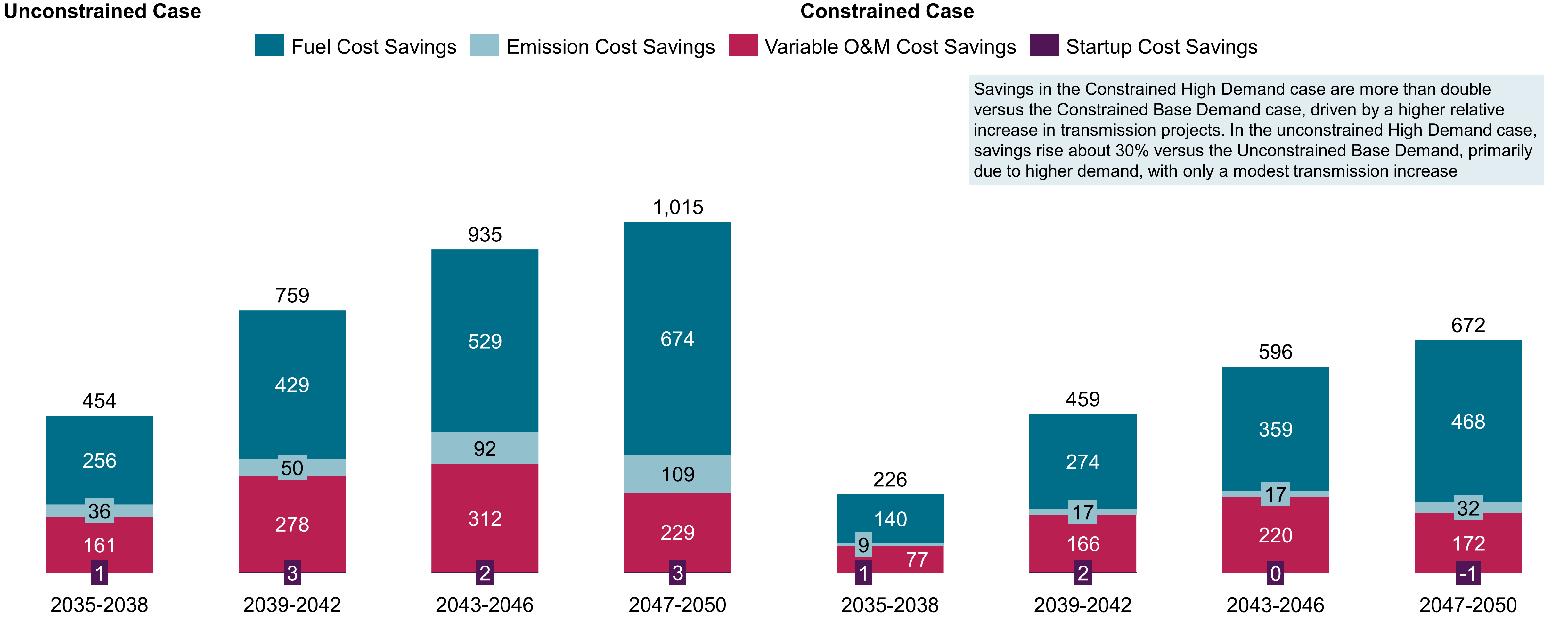
No.	Region Center	PV Total Benefits $B real 2024	PV Costs $B real 2024	BCR
1	ISONE + NYISO	4.48	3.78	**1.19**
2	PJM	9.24	5.65	**1.63**
3	SERC + FRCC	1.29	1.06	**1.21**
4	SPP + MISO S	2.15	1.40	**1.54**

Transmission constraints throttle the potential benefits, but the constrained high demand case still produces twice the overall NPV compared to the constrained base demand due to significantly higher production cost savings and avoided transmission benefits. At the same time, transmission bottlenecks, limited interregional ties, and rapidly growing demand can intensify the competition for power in some regions, which may create risks for defense manufacturing timelines and increasing the risk of cascading failures. Even so, conditions remain better than in the baseline case, where selected transmission candidates are not considered

Source: S&P Global Energy

Compared to the Base Demand case, the High Demand case delivers higher savings in both the Constrained and Unconstrained scenarios

Breakdown of Annual Production Cost Savings[1] in the High Demand Case ($ Millions nominal)



Savings in the Constrained High Demand case are more than double versus the Constrained Base Demand case, driven by a higher relative increase in transmission projects. In the unconstrained High Demand case, savings rise about 30% versus the Unconstrained Base Demand, primarily due to higher demand, with only a modest transmission increase

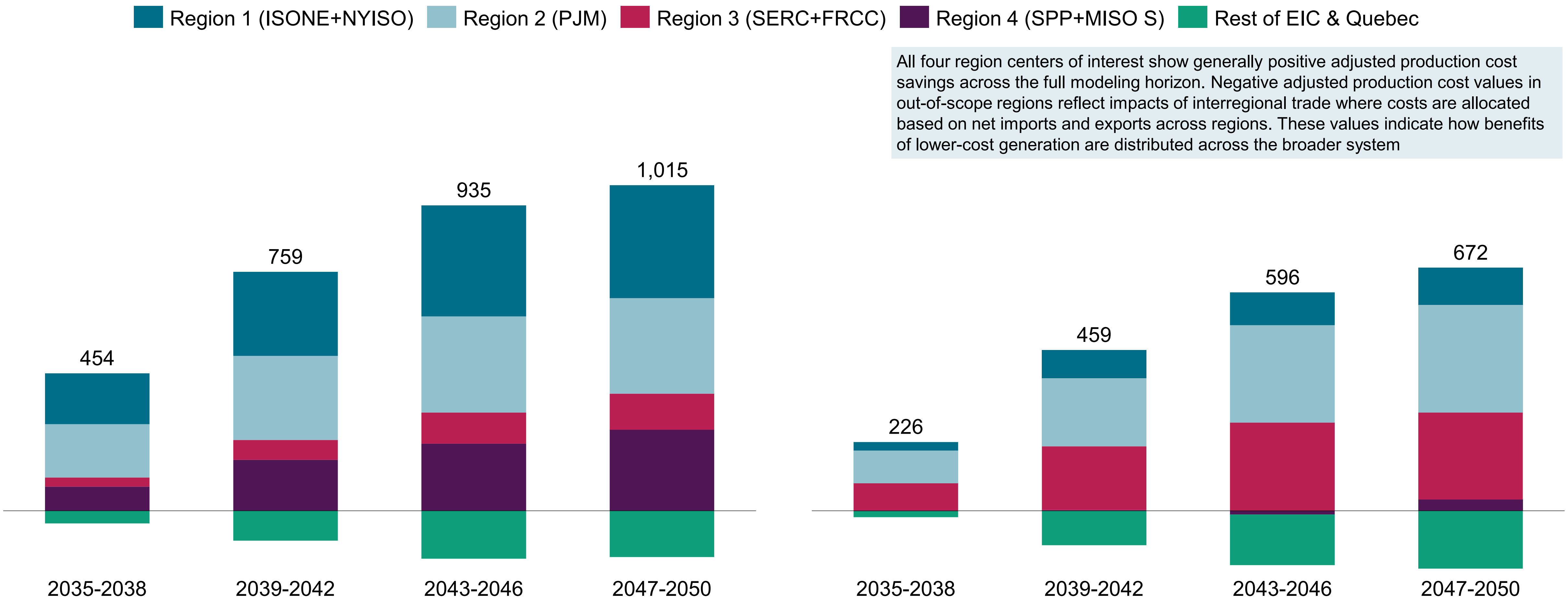
1. The savings are calculated as the baseline case minus the change case (baseline: no selected transmission projects; change: with the proposed selected transmission projects, including both Constrained and Unconstrained cases).

Source: S&P Global Energy

High demand amplifies the effect of transmission expansion, with changing import/export patterns remaining the main source of adjusted production cost differences

Adjusted Production Savings in the High Demand Case, by Region Centers ($ Millions nominal)

Unconstrained Case **Constrained Case**



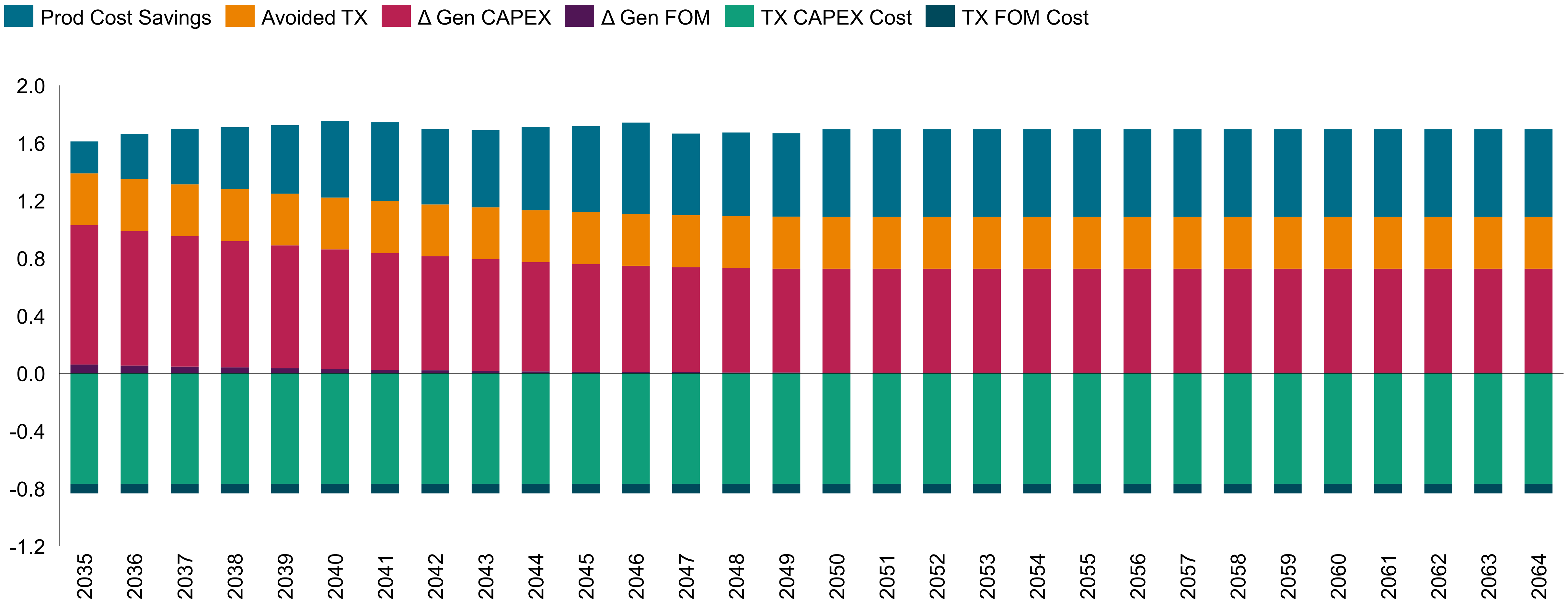
All four region centers of interest show generally positive adjusted production cost savings across the full modeling horizon. Negative adjusted production cost values in out-of-scope regions reflect impacts of interregional trade where costs are allocated based on net imports and exports across regions. These values indicate how benefits of lower-cost generation are distributed across the broader system

APC: Adjusted Production Costs.
Source: S&P Global Energy

Similar to the Base Demand case, the Unconstrained High Demand scenario doubles benefits versus costs, yielding net positive results; benefits rise to ~ $1.7B vs ~ $1.5B

Annual Benefits and Costs ($ Billions real 2024)

Unconstrained Case

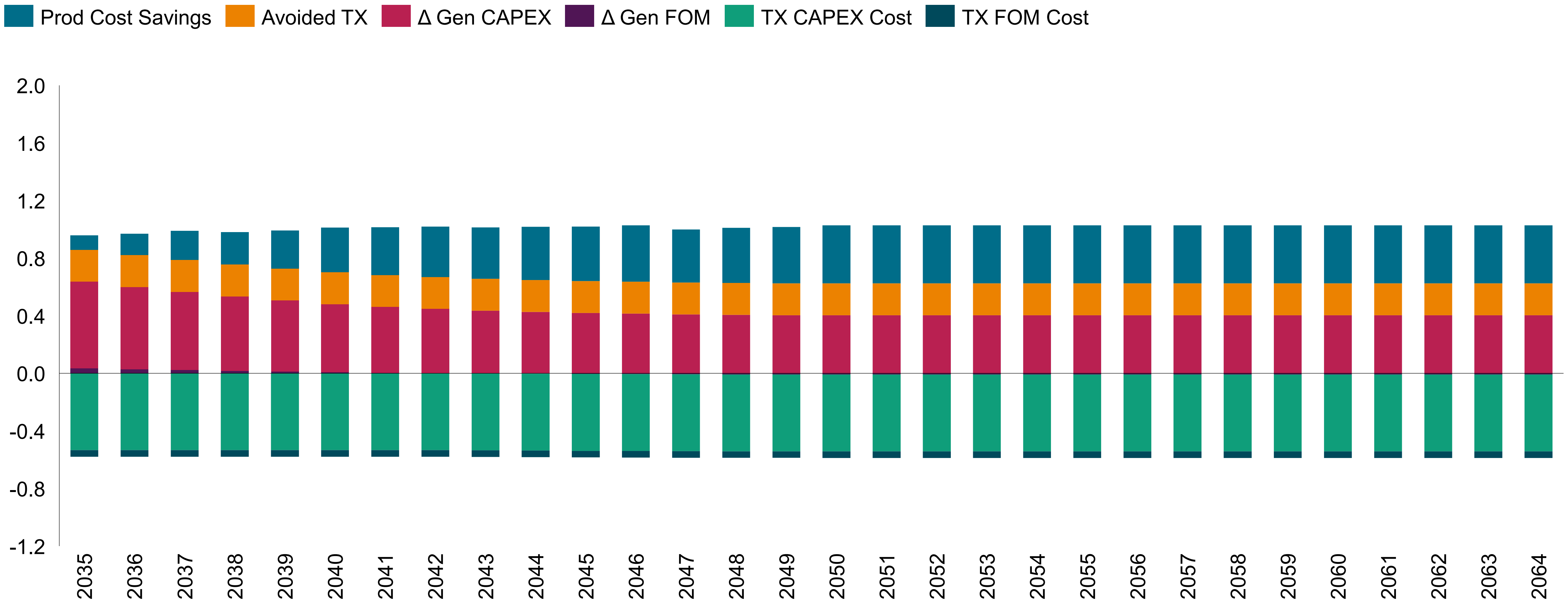


Source: S&P Global Energy

The Constrained High Demand case shows a higher percentage increase in benefits than the Unconstrained case, relative to the Base Demand case, because of more transmission links

Annual Benefits and Costs ($ Billions real 2024)

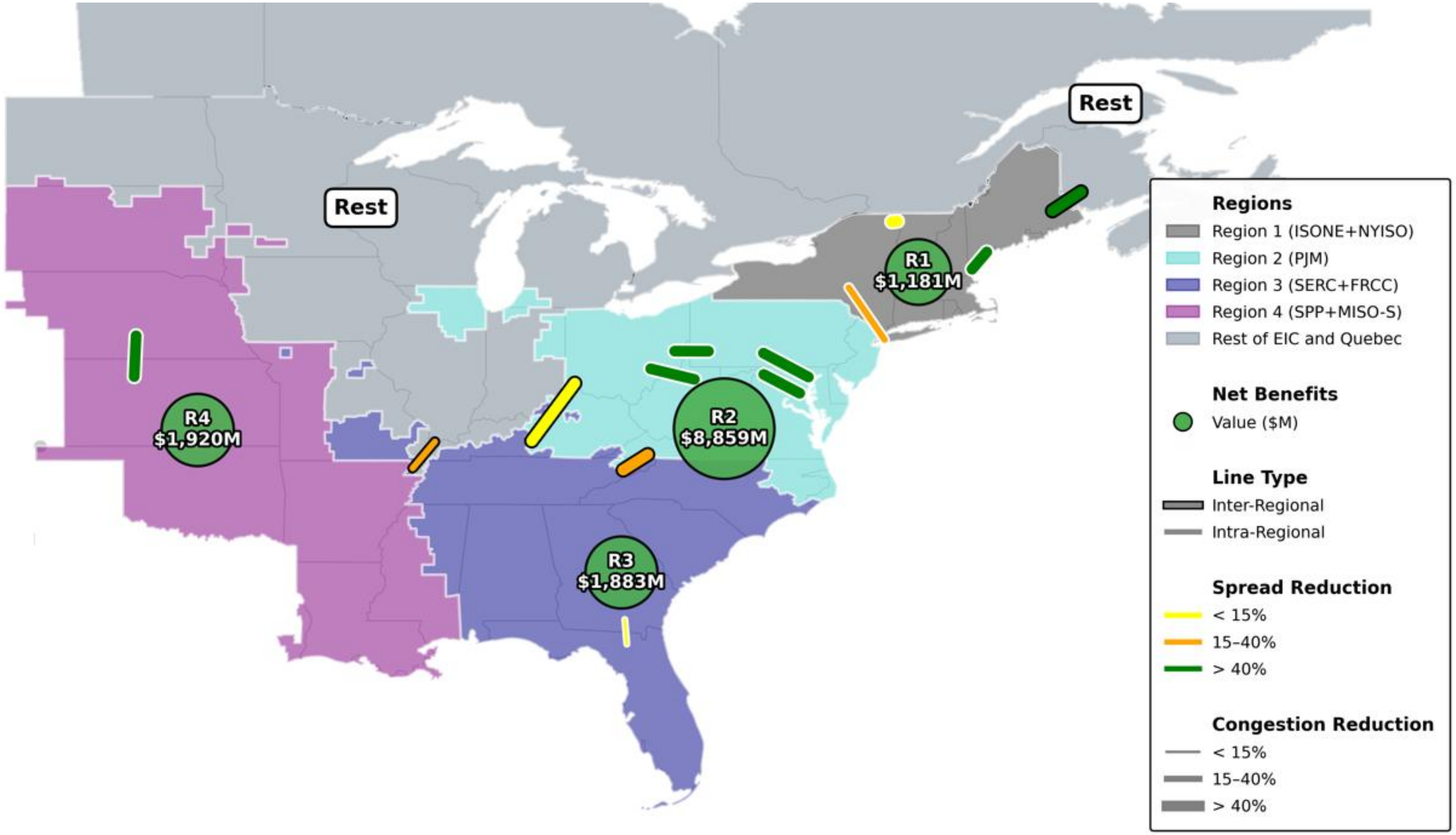
Constrained Case



Source: S&P Global Energy

Allowing interregional transmission in the Unconstrained results in significant Net Benefits across all regions, with wider spread and congestion relief compared to the Constrained case

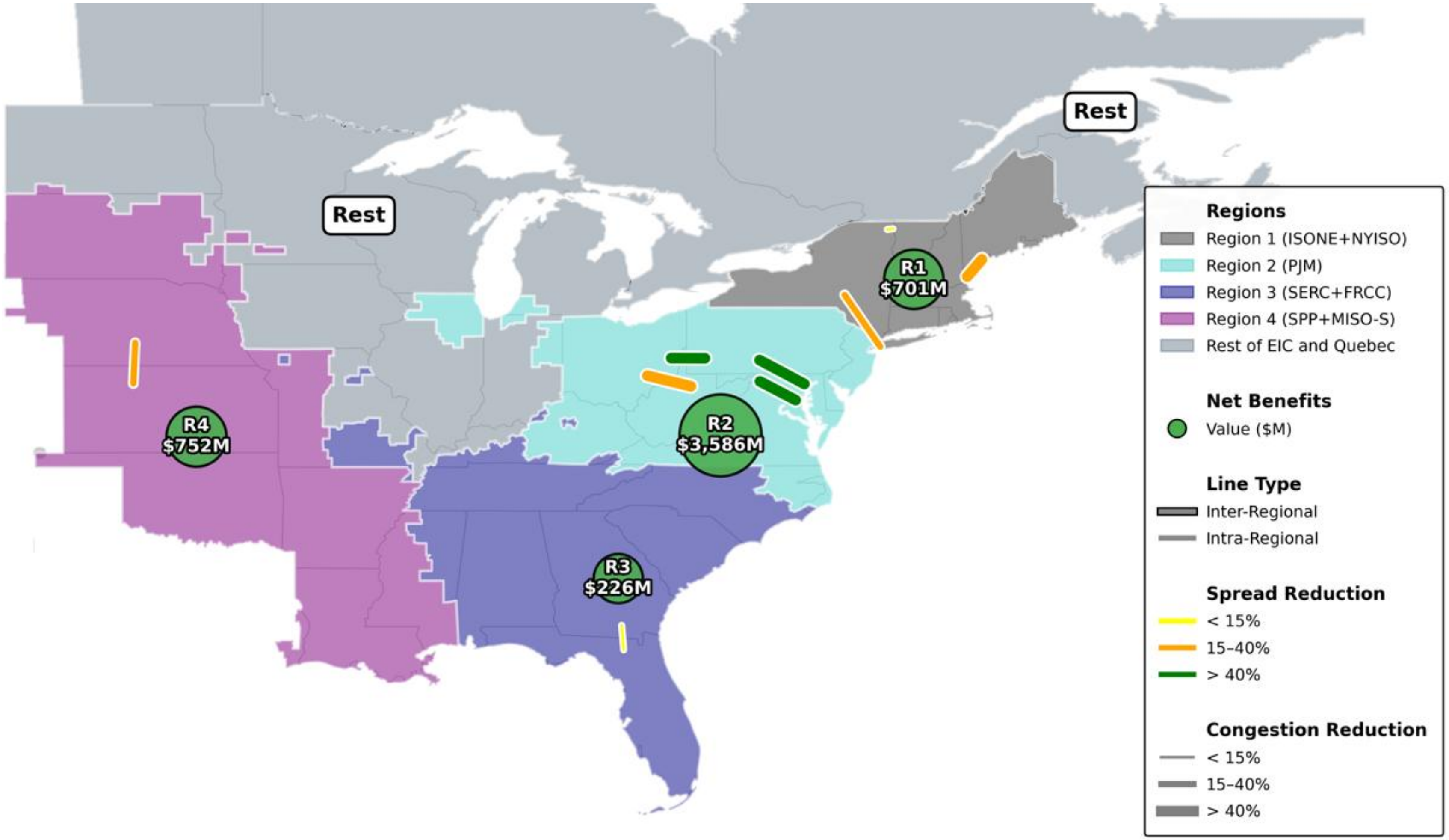
Transmission Impact Analysis in the Unconstrained High Demand Case



The net benefits reflect the full horizon (over a 40-year transmission economic lifetime), while the spread and congestion reduction is for the initial year 2035, by when all the selected transmission expansion come online. These selected transmission are represented by lines on the map showing approximate locations and are not to scale. This study provides a high-level analysis and does not consider actual route information or permitting.
Source: S&P Global Energy

In the High Demand Constrained case, PJM sees the largest Net Benefits and the highest spread and congestion relief due to additional transmission capacity

Transmission Impact Analysis in the Constrained High Demand Case



The net benefits reflect the full horizon (over a 40-year transmission economic lifetime), while the spread and congestion reduction is for the initial year 2035, by when all the selected transmission expansion come online.
These selected transmission are represented by lines on the map showing approximate locations and are not to scale. This study provides a high-level analysis and does not consider actual route information or permitting.
Source: S&P Global Energy

Similar to the Base Demand case, the retail rate savings are also generally positive in the High Demand case

This weather-normalized analysis excludes potential extra value from extreme-weather performance and ancillary services, which could increase retail rate savings. The Unconstrained scenario yields higher savings than the Constrained one, mainly due to added value from interregional transmission expansion. While the selected transmission projects have benefit-cost ratios above 1.0, their impact on retail rates is modest because their small scale relative to the overall system spreads benefits across a large load base

Unconstrained High Demand Case

No.	Region Center	2035 Annual Benefits ($M nominal)	2035 Annual Wholesale Demand (GWh)	2035 Annual Savings Benefits/ Demand (cents per kWh)	2050 Annual Benefits ($M nominal)	2050 Annual Wholesale Demand (GWh)	2050 Annual Savings Benefits/ Demand (cents per kWh)
1	ISONE + NYISO	194	311,218	0.0624	59	379,079	0.0156
2	PJM	473	1,217,582	0.0389	897	1,420,908	0.0631
3	SERC + FRCC	189	1,174,785	0.0161	177	1,357,025	0.0130
4	SPP + MISO S	134	630,027	0.0213	177	783,876	0.0226

Constrained High Demand Case

No.	Region Center	2035 Annual Benefits ($M nominal)	2035 Annual Wholesale Demand (GWh)	2035 Annual Savings Benefits/ Demand (cents per kWh)	2050 Annual Benefits ($M nominal)	2050 Annual Wholesale Demand (GWh)	2050 Annual Savings Benefits/ Demand (cents per kWh)
1	ISONE + NYISO	95	311,218	0.0304	83	379,079	0.0219
2	PJM	256	1,217,582	0.0210	362	1,420,908	0.0255
3	SERC + FRCC	67	1,174,785	0.0130	-52	1,357,025	-0.0038
4	SPP + MISO S	24	630,027	0.0039	128	783,876	0.0164

This is based on weather-normal analysis and doesn't include any adjustment due to extreme weather and ancillary services.
Source: S&P Global Energy

Contents

Our methodology leverages historical event data to quantify extreme weather and ancillary service adjustment factors

Extreme Weather Adjustment Factor

This analysis applies a screening level extreme weather adjustment factor to reflect the ability of transmission to reduce event driven energy price premiums. The adjustment is not intended to represent a full chronological production cost simulation of extreme weather operations. Rather, it reflects the observed historical relationship between regional scarcity events, price premiums, and the ability of neighboring regions to provide imports when weather impacts are not fully coincident

Historical Event-Based Adjustments

Based on historical event experience and reliability assessments, adjustment factors are set between 7% and 15% of the estimated extreme weather premium, with higher values assigned to regions with greater fuel deliverability constraints or more concentrated scarcity exposure

Ancillary Service Benefit Adjustments

Ancillary service benefits are captured through a separate annual adjustment reflecting the ability of transmission to improve reserve sharing, reduce balancing costs, and provide access to geographically diverse regulation and ramping resources. Because ancillary service costs are typically smaller than energy and capacity cost impacts, the adjustment is limited to 1.5%–3.5% in the base case, with 5% reserved for some regions in the High Demand case

Application Scope

These factors are annual averages, intended for use in high-level benefit-cost assessments and these factors are grounded in historical analysis and are not the output of a full production cost model

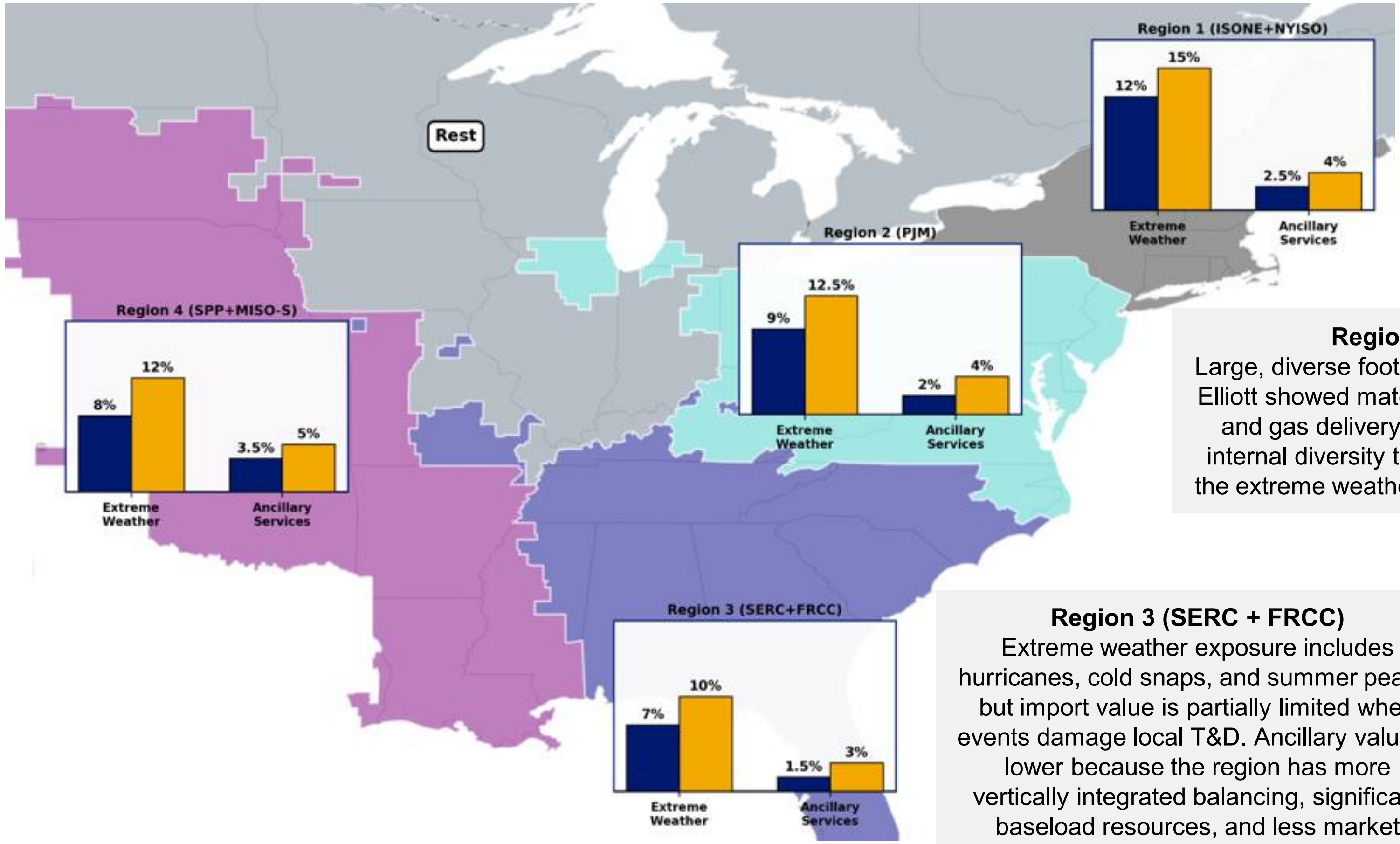
The methodology does not capture all possible weather correlations

Source: S&P Global Energy, Winter Storm Elliott, NTNS, NTPS, Grid Strategies

Extreme weather adjustment factors peak in the Northeast due to winter gas dependency, while ancillary service scaling factors are highest in the wind-heavy SPP and MISO-S region

Extreme Weather and Ancillary Service Adjustment Factors

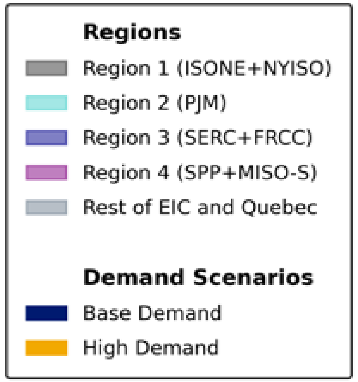
Region 4 (SPP + MISO S)
Uri/ Elliott type storms can create scarcity, fuel disruptions, and high outage rates. Ancillary service scaling factors are the highest among regions because SPP has high wind penetration and benefits materially from geographic diversity, ramping support, and flexibility across seams



Region 1 (ISONE + NYISO)
Highest extreme weather adjustment factors because of winter gas dependency, pipeline constraints, fuel scarcity risk, and high event driven power/gas premiums

Region 2 (PJM)
Large, diverse footprint, but Winter Storm Elliott showed material correlated outage and gas delivery risk. PJM has more internal diversity than the Northeast, so the extreme weather factor is slightly less

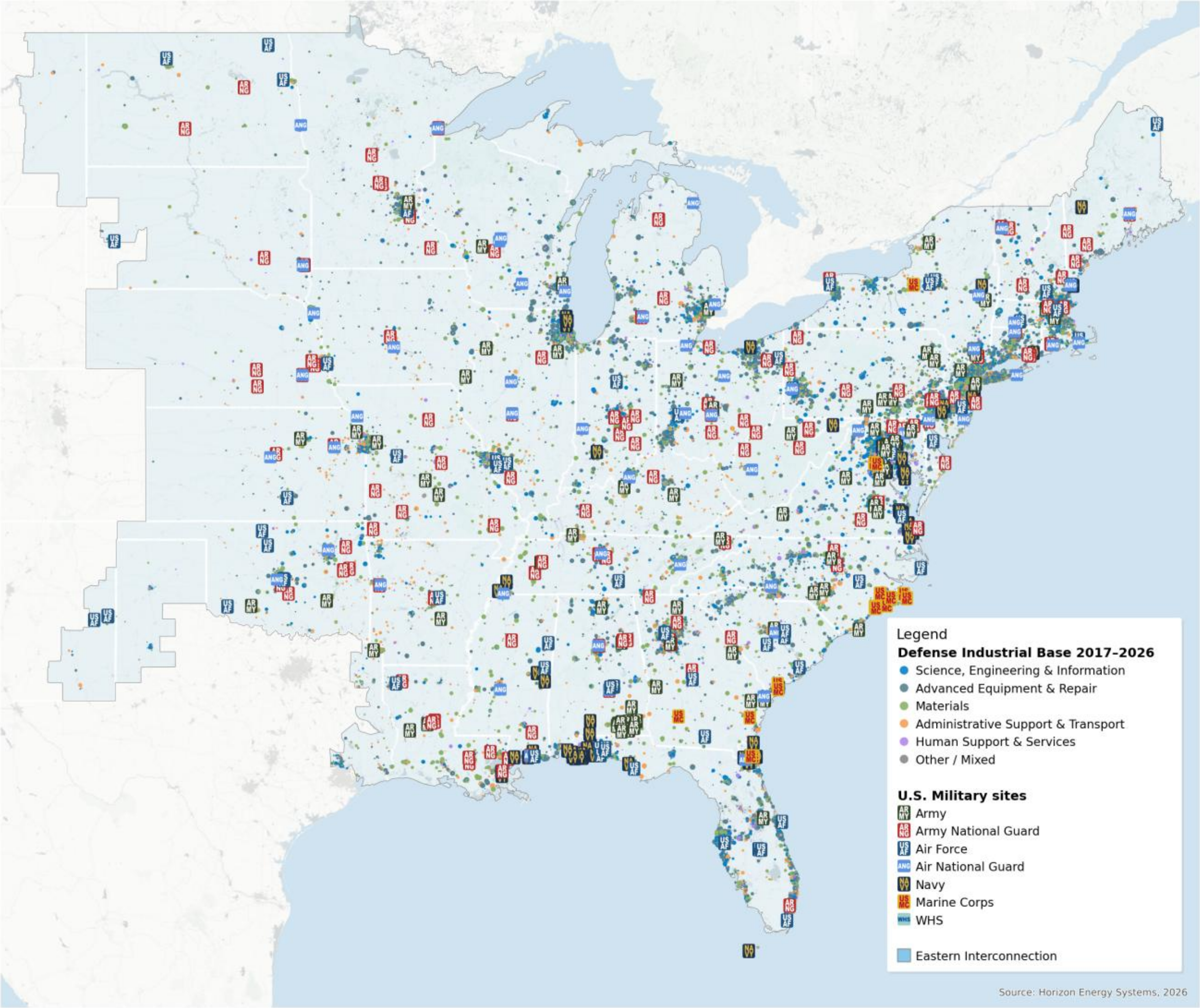
Region 3 (SERC + FRCC)
Extreme weather exposure includes hurricanes, cold snaps, and summer peaks, but import value is partially limited when events damage local T&D. Ancillary value is lower because the region has more vertically integrated balancing, significant baseload resources, and less market transparent ancillary scarcity pricing



Scaling factors here represent the incremental adjustment to the APC savings for the respective base or high demand scenarios. For example, Region1 will get a total of 19% increase (or a 1.19 multiplier) in the High Demand case, compared with a 14.5% increase in the base demand case.
Source: S&P Global Energy, Winter Storm Elliott, NTNS, NTPS, Grid Strategies

Contents

National Security and Defense methodology



- This is a conservative case because it does not include a quantitative analysis of regional defense energy requirements
- Quantitative examinations of grid reliability and national defense remain at an early stage
- Region 3 covers the whole SERC, including FRCC; however, for the National Security analysis, the focus is more on the southeastern states
- Slide 81 contains an overview of a state-focused study completed by Energy Strategies and Converge Strategies, applying a power flow analysis to the defense footprint in Virginia. Similar analyses could be conducted for additional states or regions in the future
- For a more in-depth qualitative assessment of the dependence of our national defense enterprise on the commercial electric grid, and the policy implications and recommendations of these findings, please visit https://ngrid.com/poweringgrowth

Source: Converge Strategies, Horizon Energy Systems 2026, ourgridfuture.org

Transmission that increases system reliability supports defense energy resilience and security, and can help meet energy availability requirements for critical missions

Defense Energy Definitions & Requirements

Transmission for National Defense

In the FY26 NDAA[1], Congress required the Department of War to coordinate on grid reliability and transmission infrastructure to mitigate risks to mission critical loads and infrastructure, consistent with Department energy policy

Department of War Energy Policy

The General Energy Policy of the DoW is to "ensure the readiness of the armed forces for their military missions by pursuing energy security and energy resilience"

Energy Security[2] & Energy Resilience[3]

- Access to reliable supplies of energy and the ability to protect and deliver sufficient energy to meet mission essential requirements
- The ability to avoid, prepare for, minimize, adapt to, and recover from energy disruptions to ensure energy availability and reliability sufficient to provide for mission assurance and readiness

Energy Availability[4]

- The availability of required energy at a stated instant of time or over a stated period of time for a specific purpose
- Military missions must be provided with up to 99.9999% energy availability[5], depending on their criticality

1. FY26 NDAA Section 2847, 2. Energy security 10 U.S.C. 101(e)(7), 3. Energy resilience 10 U.S.C. 101(e)(6), 4. Energy availability 10 U.S.C. 2920 (h)(1), Energy availability standard 10 U.S.C. 2920(a)(2).
Source: Converge Strategies

Transmission expansion supports three interdependent layers of defense activity ("defense footprint"): installations and missions, defense communities, and the defense industrial base

Defense Footprint Definitions

Military Installations[1] and Missions[2]

An "installation is a base, camp, post, station, yard, center, homeport facility for any ship, or other activity under DoW jurisdiction

Installations may host multiple missions, such as cyber operations, air defense, or missile radar. Critical missions are "those aspects of the missions of an installation, including mission essential operations, that are critical to successful performance of the strategic national defense mission"

Defense Communities

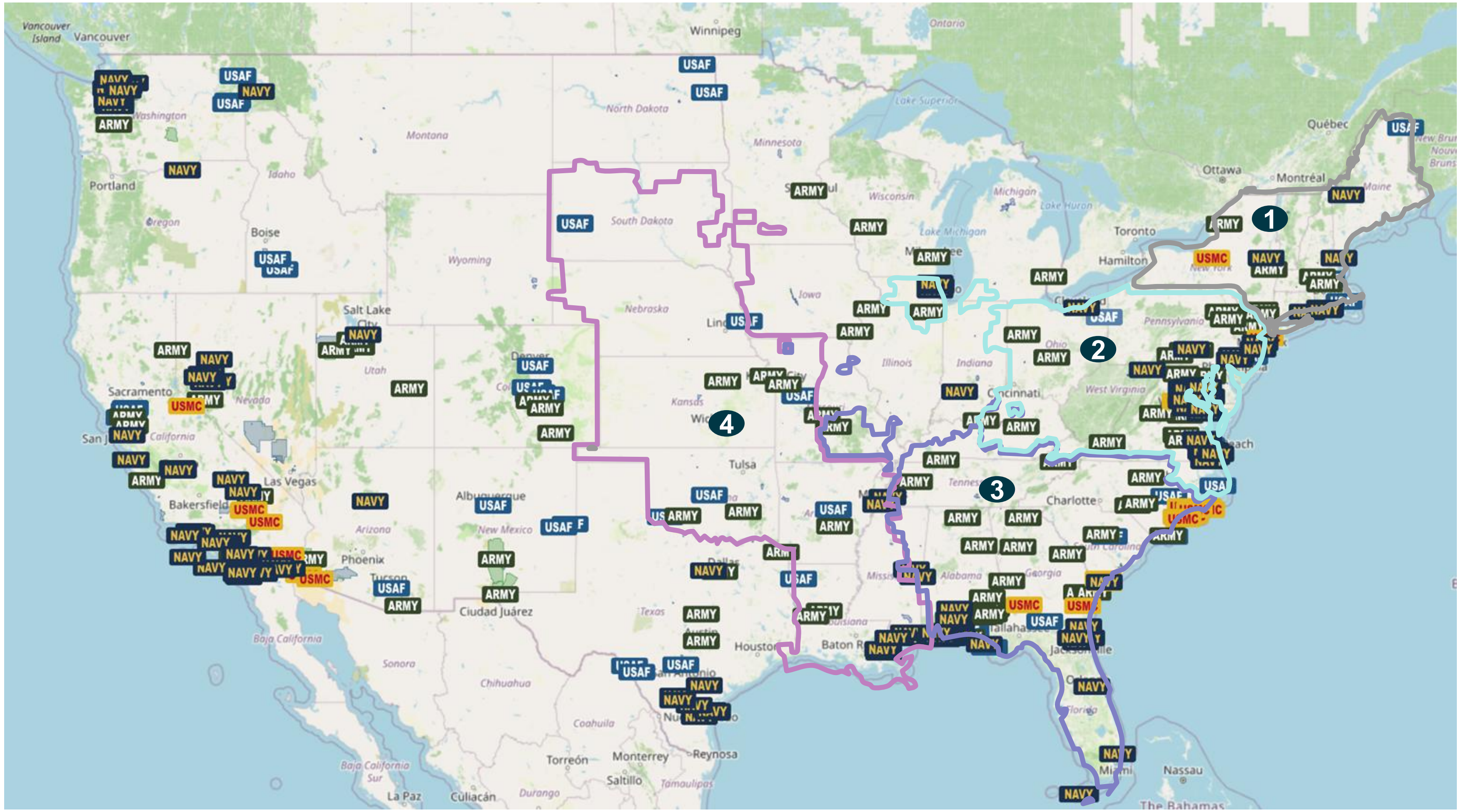
Defense communities are the towns, cities, counties, regions, and states that host the nation's military missions, installations, and industrial partners

Defense Industrial Base (DIB)

The DIB is the network of organizations, facilities, and resources that perform research and development; design; produce; and maintain military weapon systems, subsystems, components, or parts to satisfy military requirements. There are an estimated 200,000 companies within the U.S. defense industrial base

1. Military installations DoDI 1000.15, 2. Critical missions - U.S. Department of Defense, Office of the Under Secretary of Defense for Acquisition and Sustainment (USD(A&S). (2021). Metrics and Standards for Energy Resilience at Military Installations. Washington, DC.
Source: Converge Strategies.

There are 450+ major military installations in the continental U.S. and thousands of smaller installations and facilities



Active-Duty Installations in CONUS, by Service

No.	Region Center	Number of Major Military Installations
1	ISONE + NYISO	35
2	PJM	75
3	SERC + FRCC	65
4	SPP + MISO S	35

For the above analysis, the focus is given more to the southeastern states
Source: Horizon Energy Systems (2026)

Transmission investment is needed to close defense energy resilience gaps and protect critical missions

Mission Assurance

Defense missions around the world depend on physical and digital infrastructure located in the U.S., and domestic military installations are almost entirely dependent on the civilian power grid. DoW's energy availability standards for critical missions require no more than 30 seconds of downtime per year. No region currently meets these standards

Long-Duration Outages

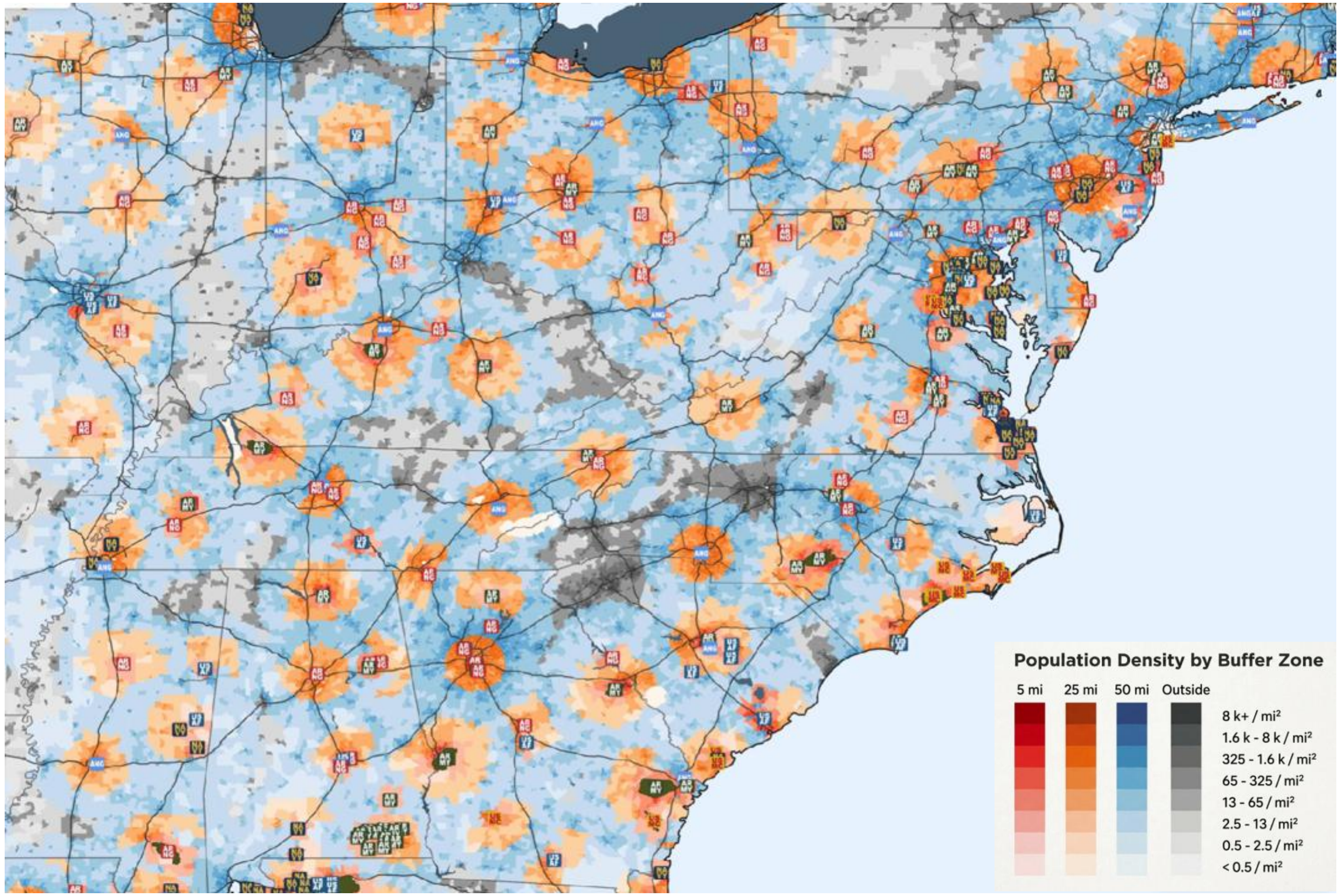
Defense policy requires critical missions to operate independently for 14 days using backup power, but recent disasters have exceeded this planning horizon. On-site resilience systems are necessary for installations to remain running during short duration outages but are not sufficient for longer-duration outages. Transmission investments can mitigate the risk of multi-week outages

Cascading Regional Risks

Transmission can mitigate the regional risks of large-scale outages. Widespread outages that impact multiple bases simultaneously and in the same region can compromise fallback options and decrease the ability of installations to support one another

Source: Converge Strategies.

Military missions rely on the electricity-dependent civilian infrastructure in defense communities and on the defense personnel that live off base



Population Density with 5, 25, and 50mi Defense Community Buffer Zones

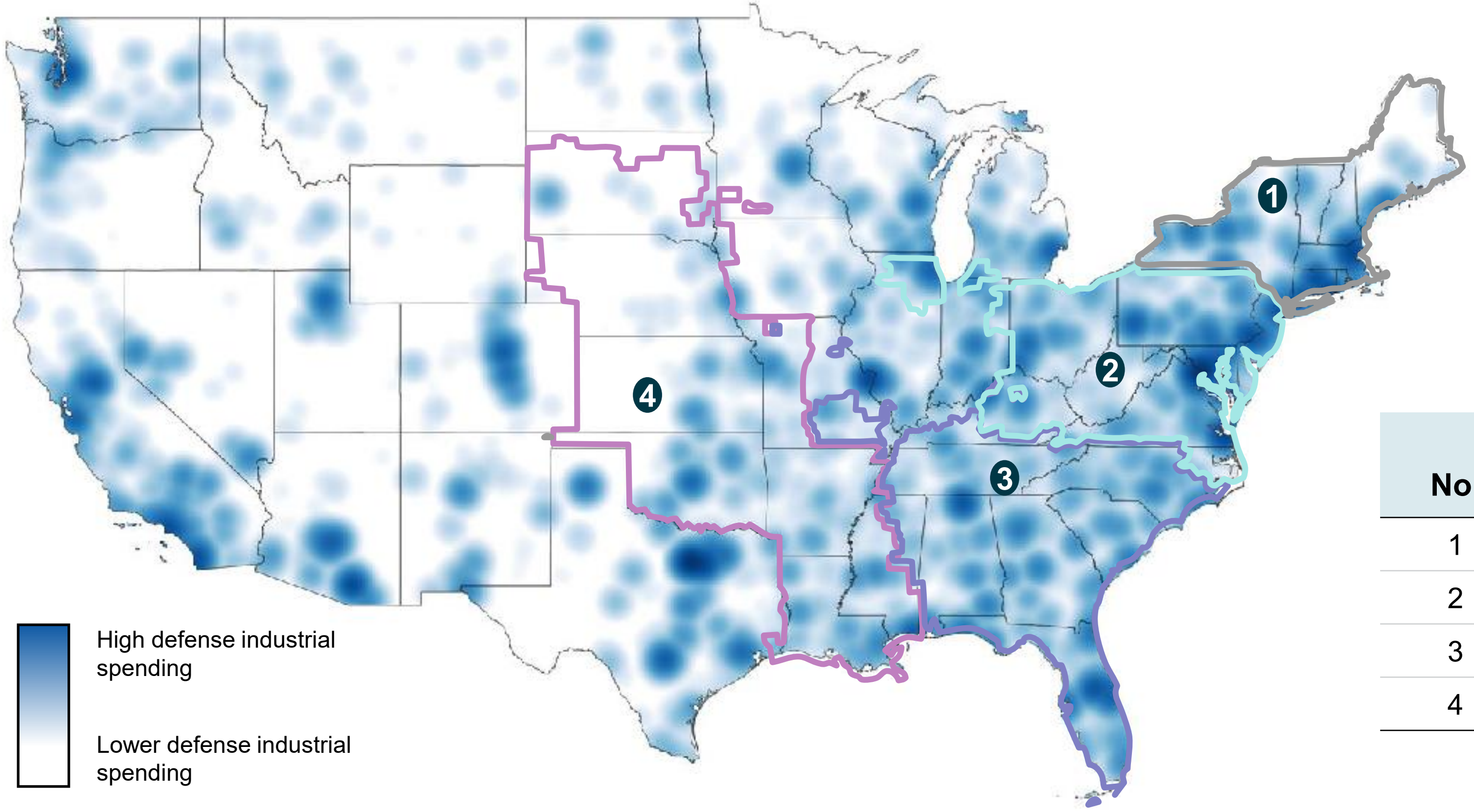
Source: Horizon Energy Systems (2026).

Defense readiness depends on civilian community systems; transmission planning should account for community loads and outage risk to prevent cascading impacts

Utility Interdependence	Military installations rely on the civilian water, wastewater, communications, natural gas, and transportation systems that are located within surrounding defense communities and outside of military control. Power outages can cause cascading failures across these interdependent systems
Community Readiness	More than 70 % of military personnel and their families live outside the fence line, along with nearly all the civilian personnel who work for the military. Power outages at their homes directly degrade readiness
Coordinated Planning	Defense communities are integral to mission capability. Transmission planning can take defense community loads, which reach hundreds or thousands of megawatts, into account alongside the loads of military installations

Source: Converge Strategies

Defense spending totaled $423B in FY24. There is a significant defense industrial presence in the regions analyzed for this study

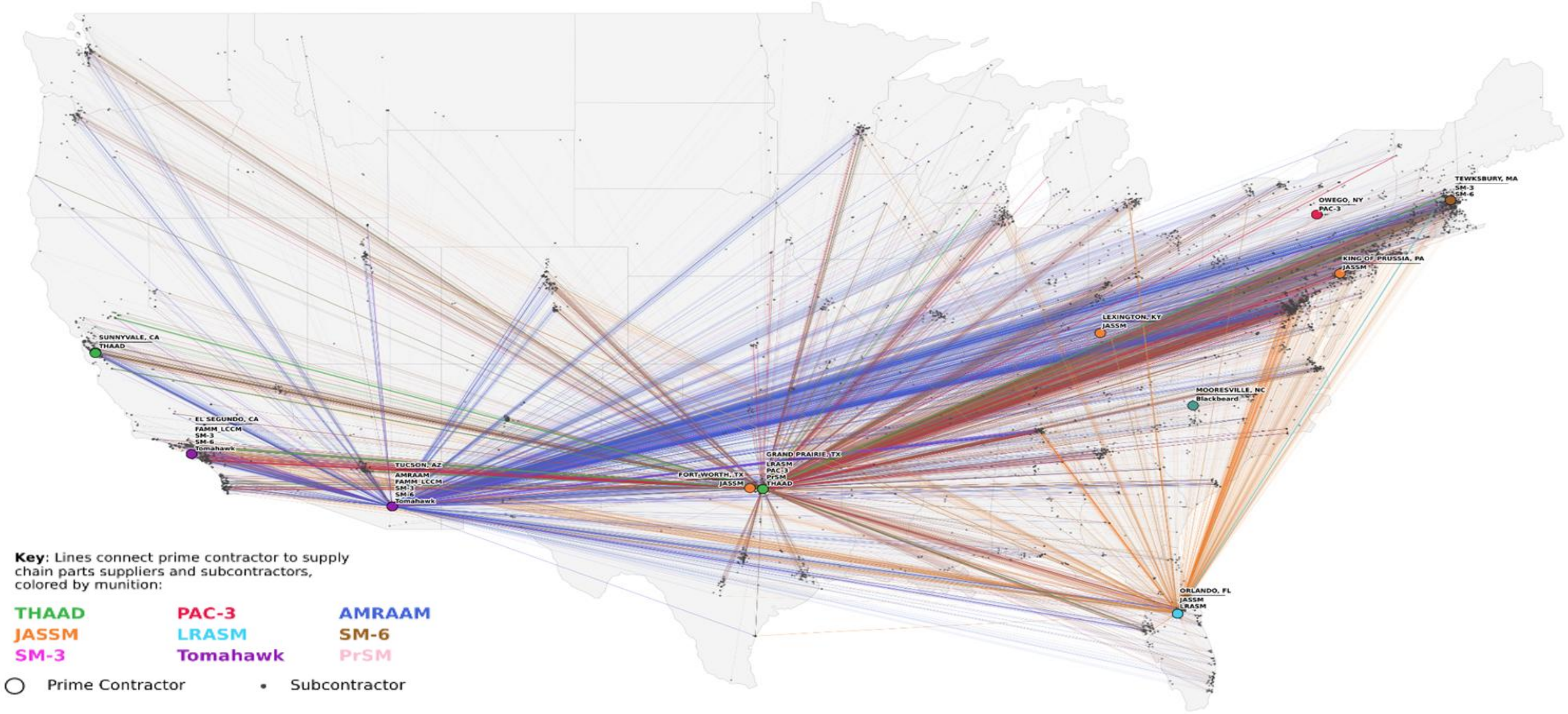


U.S. Defense Contract Spending Heat Map (2017-2025)

No.	Region Center	Contract Spending ($ B)
1	ISONE + NYISO	54
2	PJM	110
3	SERC + FRCC	55
4	SPP + MISO S	11

For the above analysis, the focus is given more to the southeastern states
Source: Horizon Energy Systems (2026)

Defense production is nationally networked, and transmission can improve reliability for weapons systems manufacturing and supply chains



Contractor locations for the critical weapons systems identified by Pentagon's Munitions Acceleration Council

Source: Horizon Energy Systems (2026)

Transmission capacity is a critical input to defense industrial readiness

DIB Vulnerability	The Department's Defense Industrial Base Sector-Specific Plan states the DIB does not include the commercial power infrastructure that DoW warfighters and support organizations rely on to meet operational needs, even though the DIB depends on that commercial infrastructure to function. That gap in ownership and oversight is a vulnerability: no single entity is accountable for the transmission capacity the DIB needs to operate
Production Constraints	Growing electrification, robotics, and advanced manufacturing are pushing DIB facilities toward higher and more continuous power draws, turning transmission capacity into a direct constraint on production timelines and readiness
Industrial Readiness	Transmission investment is production capacity, not just infrastructure spending. As Powering the Fight argues, munitions and equipment output scale with the grid's ability to deliver power to manufacturing sites, making transmission expansion a direct lever for defense industrial readiness, not a downstream utility concern

Source: Converge Strategies

Region 2 PJM has the highest aggregate defense spending and active-duty military exposure, with concentrations in Mid-Atlantic and the South

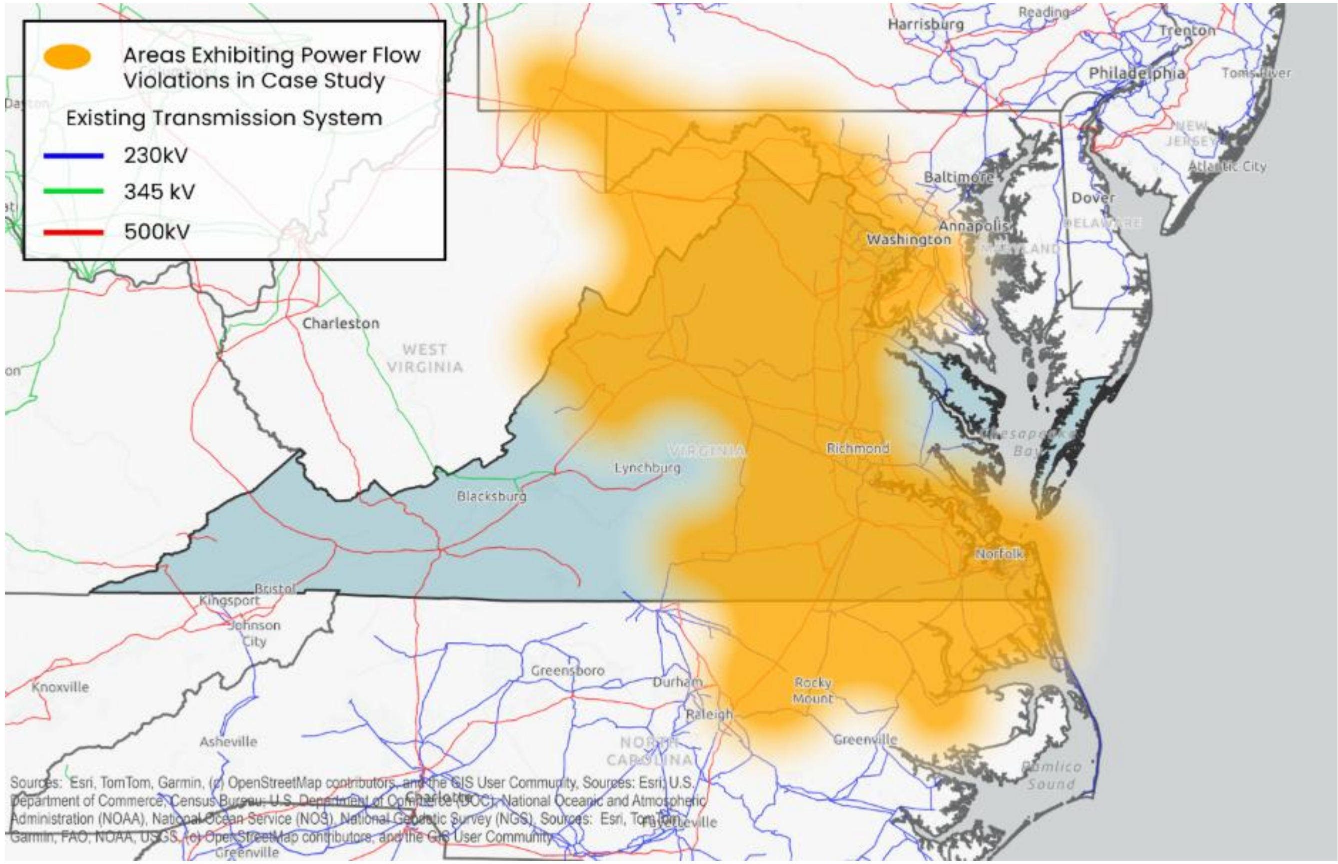
	pjm	SERC	SPP / MISO	ISO new england / New York ISO Independent System Operator
Example Missions	Home of the Pentagon, national intelligence agencies, major air bases, and the world's largest naval station	Major operational missions from across the services: Army, Navy, Air Force, Space Force, and Marine Corps	Strategic nuclear forces from South Dakota to Louisiana, including bombers, and U.S. Strategic Command	Major naval installations along the coast from Portsmouth Naval Shipyard in Maine to SUBASE New London
Personnel	530,000	540,000	173,500	130,000
Payroll	$44 billion	$33.78 billion	$10 billion	$7.8 billion

For the above analysis, the focus is given more to the southeastern states
Source: Converge Strategies

Virginia's transmission system can reliably support only a 5-10% defense load increase, 175-350 MW, before requiring upgrades, less than a single large datacenter

A first of its kind state-level power analysis focusing on defense requirements was conducted in Virginia, chosen for its high concentration of data center development and critical defense assets. Results across four scenarios indicated that the transmission systems has little margin for the type of load growth Virginia is already experiencing

Moderate 20% Load Increase	**~$44M/30 mi new lines**
High 50% Load Increase	**~$221M/91 mi new lines**
Extreme 100% Load Increase	**~$3.9B/958 mi new lines**
State Emergency Compounding Conditions	**~$768M/159 mi new lines**



Source: https://convergestrategies.com/unleashing-virginia/

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