Transmission Landscape and Outlook:
Proactive Planning for a More Cost-effective and Affordable Energy Transition

PRESENTED BY

Johannes Pfeifenberger

PRESENTED AT

2025 Governors' Advisors Energy Policy Institute & States Transmission Summit

October 9, 2025

Brattle

Topics discussed today

1. The “3P” challenges to transmission
2. How much are we investing in transmission
3. The grid challenges today (looking forward)
4. Transmission policies to support a more cost-effective and affordable energy transition
5. The challenge of planning interregional transmission

The three "Ps" of Transmission Development

Planning

- Silioed, local and regionally-focused, planning processes are not designed to build the most cost-effective, most valuable transmission grid … infrastructure that reduces electricity costs
- No effective planning processes exist for interregional transmission, which offers some of the largest opportunities for cost savings

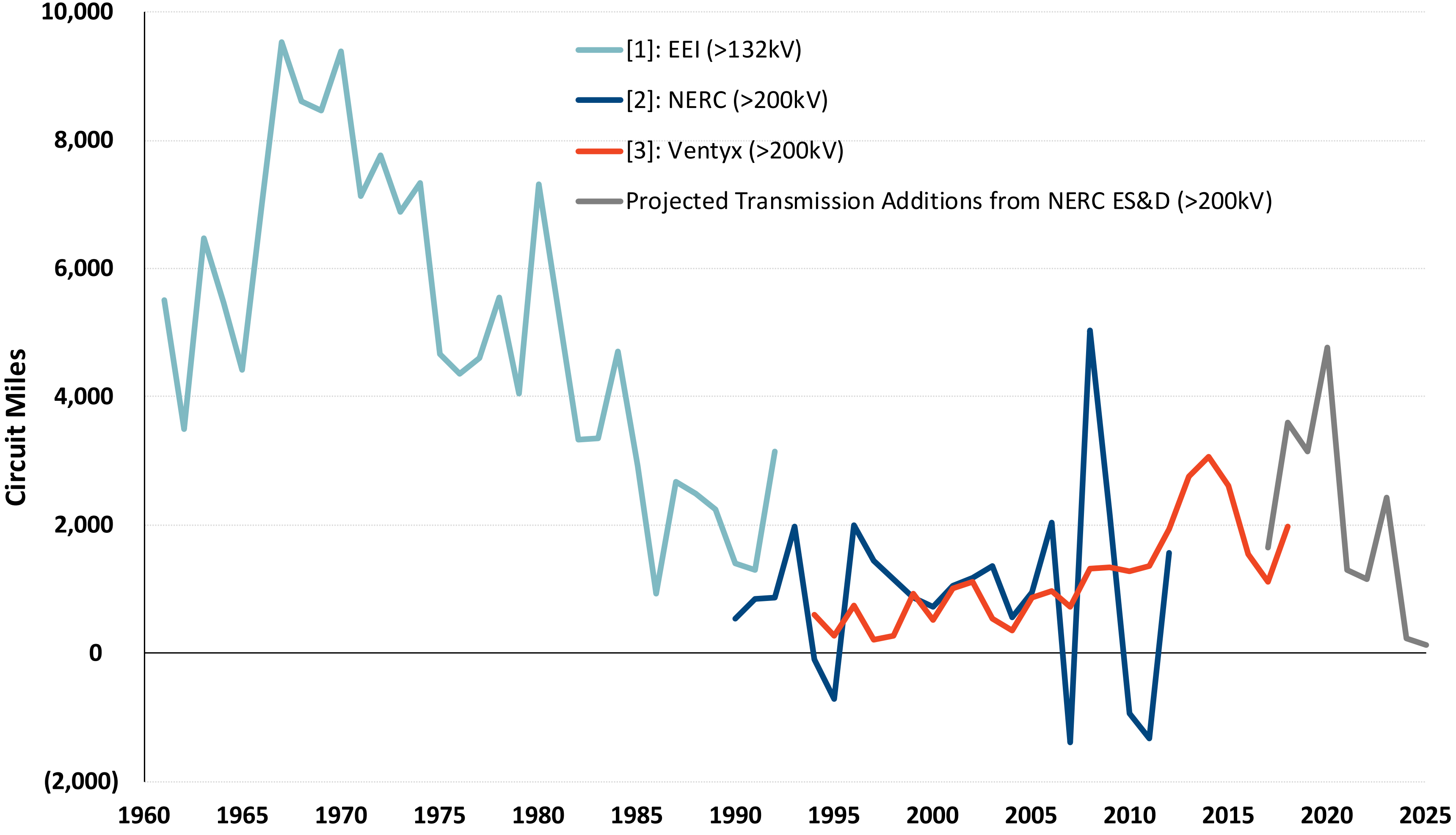
Permitting

- Most planned transmission projects have been able to overcome permitting challenges
- But permitting processes are (too) time consuming, increasing costs and uncertainties, and incompatible with the new "need for speed"

Paying

- "Cost allocation" for transmission projects can become a significant barrier to beneficial investment if utilities, states, and regions cannot agree on how to pay for the infrastructure
- However, well-working models exist … and finding agreement is easier for more cost-effective, more valuable projects

Historical U.S. Transmission Development



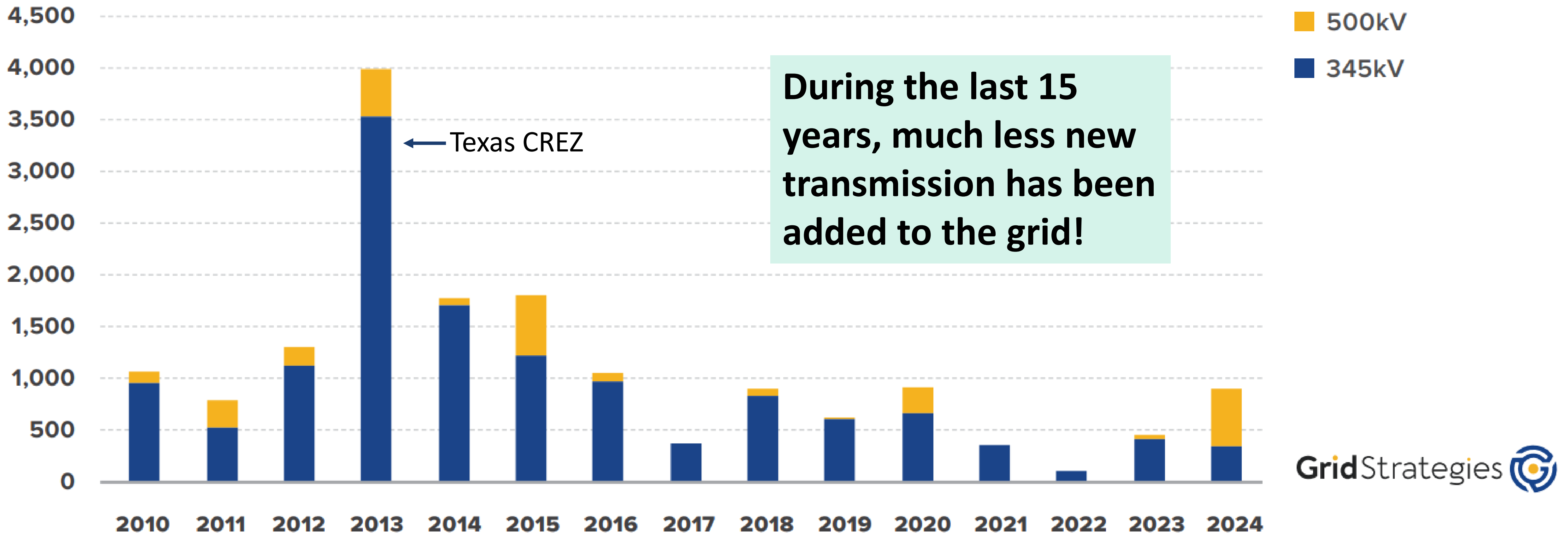
Most of the U.S. transmission grid was built in the 1960s and 70s (and needs to be refurbished or replaced now)

[1]: Circuit miles of overhead electric lines from EEI's Historical Statistical Yearbook. Data excludes REA cooperatives.
[2]: Courtesy of the North American Electric Reliability Corporation. NERC data is only available for lines 200kV and above. Note: transmission line additions are calculated as the difference in existing tranmission between the current and prior year (i.e. 2003 additions = 2003 miles - 2002 miles).
[3]: Ventyx Suite.

New U.S. EHV Transmission Line Additions 2010-2024

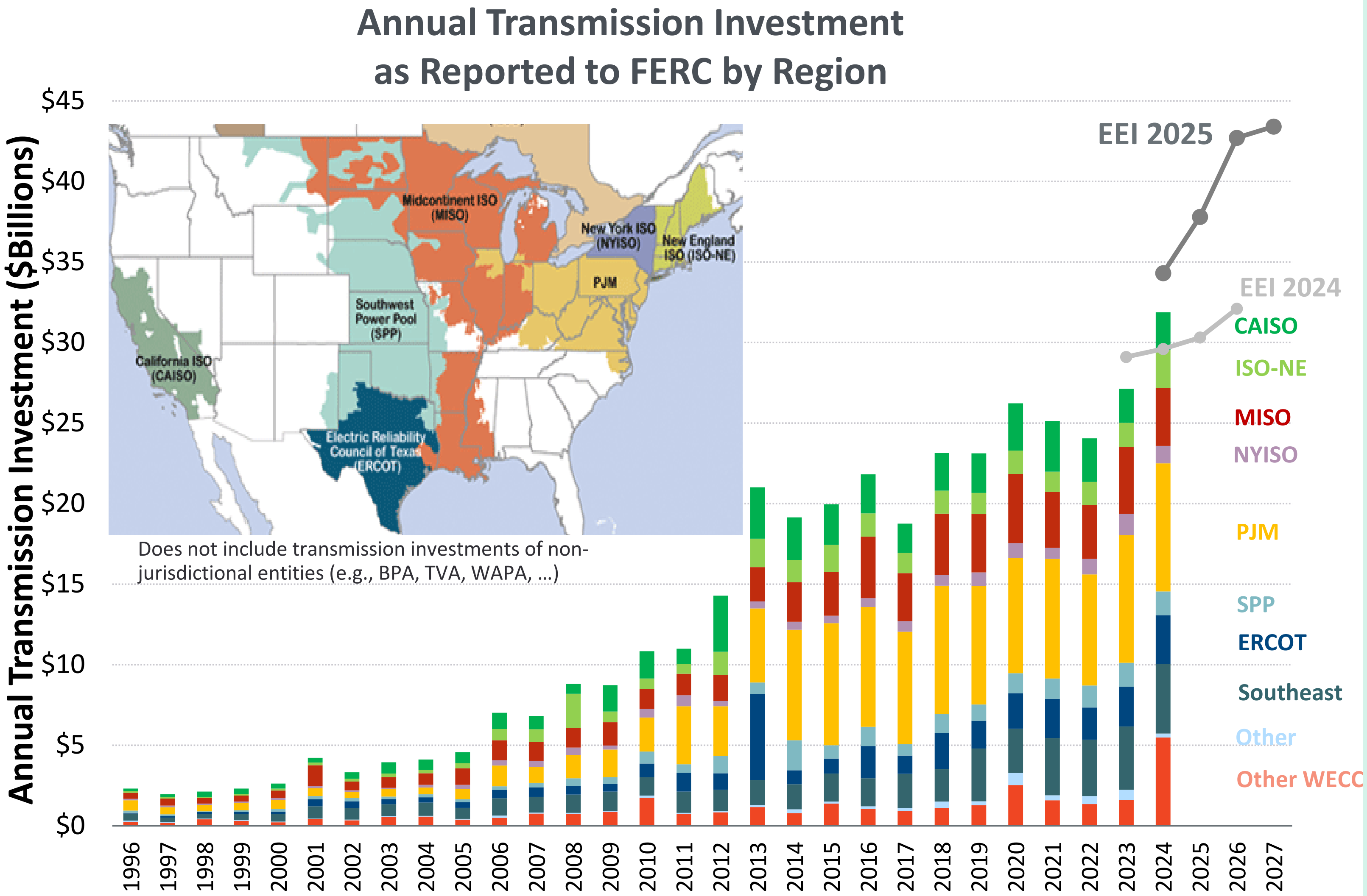
UPDATED FIGURE 1 | Miles of new 345 kV+ transmission lines built over the last 15 years (updated using July 2025 data)[31]

Source: ACEG_Grid-Strategies_Fewer-New-Miles-2025_Rev-1.pdf



During the last 15 years, much less new transmission has been added to the grid!

Annual U.S. Transmission Investments 1996-2024



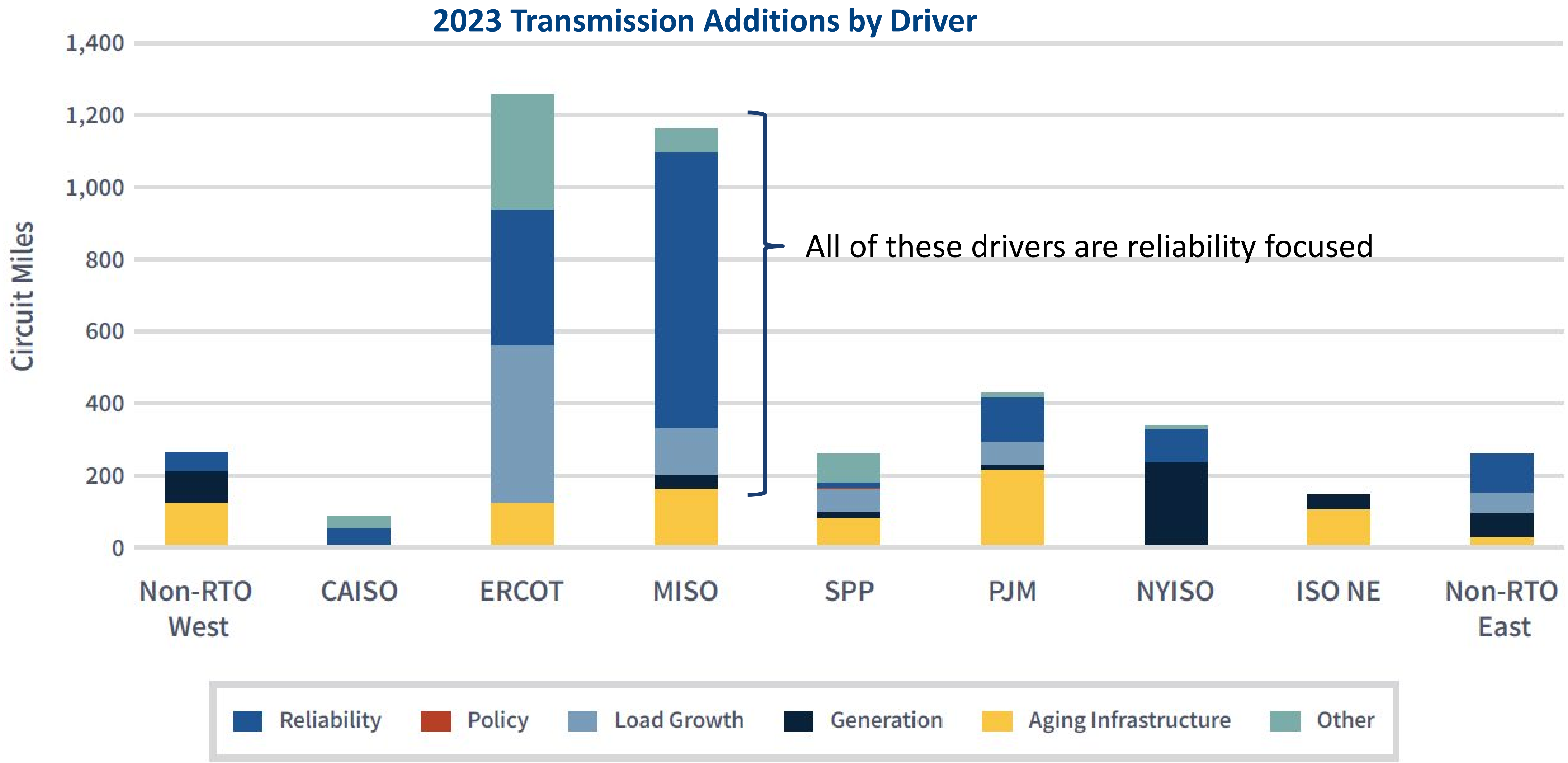
Sources: The Brattle Group analysis of FERC Form 1 Data; EEI "Historical and Projected Transmission Investment" most recent accessed here https://www.eei.org/-/media/Project/EEI/Documents/Resources-and-Media/bar_actual_and_projected_trans_investment.pdf

Yet, total transmission investment has steadily increased in the last 30 years!

Last year, we crossed $30 million in annual U.S. transmission investments!

- Most of it is justified solely based on reliability needs (without benefit-cost analysis); 50% based on “local” utility criteria (aging assets; without going through regional planning processes)
- Other than in MISO, very few projects justified based on multi-driver planning
- Essentially no interregional transmission is being planned (other than by merchant developers)

Transmission additions are mostly driven by reliability criteria



Source: FERC Staff Report: 2023 State of the Markets (March 21, 2024), Figure 15 (based on C3 Group data)

Major Grid Challenges Looking Forward

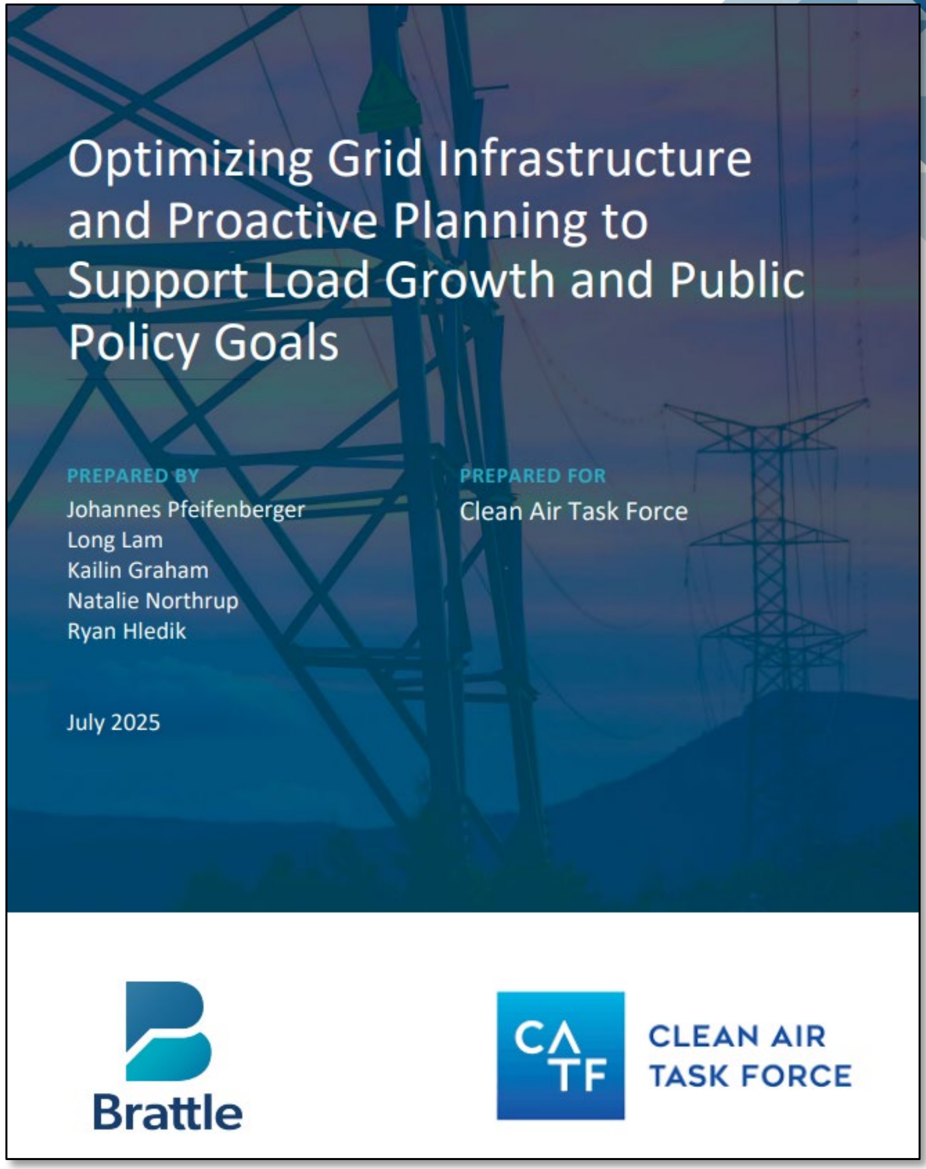
The US electric power system is entering a period of rapid and transformational change due to:

- Accelerating electrification of buildings and transportation
- Re-shoring of industrial activity
- Unprecedented surge in demand from data centers
- Aging grid and generation infrastructure

Meeting this demand will require significant investments grid infrastructure, which can be costly and take a long time:

- Many new large customers are prepared to pay a premium or invest in this infrastructure themselves to avoid interconnection delays
- Capital needs likely exceed the financial capabilities of many utilities
- Affordability challenges and impacts on existing customers create challenges and regulatory risks

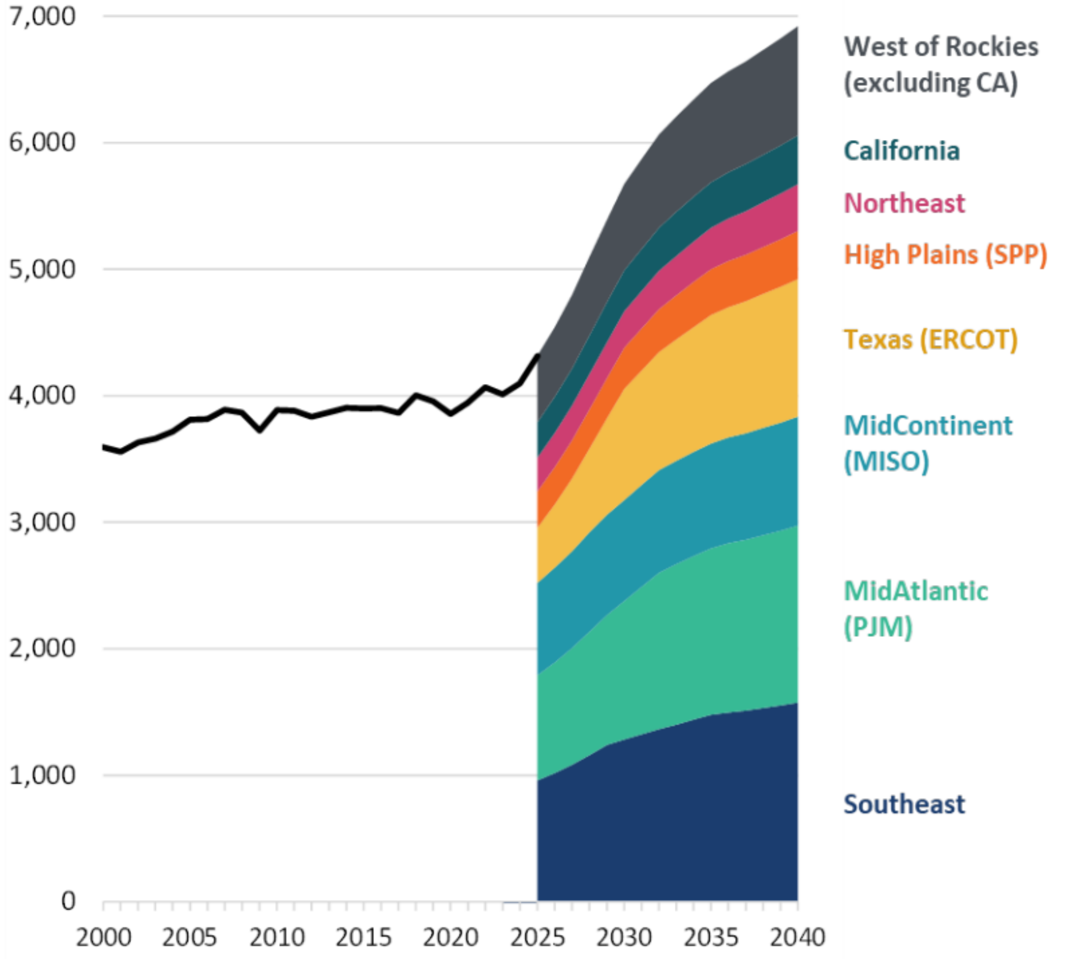
Key question: How can utilities, system planners, policymakers, and regulators collaborate to serve new loads more quickly and cost-effectively, while still meeting state and corporate energy goals reliably and affordably?



Report link

Accelerating Load Growth and Capital Needs

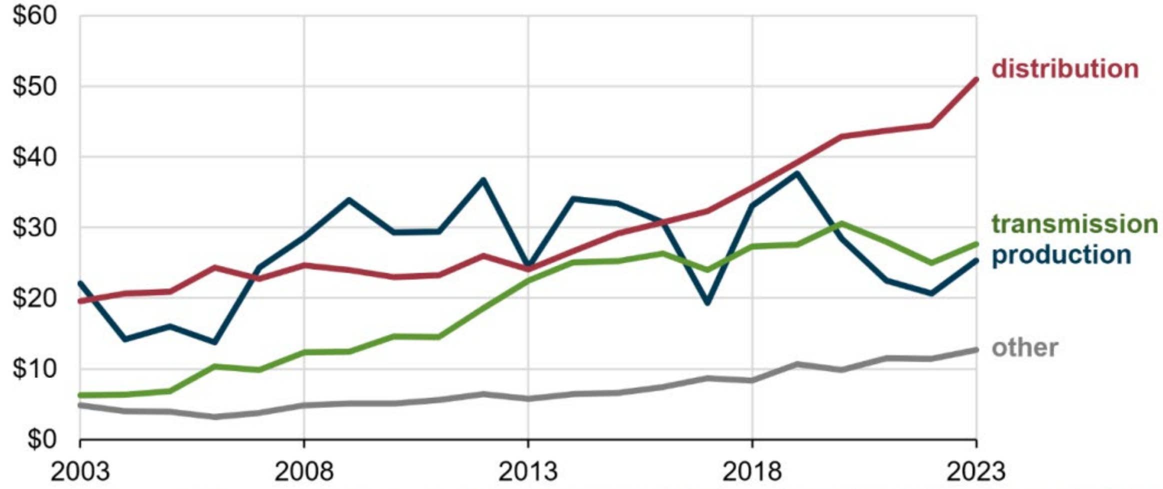
FIGURE 1: FORECASTED GROWTH OF US ELECTRIC ENERGY DEMAND (TWH/YR)



Source: The Brattle Group, based on an aggregation of individual regional transmission organizations (RTOs) and independent system operators (ISOs) and utilities' most recent forecasts.

Load is projected to grow 50% in the next decade … at a time when capex has already been increasing even in inflation-adjusted terms and even before the emergence of this load growth

FIGURE 2: ANNUAL US CAPITAL ADDITIONS BY SECTOR (2003–2023)
(2023 $billions)



Source: US Energy Information Administration (EIA) (2024), *Grid infrastructure investments drive increase in utility spending over last two decades*. Data sourced from US EIA and FERC financial reports as accessed by Ventyx Velocity Suite.

How to Support Load Growth and Policy Goals Quickly and Efficiently

I. Maximize the Value of Existing Power System

III. Implement Proactive Planning & Procurement

II. Cost-Effectively Accelerate New Grid Connections

IV. Introduce Targeted Affordability Measures

For each of these key areas, the full report offers case studies, cross references to industry experience and commercially-available technologies, and a discussion of best practices.

Success Will Require Coordination & Collaboration among Key Stakeholders

SOLUTION	REGULATORS	UTILITIES	GRID PLANNERS /OPERATORS	GOVERNORS LEGISLATORS	OTHERS
I. Maximize the Value of Existing Power System	☑	☑	☑	☑	Third-party DER aggregators
II. Cost-Effectively Accelerate New Grid Connections	☑	☑	☑	☑	Energy park developers
III. Implement Proactive Planning & Procurement	☑	☑	☑	☑	Power procurement authorities; state energy offices
IV. Introduce Targeted Affordability Measures	☑	☑		☑	State energy offices

(See more detailed table in Executive Summary of our July 2025 report.)

Transmission options for more cost-effective, affordable outcomes

Achieving cost-effective transmission-planning outcomes requires a multi-faceted approach:

1. More **proactive and comprehensive transmission planning** (as mandated by Order 1920)
   - Multi-driver/value planning (incl. for generator interconnection) to find lowest-total-cost solutions
   - Least regrets planning to mitigate risk and costs of both overbuilding and undersizing
2. "**Loading order**" for transmission planning that prioritizes lower cost/impact options
   - Optimize existing grid → upsize existing lines → add new lines
3. **Cost control incentives**
   - Soft/hard cost caps, broad-based PBR, or targeted incentives (such as shared savings/overruns)
4. **Competitive solicitations**
   - Where possible and practical; with added cost-control incentives
5. **End-use efficiency and demand flexibility**
   - To reduce transmission, distribution, generation, and resource-adequacy costs

(See our NESCO slides: Ensuring Cost-Effective Transmission in Support of a Clean Energy Transition, Aug 2024)

We need to double or triple US transmission capability … and can do at least some of it quickly and cost-effectively!

1. Advanced, grid enhancing technologies

- Dynamic line ratings
- Flow control devices
- Topology optimization
- Grid-optimized DER/storage
- Remedial action schemes
- Grid-forming inverters

2. Upgrades of existing lines

- Advanced conductors
- Rebuild aging lines at higher voltage
- Conversions to HVDC

3. New transmission

- Highway/railroad corridors
- ROW-efficient AC designs
- HVDC transmission
- Submarine/undergound
- New greenfield overhead

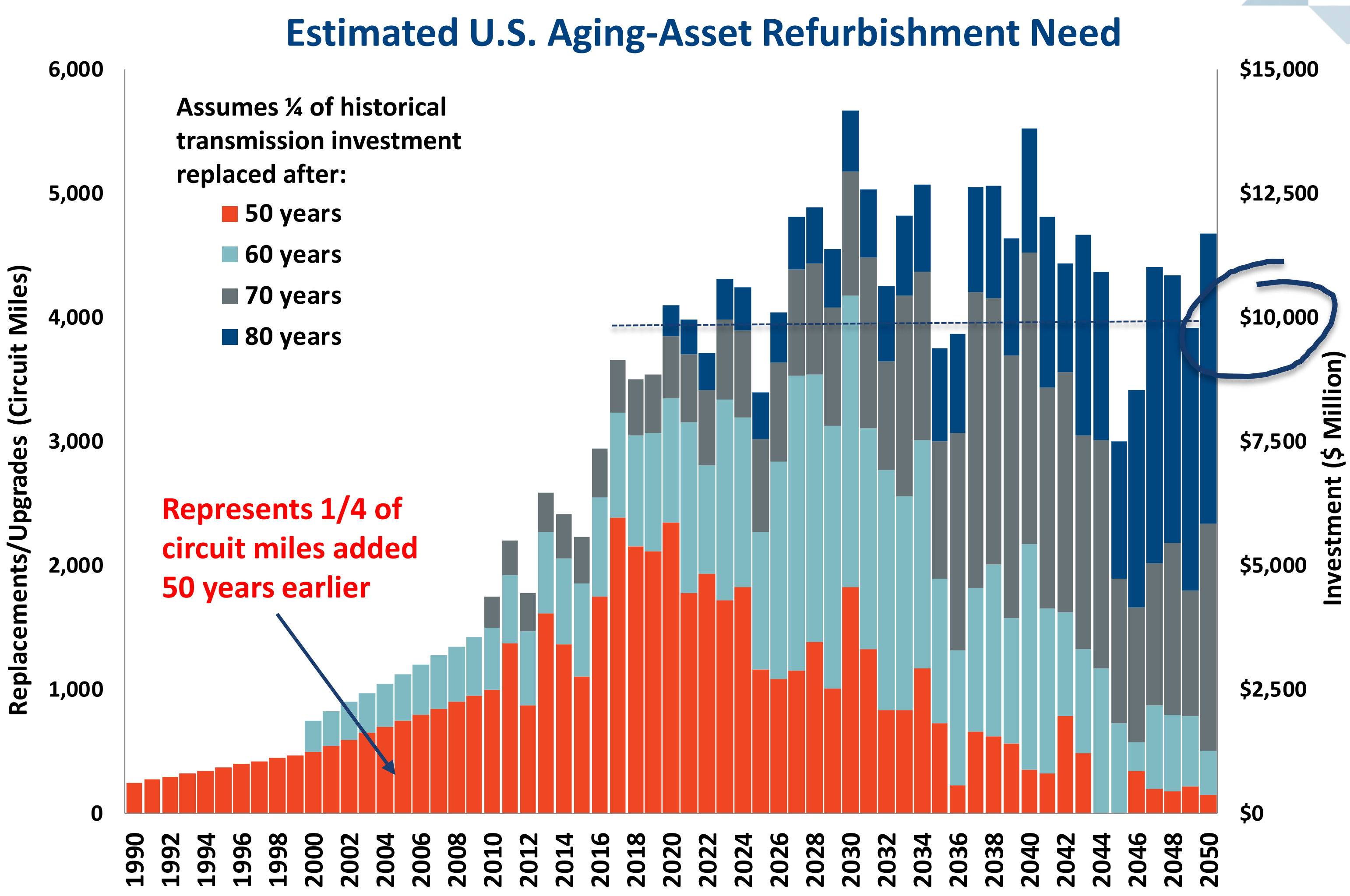
Examples:

Priority order required by the German "NOVA Principle"

MA CETWG Report: "Loading Order" and ATT/GETs recommendations

Refurbishment of the aging US grid = Opportunities to upsize

- Much of today's grid was built in the 1960s and 70s
- Facilities that need to be replaced after 50 to 80 years, now likely account for at least $10 billion in annual transmission investment
- Has reached 80% of total in some regions, such as PJM
- Some of these replacements are on highly-valuable right of way that could be used to "upsize" new facilities in cost-effective support of public policy goals



Source: Brattle estimate. Assumes $2.5 million per refurbished circuit mile

Transmission planning is too siloed and reliability-focused

Local TO Reliability Projects
Upgrades to meet local standards

Generator Interconnection (GI) Projects
Reliability upgrades for GI requests

Long Term Transmission Service Projects
Reliability upgrades for Tx Service Requests

Regional Reliability Projects
Addresses remaining reliability needs

Regional Economic & Public Policy Projects
Often addresses only a narrow set of remaining needs

Joint RTO *Interregional* Planning Processes
View of remaining needs is often narrow, resulting in few to no projects

More consolidated, comprehensive, proactive planning is needed to achieve cost-effective planning outcomes

These solely reliability-driven processes account for > 90% of all U.S. transmission investments

- None involve any assessments of economic benefits (i.e., cost savings offered by the new transmission)

Incremental generation interconnection has become the primary tool (and efficiency barrier) to support public policy goals

Planning for economic & public-policy needs results in less than 10% of all U.S. transmission investments

Interregional planning processes are large ineffective

- Essentially no major interregional transmission projects have been planned and built in the last decade
- Numerous national studies show that more interregional transmission is needed to reduce total system costs

See: DeLosa, Pfeifenberger, Joskow, Regulation of Access, Pricing, and Planning of High Voltage Transmission in the US, MIT-CEEPR, March 7, 2024.

Options for interconnecting generation more quickly and efficiently

With FERC Order 2023 guidance and emerging best practices from other regions, the following measures can add resources more quickly and cost-effectively:

1. Implement fast-track process for sharing and transfers of existing POIs
2. Identify existing "headroom" at possible POIs
3. Fast-track new POIs for "first-ready" projects
4. Allow for GETs and (simple) RAS/SPS to address interconnection needs
5. Simplify ERIS (energy-only) interconnections with option to upgrade to NRIS (capacity) later
6. Proactively and holistically plan for long-term transmission needs
7. Speed up state & local permitting for projects with signed interconnection service agreements (PJM blog: 44+ GW with ISAs yet only 2 GW brought online in 2022)

For more detail, see How Resources Can Be Added More Quickly and Effectively to PJM's Grid, OPSI Annual Meeting, October 17, 2023.

More holistic transmission planning is needed!

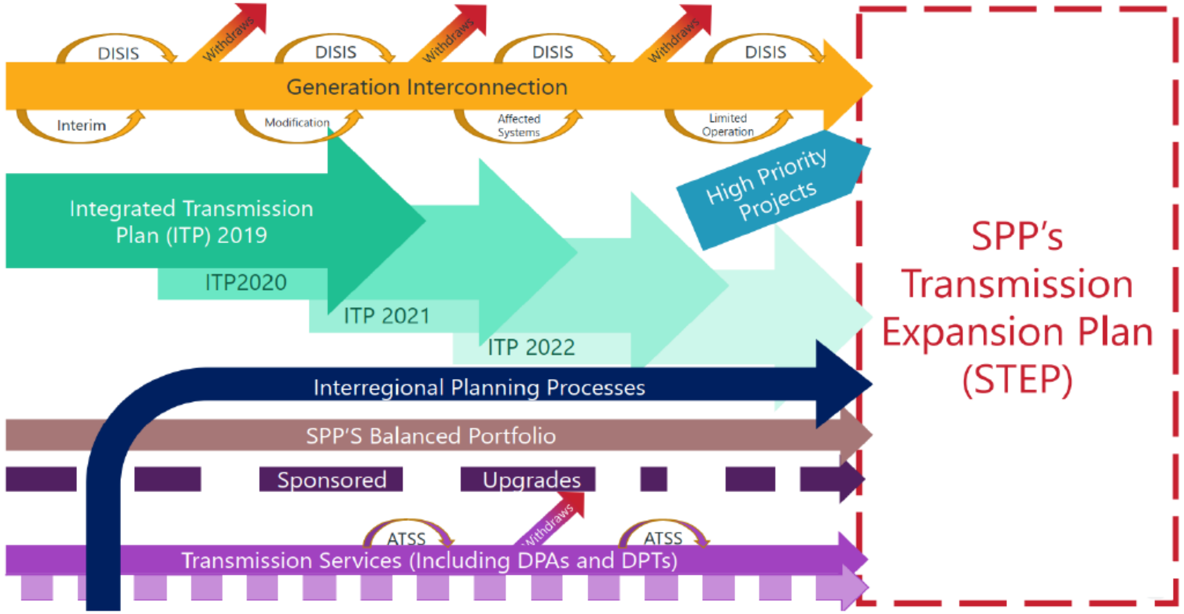
Improved transmission planning processes offer significant benefits (and overall cost savings) if they:

1. Comprehensively consider all transmission needs over longer time frames (i.e., consolidate planning for two+ decades of already- known or likely needs for generator interconnection, local and regional reliability, economic benefits, and public policies, as opposed to need at a time)
2. Use proactive, multi-value planning processes to address both urgent near-term needs and long-term needs, utilizing scenario-based, least-regrets planning to explicitly address uncertainties
3. Reduce the scope of network upgrades triggered by generator interconnection through the proactive planning process (and improve generator interconnection study criteria)
4. Look beyond regional seams to identify more cost-effective interregional solutions to the range of identified transmission needs
5. Rely on advanced transmission technologies, upsizing opportunities, and flexible solutions to address identified needs and enhance the grid
6. Utilize pragmatic cost allocations that are roughly commensurate with (but not formulaically based on) benefits received

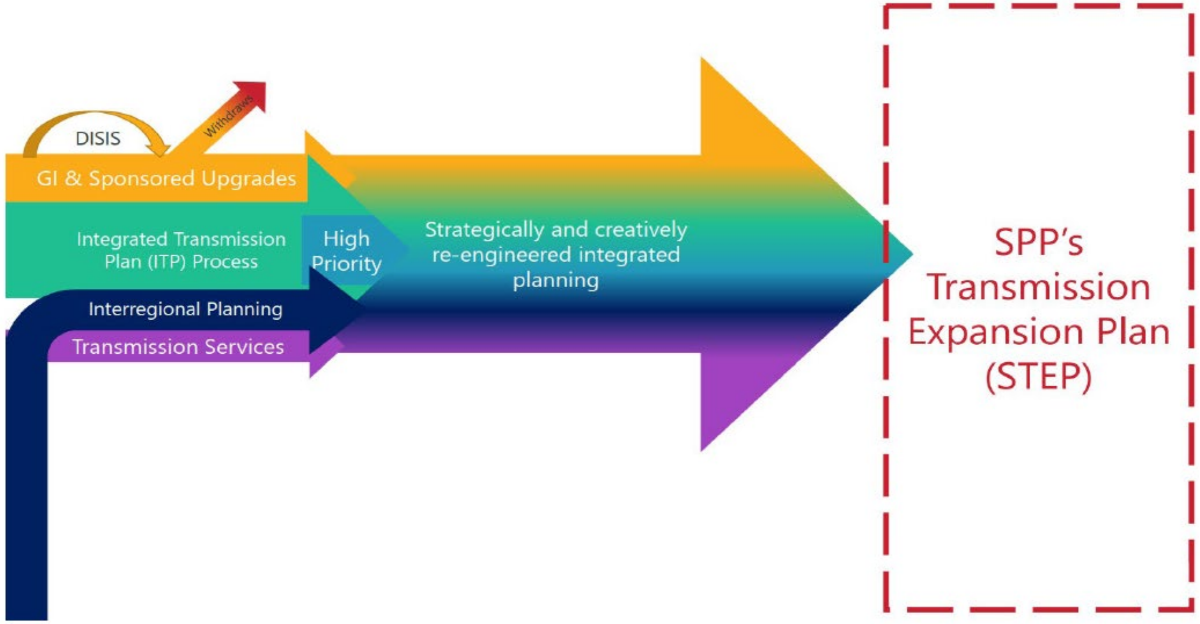
Example: SPP's proposed Consolidated Planning Process (CPP)

The Southwest Power Pool (SPP) is working on consolidating siloed planning processes (e.g., for generator interconnection, integrated regional transmission, transmission service requests, and interregional planning) into a single comprehensive process:

Current Planning Process



Proposed Consolidated Planning Process



Source: SPP, Strategic and Creative Re-Engineering of Integrated Planning Team (SCRIPT), CPP Task Force, Dec 13, 2021

FERC's Order 1920 leaves room for further improvements

Order 1920 compliance offers opportunities to improve transmission planning processes beyond the Order's mandated minimum requirements:

1. Better deal with long-term uncertainties through proactive **scenario-based planning**
2. Use best-practice experience for benefit quantification
3. Consolidate siloed planning processes
4. Employ **least-regrets** planning criteria to minimize the risk of both over-building and under-sizing
5. Develop more **flexible** solutions
6. Get more out of the existing grid, focus on cost effectiveness, and include cost-control incentives
7. Explicitly consider interregional solutions to regional needs

Key planning tools for an uncertain future

(beyond transmission):

- Scenario based
- Flexible, least-regrets solutions

For more detail, see Integrated System Planning under Uncertainty, September 23, 2025.

Risk mitigation through “least-regrets” planning

The concept of “least-regrets” planning is widely popular but poorly understood. What is it?

Should least-regrets planning identify resource and grid plans that offer:

1. The lowest transmission cost for the chosen “reference/base-case” scenario (least-cost planning)?
2. The lowest total system costs (G+T+reliability costs) for the reference/base-case scenario?
3. Investments needed only for the least challenging scenario (to avoid building too much)?
4. Sufficient capacity to handle even the most challenging scenario (to avoid being “caught short”)?
5. The lowest average cost (highest average benefits) across all scenarios (i.e., best probability-weighted outcome)?
6. The lowest “cost of being wrong” across all scenarios (i.e., minimize risk)?
7. The best combination of (5) and (6)?

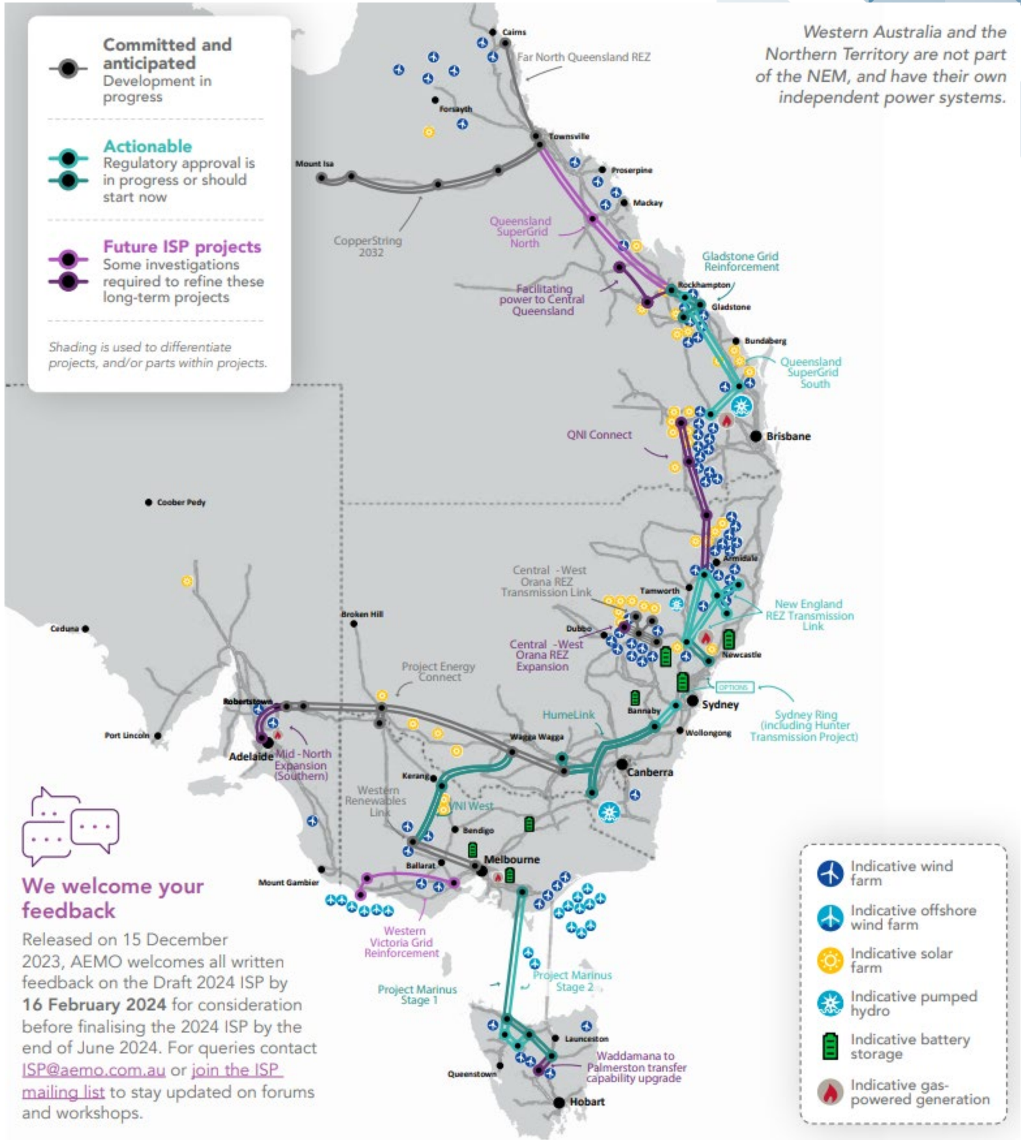
This is what least-regrets planning should focus on!

Example: AEMO least-regrets framework used in its Integrated System Plan (ISP)

Example: Australian Integrated System Plan (ISP)

The Australian Energy Market Operator (AEMO) integrated planning process is “best in class” for proactive, scenario-based, least-regrets planning:

- Clearly-specified methodology (link) produces updated plans every two years with extensive stakeholder consultations (see Draft 2024 ISP)
  - Scenario-based analysis explicitly considers long-term uncertainties and risk mitigation over next 30 years (link)
  - Plans distinguish: (1) actionable projects for which the need is certain enough now to move forward; and (2) future projects that are likely needed at some point
  - Least regrets planning values optionality that can be exercised if/when needed (e.g., projects that can be built/expanded in stages; or undertaking “early works” to develop shovel-ready projects that can be constructed quickly in the future)
- Guidelines for cost-benefit framework, forecasting, and “investment tests” from the Australian Energy Regulator (AER) make AEMO plans actionable (link)

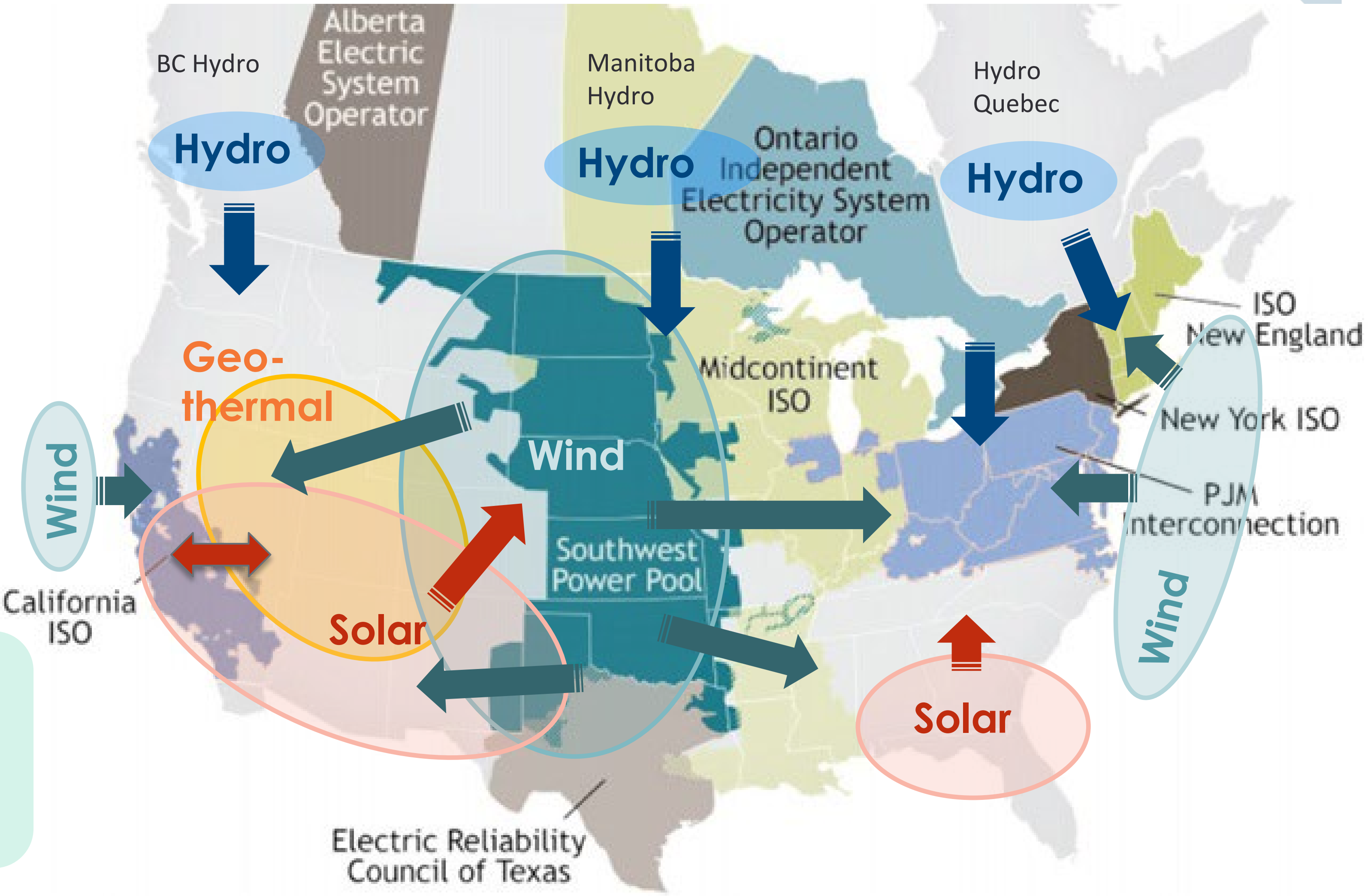


Source: AEMO | Draft 2024 ISP Consultation

More interregional transmission will be beneficial to access and diversify load and generation

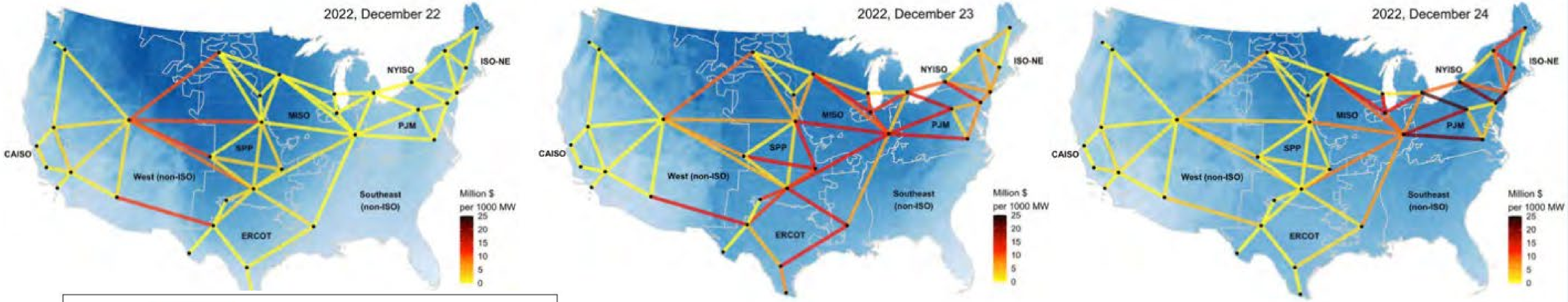
Beyond providing access to low-cost resources, grid-based resource diversification offers increasingly significant benefits:

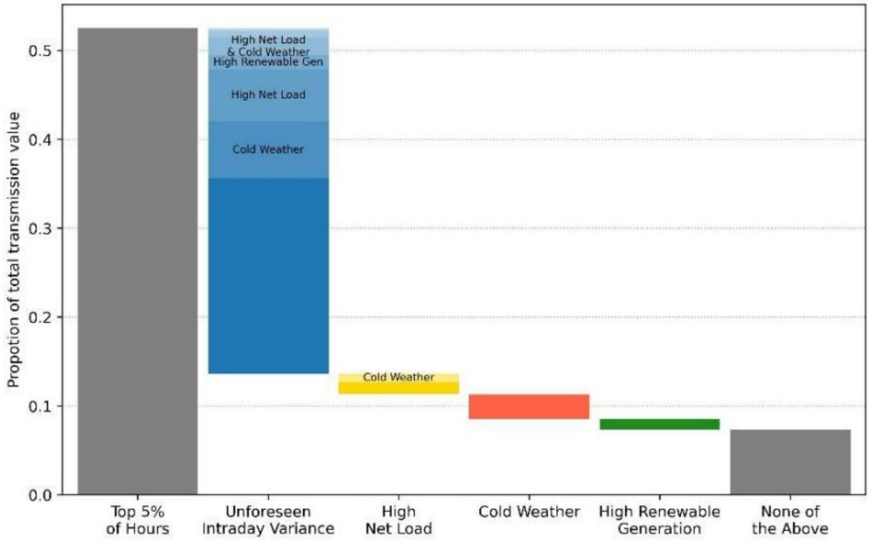
- Regional diversification of resources and customers' electricity usage reduces the investment and balancing cost
- Diversity of resources and load increases the value of transmission between them
- **To take advantage of this diversity value the grid needs to be be larger than the size of large weather systems**



Unrealized Value of Interregional Transmission Exceeds Costs

Interregional transmission is highly valuable, during challenging and extreme events. Example: **Winterstorm Elliot** (2022)



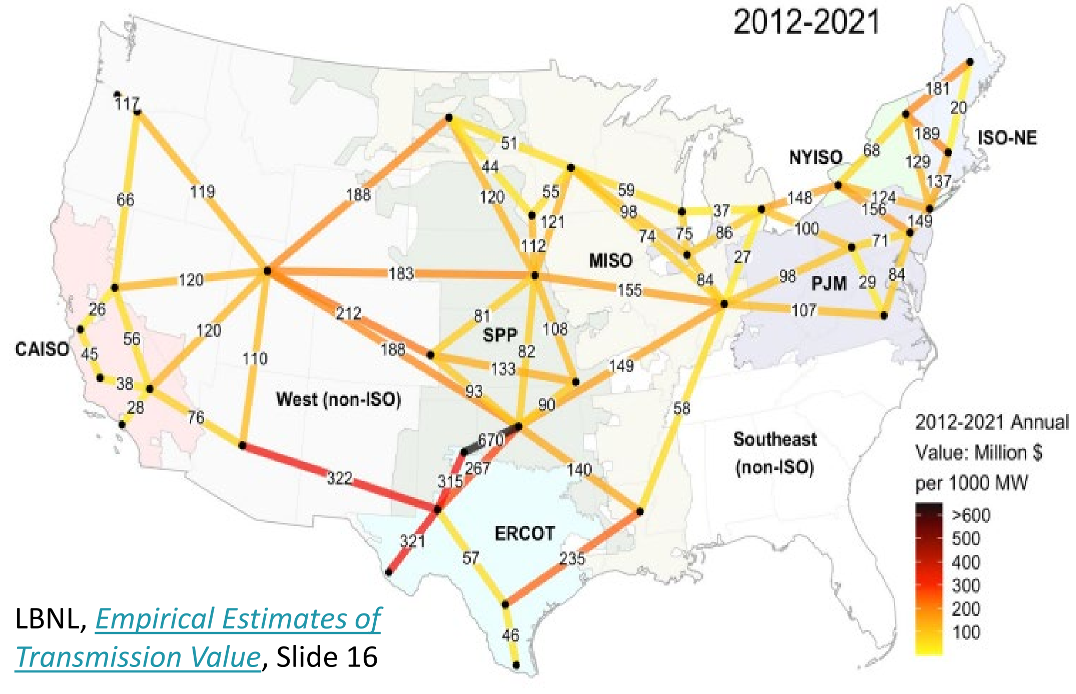


Findings:

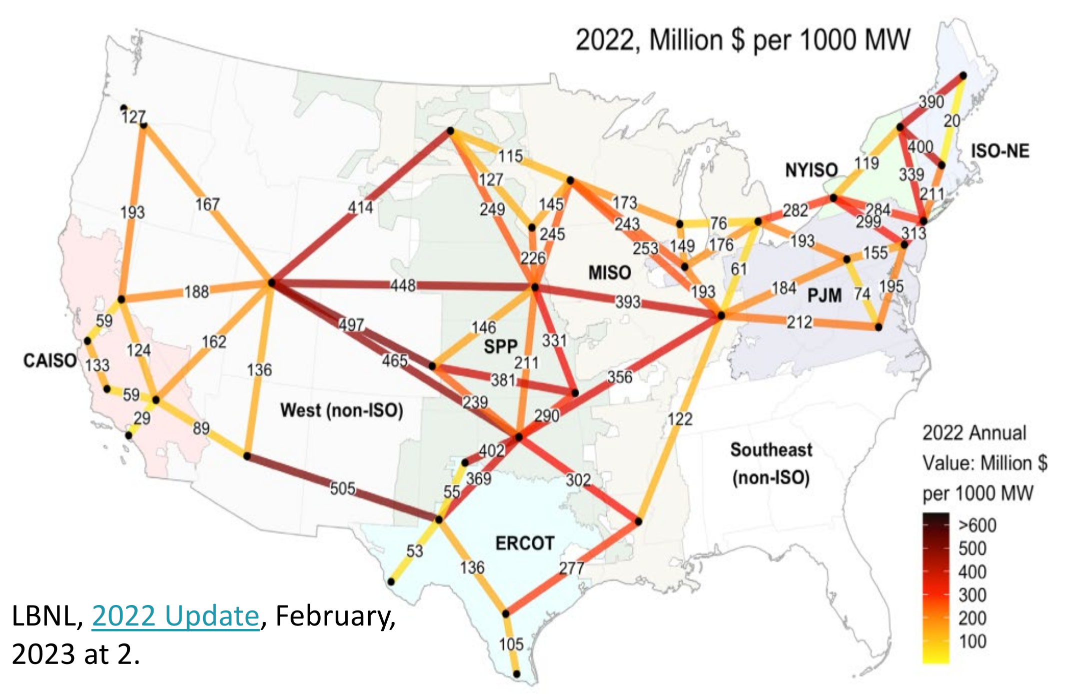
- **Benefits are estimated to exceed costs of transmission expansion**
- Most of that value is due to unpredictable real-time market conditions that are not foreseeable even on a day-ahead basis

Sources: LBNL, Transmission Value Manuscript NatureEnergy (March 29, 2024); Department of Energy's 2023 National Transmission Needs Study (Oct 2023)

LBNL: High Value of Interregional Transmission (2012-2022)



LBNL, *[Empirical Estimates of Transmission Value]*, Slide 16



LBNL, [2022 Update], February, 2023 at 2.

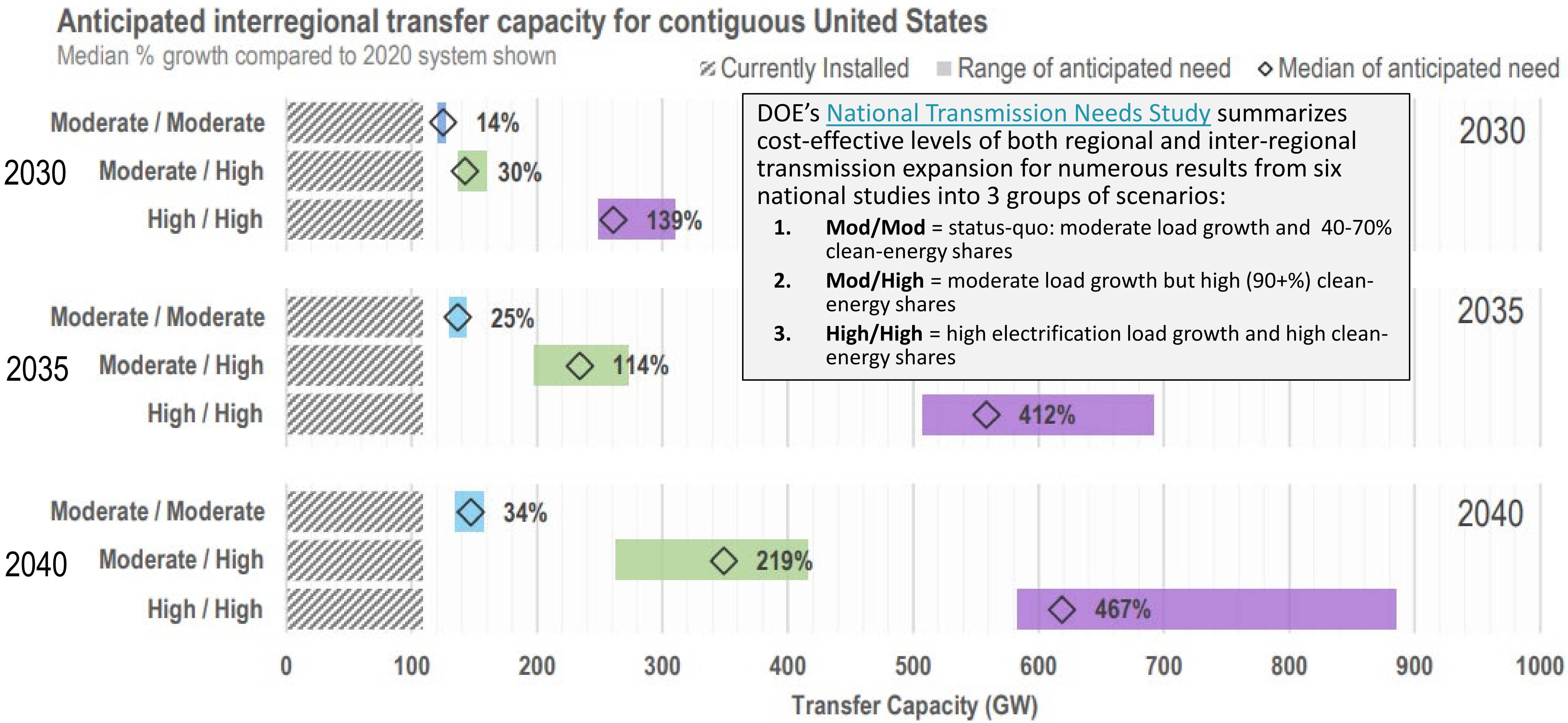
Sources: [LBNL, Empirical Estimates of Tx. Value] (Aug 2022), Slide 16; [The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade], Fact Sheet, LBNL (Feb 2023) at 2.

Methodology: Transmission value based on historical real-time price difference between regional nodes

Study Findings:

- Interregional links have greater value than regional links
- The value in some of the recent years (e.g., 2021, 2022) is double the 10-year average
- Insurance against extremes: 40-80% of transmission value occurs in top 5% of hours due to challenging system conditions; 20-30% from top 1% of hours reflecting the high impact of extreme conditions

DOE's 2023 Transmission Needs Study: Interregional Needs



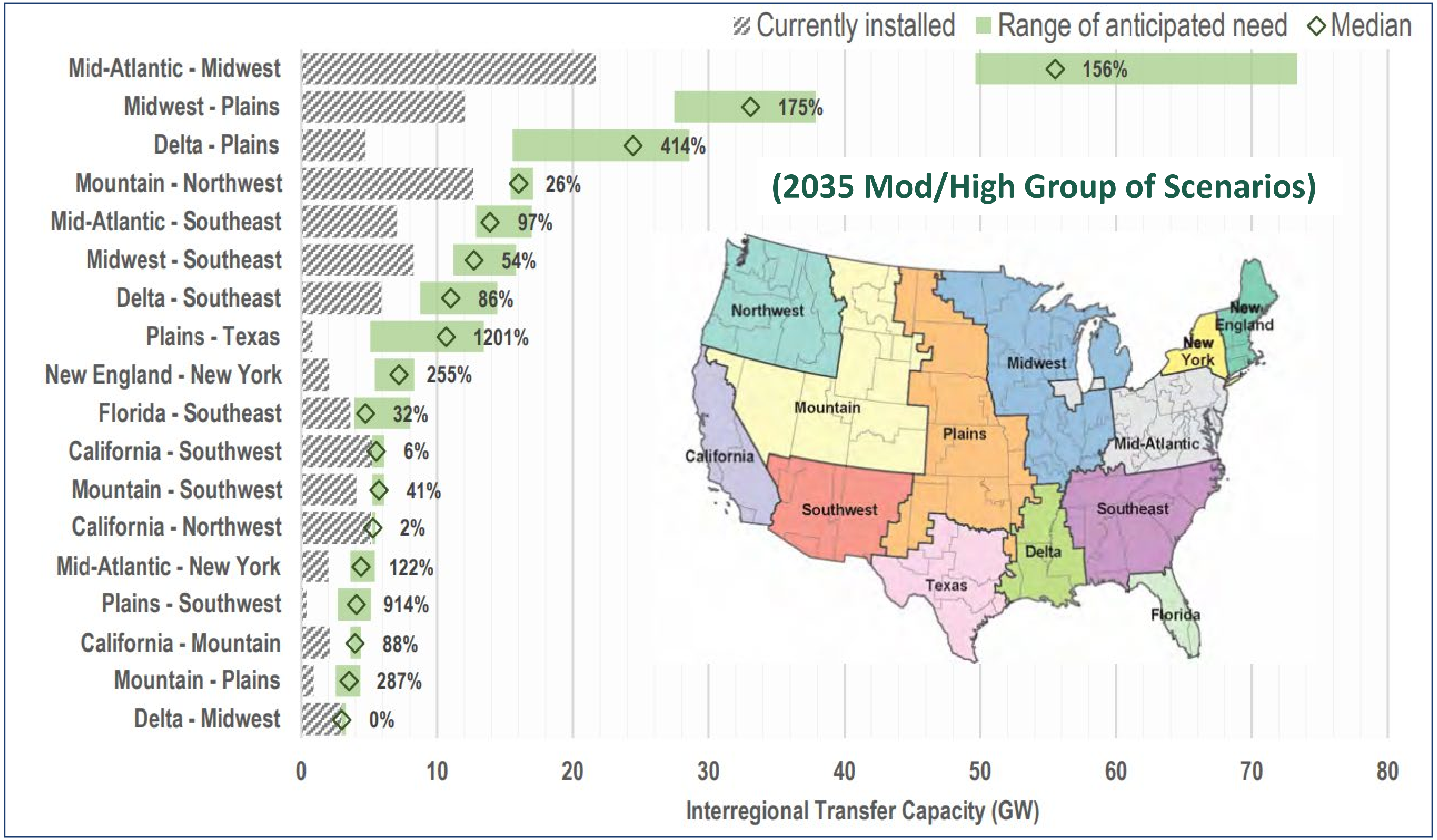
DOE's National Transmission Needs Study summarizes cost-effective levels of both regional and inter-regional transmission expansion for numerous results from six national studies into 3 groups of scenarios:

1. **Mod/Mod** = status-quo: moderate load growth and 40-70% clean-energy shares
2. **Mod/High** = moderate load growth but high (90+%) clean-energy shares
3. **High/High** = high electrification load growth and high clean-energy shares

Source: DOE, National Transmission Needs Study, October 2023 (report) and Department of Energy's 2023 National Transmission Needs Study (slides)

Note: Expansion options include enhancing the existing grid & existing ROW plus new transmission lines

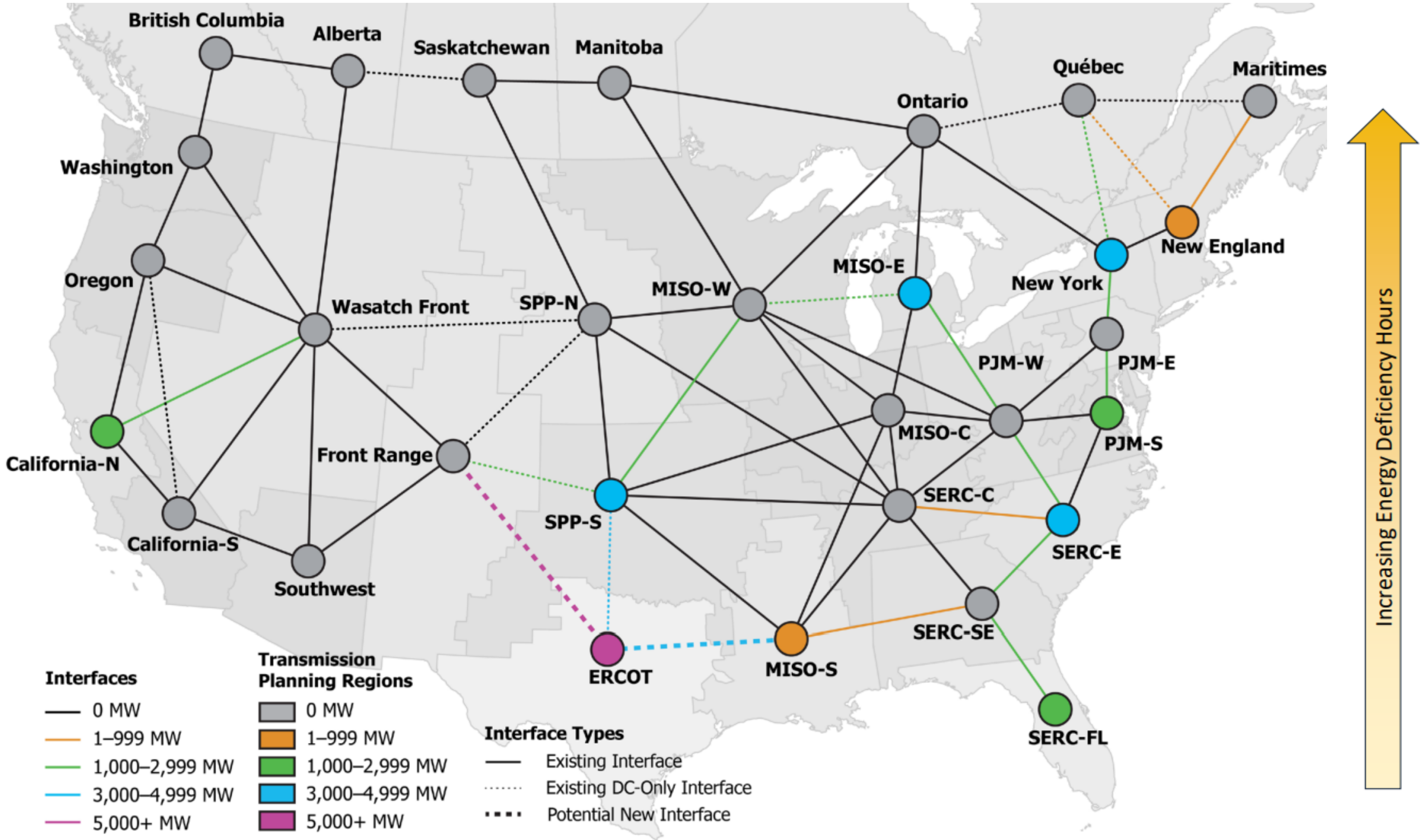
DOE's 2023 Transmission Needs Study: 2035 Interregional Needs



Source: DOE, [National Transmission Needs Study], October 2023 (report) and [Department of Energy's 2023 National Transmission Needs Study] (slides)

Note: Expansion options include enhancing the existing grid & existing ROW plus new transmission lines

NERC (ITCS, 2024): “Prudent” Expansions (by 2033, based on reliability only)



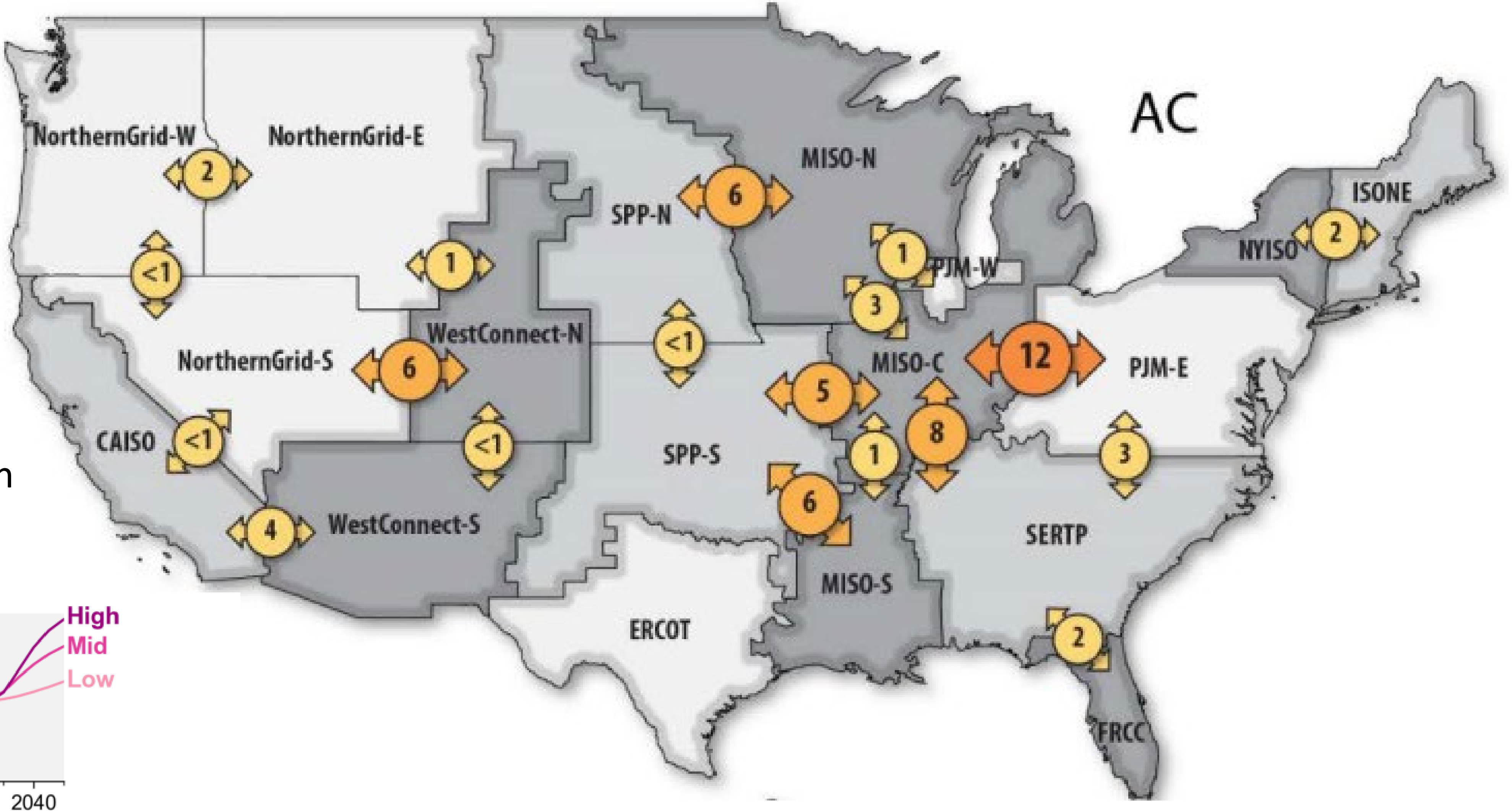
Transmission Planning Region	Additional Transfer Capability (MW)	Interface Additions (MW)
ERCOT	14,100	Front Range (5,700) MISO-S (4,300) SPP-S (4,100)
MISO-E	3,000	MISO-W (2,000) PJM-W (1,000)
New York	3,700	PJM-E (1,800) Québec (1,900)
SPP-S	3,700	Front Range (1,200) ERCOT (800) MISO-W (1,700)
PJM-S	2,800	PJM-E (2,800)
California North	1,100	Wasatch Front (1,100)
SERC-E	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	1,200	SERC-SE (1,200)
New England	700	Québec (400) Maritimes (300)
MISO-S	600	ERCOT (300) SERC-SE (300)
TOTAL	35,000	

Source: Interregional Transfer Capability Study (ITCS) - Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)

DOE National Transmission Planning Study (NTPS, 2024)

GW of "High-opportunity" interregional transmission expansion by 2035

(Conservative estimates based on "central" scenario)



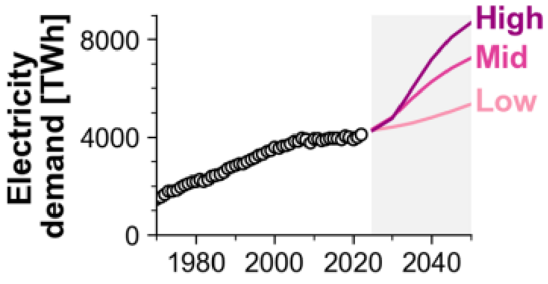


Figure 5. Annual demand assumptions for the contiguous United States

Historical demand shown is electricity sales to ultimate customers from EIA (2024b).

Source: [DOE National Transmission Planning Study]

DOE's 2024 NTPS confirms significant future transmission needs

DOE's National Transmission Planning Study (NTPS) finds that:

1. The lowest-cost U.S. electricity system that can **reliably meet future demand** includes substantial **local, regional, and interregional** transmission expansion
   - To achieve the most cost-effective outcomes, the nation's **transmission capacity would have to expand 50-100% by 2035** and **2.4-4.1 times by 2050** at a cost of $760 billion to $1.4 trillion
   - If well-planned, approximately **$1.60 to $1.80 is saved for every dollar spent** on transmission
2. Multi-state and interregional coordination, using both existing and new local, regional, and interregional transmission, can **save $270 billion to $1 trillion through 2050**
   - The largest savings come from (1) coordinating resource adequacy and (2) expanding interregional transmission to exceed 30% of most regions' peak load
3. To achieve these outcomes, the **consolidation of siloed planning processes** is critical
   - Planning needs to consider extreme events, technology advancements, and demand uncertainty
   - Better interregional coordination is needed to efficiently utilize interregional transmission

Source: Department of Energy, Grid Deployment Office, National Transmission Planning Study, 2024.

Limitations of National Studies

Although existing many studies demonstrate the benefits of transmission expansion, they have not been successful motivating actual transmission project developments. The reasons include some or all of the following:

- Some studies **analyze aspirational targets or scenarios that do not reflect the actual policies and mandates** applicable for the next 10-15 years
  - This makes it difficult demonstrate a compelling “need” to policy makers, regulators, and permitting agencies
- The studies are **not transmission planning studies**: they often do not identify specific transmission projects and do not connect with RTO planning processes and needs identification
- Studies **do not to identify how benefits and costs are distributed** across utility service areas, states, or RTO/ISO under different scenarios, as would be necessary to gain broad support and develop feasible cost allocations
  - The studies typically do not consider or propose how to recover (“allocate”) transmission costs
- There has not been **an analysis of the state-by-state economic impact and job creation** from interregional transmission development, reduction in electricity prices, and shifts in the locations of clean-energy investment
- Most studies do not address the many barriers to planning processes and to the permitting/development of specific interregional transmission projects

Survey: Barriers to Interregional Transmission

A. Leadership, Alignment and Understanding	1. Insufficient leadership from RTOs and federal & state policy makers to prioritize interregional planning 2. Limited trust amongst states, RTOs, utilities, & customers 3. Limited understanding of transmission issues, benefits & proposed solutions 4. Misaligned interests of RTOs, TOs, generators & policymakers 5. States prioritize local interests, such as development of in-state renewables
B. Planning Process and Analytics	**6. Benefit analyses are too narrow, and often not consistent between regions** 7. Lack of proactive planning for a full range of future scenarios **8. Sequencing of local, regional, and interregional planning** 9. Cost allocation (often too contentious or overly formulaic)
C. Regulatory Constraints	10. Overly-prescriptive tariffs and joint operating agreements 11. State need certification, permitting, and siting

Source: The Brattle Group. Appendix A of A Roadmap to Improved Interregional Transmission Planning, November 30, 2021. Based on interviews with 18 organizations representing state and federal policy makers, state and federal regulators, transmission planners, transmission developers, industry groups, environmental groups, and large customers.

Seams still prevent efficient use of interregional transmission

Significant seams-related inefficiencies exist between RTO markets (and other regions) that prevent us from effectively planning and taking full advantage of (existing and new) interregional transmission infrastructure:

1. **Interregional transmission planning** is ineffective
2. **Generator interconnection** delays and cost uncertainty created by affected system impact studies (and effectiveness coordination through means such as the SPP-MISO JTIQ, reducing costs by 50%)
3. **Loop flow management** inefficiencies through market-to-market coordinated flowgates (with shares of firm flow entitlements) under the existing JOAs
4. **Inefficient trading** across contract-path market seams and the need for intertie optimization*
5. **Resource adequacy** value of interties (often not considered in RTO's resource adequacy evaluations) and barriers to capacity trades (often created by RTOs' restrictive capacity import requirements and incompatible resource accreditations)

* See Intertie Optimization: Achieving Efficient Use of Interregional Transmission, IEEE PES Energy and Policy Forum, April 2025.

The Bottom Line: Necessary Improvements

Proactive and comprehensive transmission planning

- More cost-effective solutions (that integrate generator interconnection, asset refurbishment, and all other transmission needs) can be identified
- The costs and time required to address future transmission needs (and interconnect the large number of resources necessary to meet clean-energy goals) can be reduced dramatically
- More flexible plans can be developed to address the wide range of uncertain long-term needs

The benefits of comprehensive proactive planning increase for processes that:

1. Consider both <u>near- and long-term transmission needs</u> (i.e., at least a decade of already known resource needs, as opposed to addressing only near-term needs without considering long-term needs)
2. Simultaneously considers <u>multiple needs</u> (generator interconnection, local and regional reliability, economic benefits, and public policy needs)
3. Reduce network upgrades triggered by generator interconnection <u>proactive and comprehensive planning</u>
4. Look <u>beyond regional seams</u> to identify more cost-effective <u>interregional</u> solutions to the range of identified transmission needs
5. Rely on <u>advanced transmission technologies</u> and <u>upsizing of existing lines</u> to address some of the identified needs
6. Utilize <u>pragmatic cost allocations</u> that are roughly commensurate with (not formulaically based on) benefits received

Thank You!

About the Speakers

Johannes P. Pfeifenberger

PRINCIPAL
THE BRATTLE GROUP, BOSTON

Hannes.pfeifenberger@brattle.com

+1.617.234.5624

(webbio and publications)

Johannes (Hannes) Pfeifenberger, a Principal at The Brattle Group, is an economist with a background in electrical engineering and over twenty-five years of experience in wholesale power market design, renewable energy, electricity storage, and transmission. He is a Visiting Scholar at MIT's Center for Energy and Environmental Policy Research (CEEPR), a former Senior Fellow at Boston University's Institute of Sustainable Energy (BU-ISE), an IEEE Senior Member, and currently serves as an advisor to research initiatives by the US Department of Energy, the National Labs, and the Energy Systems Integration Group (ESIG).

Mr. Pfeifenberger specializes in wholesale power markets and transmission. He has analyzed transmission needs, transmission benefits and costs, transmission cost allocations, and renewable generation interconnection challenges for independent system operators, transmission companies, generation developers, public power companies, industry groups, and regulatory agencies across North America. He has worked on transmission matters in SPP, MISO, PJM, New York, New England, ERCOT, CAISO, WECC, and Canada and has analyzed offshore-wind transmission challenges in New York, New England, and New Jersey.

He received an M.A. in Economics and Finance from Brandeis University's International Business School and an M.S. and B.S. ("Diplom Ingenieur") in Power Engineering and Energy Economics from the University of Technology in Vienna, Austria.

Summary of Interregional Transmission Studies

Study	Years analyzed	Considerations/assumptions	Findings
1. DOE 2023 Transmission Needs Study	2030, 2035, 2040	Reviewed of 300 scenarios and sensitivities from 6 independent national transmission studies. Almost all have decarbonization constraints (in addition to BAU scenarios)	Range of additional transmission needs in 2040 from moderate to high decarbonization: **SPP-MISO:** 3.6-98.7 GW **MISO-PJM:** 2.7-119 GW **PJM-SERTP:** 1.5-12.5 GW **ERCOT-SPP:** 0.9-34.9 GW **SERTP-FRCC:** 0-12.9 GW **CAISO-WestConnect:** 0.2-6.9 GW WestConnect-Rockies: 0.4-6.1 GW SPP-SERTP: 0-37.7 GW
2. DOE 2024 National Transmission Planning Study	2035, 2040, 2050	Conducted zonal capacity expansion & resource adequacy modelling through 2050 under 96 scenarios covering different transmission frameworks (AC, P2P HVDC & meshed HVDC), decarbonization assumptions, load growth assumptions, and 15 sensitivity cases	Range of additional transmission needs in 2040 in central case: **SPP-MISO:** 10.2-17 GW **MISO-PJM:** 4.8-12 GW **PJM-SERTP:** 3.4-9.6 GW **ERCOT-SPP:** 6.2-6.7 GW, with an additional 8.3-9.1 GW of new connection from ERCOT to WestConnect **SERTP-FRCC:** 2-2.6 GW **CAISO-WestConnect:** 1.3-4 GW WestConnect-Rockies: 0-4 GW SPP-SERTP: 0-7.3 GW
3. GE-NRDC Study	2035	Uses nodal model to optimize transmission buildout by 2035 and estimate resilience benefits under severe weather events as well as production cost and capacity savings.	$12 billion in net present value from 87 GW interregional transmission (**9.7 GW between SPP-MISO, 7.4 GW between MISO-PJM, 8 GW between PJM-SERTP, and 15.1 GW between SERTP-FRCC**), including $1 billion in resilience benefits from single 2035 polar vortex event.
4. NERC ITCS	2033	Identifies "prudent" interregional transmission additions needed to maintain reliability—does not include any additional transmission justifiable based on economic and public policy benefits	**West-ERCOT:** 9.8 GW **PJM-SERTP:** 1.6 GW **SERTP-FRCC:** 1.2 GW
5. LBNL Analyses	2012–2023	Estimates congestion value (production cost savings) of expanding interregional transmission using historical data (2012-2023) on nodal marginal prices. Does not estimate transfer capability needs in GW.	**MISO-PJM:** documents historical energy market value of $98–107 million/yr per GW of transmission **ERCOT-SPP:** documents historical energy market value of $267–985 million/yr per GW of transmission **CAISO-ERCOT:** documents historical energy market value of $426–436 million/yr per GW of transmission

Examples of Brattle Reports on Regional and Interregional Transmission Planning and Benefit-Cost Analyses

Well-Planned Electric Transmission Saves Customer Costs:
Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future

PREPARED FOR
WIRES

Link: Well-Planned Transmission

PREPARED BY
Judy W. Chang
Johannes P. Pfeifenberger

May 2016

THE Brattle GROUP

Toward More Effective Transmission Planning:
Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid

PREPARED FOR
WIRES

Link: Effective Transmission Planning

PREPARED BY
Johannes P. Pfeifenberger
Judy W. Chang
Akarsh Sheilendranath

April 2015

The Brattle Group

Link: Transmission Benefits

The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments

July 2013

Judy W. Chang
Johannes P. Pfeifenberger
J. Michael Hagerty

Link: Diversity Value

BU
Boston University Institute for Sustainable Energy

The Value of Diversifying Uncertain Renewable Generation through the Transmission System

September • 2020

A Roadmap to Improved Interregional Transmission Planning

Link: Interregional Roadmap

PREPARED BY
Johannes P. Pfeifenberger
Kasparas Spokas
J. Michael Hagerty
John Tsoukalis

November 30, 2021

Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs

Link: Brattle Grid Strategies

PREPARED BY

The Brattle Group:
Johannes Pfeifenberger
Kasparas Spokas
J. Michael Hagerty
John Tsoukalis

Grid Strategies:
Rob Gramlich
Michael Goggin
Jay Caspary
Jesse Schneider

OCTOBER 2021

Brattle
GRID STRATEGIES LLC

Summarizes proven approaches to quantifying various benefits

Brattle Group Publications on Transmission

Pfeifenberger, Integrated System Planning under Uncertainty, LSI Electric Power Conference, September 23, 2025.
Pfeifenberger, et al., Optimizing Grid Infrastructure and Proactive Planning to Support Load Growth and Public Policy Goals, prepared for Clean Air Task Force, July 2025.
Tsuchida, et al., Incorporating GETs and HPCs into Transmission Planning Under FERC Order 1920, prepared for ACORE, April 2025.
Pfeifenberger, et al., Proposal to Develop Optimal Transmission Planning in Alberta, prepared for AESO, April 2025.
Pfeifenberger, "Intertie Optimization: Achieving Efficient Use of Interregional Transmission,“ IEEE PES Energy and Policy Forum, April 2025.
DeLosa, et al., Strategic Action Plan, prepared for the Northeast States Collaborative on Interregional Transmission, April 2025.
Gramlich, Hagerty, et al., Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid, Grid Strategy and Brattle, August 2024.
DeLosa, Pfeifenberger, Joskow, Regulation of Access, Pricing, and Planning of High Voltage Transmission in the US, MIT-CEEPR working paper, March 7, 2024.
Pfeifenberger, How Resources Can Be Added More Quickly and Effectively to PJM's Grid, OPSI Annual Meeting, October 17, 2023.
Pfeifenberger, Bay, et al., The Need for Intertie Optimization: Reducing Customer Costs, Improving Grid Resilience, and Encourage Interregional Transmission, October 2023.
Pfeifenberger, Plet, et al., The Operational and Market Benefits of HVDC to System Operators, for GridLab, ACORE, Clean Grid Alliance, Grid United, Pattern Energy, and Allete, September 2023.
Pfeifenberger, DeLosa, et al., The Benefit and Urgency of Planned Offshore Transmission, for ACORE, ACP, CATF, GridLab, and NRDC, January 24, 2023.
Brattle and ICC Staff, Illinois Renewable Energy Access Plan: Enabling an Equitable, Reliable, and Affordable Transition to 100% Clean Electricity for Illinois, December 2022.
Pfeifenberger et al., New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report, October 26, 2022.
Pfeifenberger, Generation Interconnection and Transmission Planning, ESIG Joint Generation Interconnection Workshop, August 9, 2022.
Pfeifenberger and DeLosa, Proactive, Scenario-Based, Multi-Value Transmission Planning, Presented at PJM Long-Term Transmission Planning Workshop, June 7, 2022.
Pfeifenberger, Planning for Generation Interconnection, Presented at ESIG Special Topic Webinar: Interconnection Study Criteria, May 31, 2022.
RENEW Northeast, A Transmission Blueprint for New England, Prepared with Borea and The Brattle Group, May 25, 2022.
Pfeifenberger, New York State and Regional Transmission Planning for Offshore Wind Generation, NYSERDA Offshore Wind Webinar, March 30, 2022.
Pfeifenberger, The Benefits of Interregional Transmission: Grid Planning for the 21st Century, US DOE National Transmission Planning Study Webinar, March 15, 2022.
Pfeifenberger, 21st Century Transmission Planning: Benefits Quantification and Cost Allocation, for NARUC members of the Joint Federal-State Task Force on Electric Transmission, January 19, 2022.
Pfeifenberger, Spokas, Hagerty, Tsoukalis, A Roadmap to Improved Interregional Transmission Planning, November 30, 2021.
Pfeifenberger, Tsoukalis, Newell, "The Benefit and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York," Prepared for NYSERDA with Siemens and Hatch, November 9, 2022.
Pfeifenberger et al., Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, Brattle-Grid Strategies, October 2021.
Pfeifenberger et al., Initial Report on the New York Power Grid Study, prepared for NYPSC, January 19, 2021.
Van Horn, Pfeifenberger, Ruiz, "The Value of Diversifying Uncertain Renewable Generation through the Transmission System," BU-ISE, October 14, 2020.
Tsuchida and Ruiz, "Innovation in Transmission Operation with Advanced Technologies," T&D World, December 19, 2019.
Pfeifenberger, "Cost Savings Offered by Competition in Electric Transmission," Power Markets Today Webinar, December 11, 2019.
Chang, Pfeifenberger, Sheilendranath, Hagerty, Levin, and Jiang, "Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value," April 2019 and "Response to Concentric Energy Advisors' Report on Competitive Transmission," August 2019.
Ruiz, "Transmission Topology Optimization: Application in Operations, Markets, and Planning Decision Making," May 2019.
Chang, Pfeifenberger, "Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future," WIRES&Brattle, June 2016.
Newell et al. "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," on behalf of NYISO and DPS Staff, September 15, 2015.
Pfeifenberger, Chang, and Sheilendranath, "Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid," WIRES and Brattle, April 2015.
Chang, Pfeifenberger, Hagerty, "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," on behalf of WIRES, July 2013.
Chang, Pfeifenberger, Newell, Tsuchida, Hagerty, "Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process," October 2013.
Pfeifenberger and Hou, "Seams Cost Allocation: A Flexible Framework to Support Interregional Transmission Planning," on behalf of SPP, April 2012.
Pfeifenberger, Hou, "Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada," on behalf of WIRES, May 2011.

Brattle Group Practices and Industries

ENERGY & UTILITIES

Competition & Market Manipulation
Distributed Energy Resources
Electric Transmission
Electricity Market Modeling & Resource Planning
Electrification & Growth Opportunities
Energy Litigation
Energy Storage
Environmental Policy, Planning and Compliance
Finance and Ratemaking
Gas/Electric Coordination
Market Design
Natural Gas & Petroleum
Nuclear
Renewable & Alternative Energy

LITIGATION

Accounting
Analysis of Market Manipulation
Antitrust/Competition
Bankruptcy & Restructuring
Big Data & Document Analytics
Commercial Damages
Environmental Litigation & Regulation
Intellectual Property
International Arbitration
International Trade
Labor & Employment
Mergers & Acquisitions Litigation
Product Liability
Securities & Finance
Tax Controversy & Transfer Pricing
Valuation
White Collar Investigations & Litigation

INDUSTRIES

Electric Power
Financial Institutions
Infrastructure
Natural Gas & Petroleum
Pharmaceuticals & Medical Devices
Telecommunications, Internet, and Media
Transportation
Water

Our Offices


BOSTON


BRUSSELS


CHICAGO


LONDON


MADRID


NEW YORK


ROME


SAN FRANCISCO


SYDNEY


TORONTO


WASHINGTON, DC

Clarity in the face of complexity

The Power of Economics™

Brattle