Regional and Interregional Transmission Planning in the Northeastern US

PREPARED BY

Johannes Pfeifenberger

PREPARED FOR

Vermont System Planning Committee

July 16, 2025

Brattle

Topics for today:

A. Interregional transmission needs in the Northeast

B. Northeast Collaborative Action Plan

C. Order 1920 opportunities to Improve Transmission Planning

D. Generator interconnection

A. Interregional Transmission Needs in the Northeast

Numerous Studies Document Significant Transmission Needs

Study	Years analyzed	Findings
1. DOE 2023 Transmission Needs Study	2030, 2035, 2040	**NY-New England:** 2035: 2.8–17 GW; 2040: 2.9–21.4 GW **NY-PJM:** 2035: 0.29–8.24 GW; 2040: 0.81–12.7 GW
2. DOE National Transmission Planning Study	2035, 2040, 2050	**NY-New England:** 1.7–2.9 GW by 2035, 3.8–6.7 GW by 2040 in central case **NY-PJM:** ~1 GW by 2040 for AC, but much higher in HVDC futures
3. DOE Atlantic OSW Transmission Study	2050	Interregional topology resulted in a **total of 14 GW of offshore transmission** between Atlantic states, with a **benefit-cost ratio of 2.9** ($2.4 billion/yr in production cost and resource adequacy benefits) [granular results on transfer capability needs between individual regions not provided].
4. GE-NRDC Study	2035	$12 billion in net present value from 87 GW interregional transmission (2 GW between NY-NE, 5 GW between NY-PJM), including $1 billion in resilience benefits from single 2035 polar vortex event.
5. MA Decarb Pathways Study	Through 2050	**NY-New England:** 0.5–4.5 GW (1.6–4.5 GW when focusing on most realistic scenarios) **NY-PJM:** 1.5–7 GW (Caveat: PJM was not explicitly modeled as its own zone but a boundary condition for New York) **QC-NY:** 3.8–6.8 GW **QC-New England:** 4.1–7.1 GW **New England-Maritimes:** 0–2.7 GW (0–0.8 GW when focusing on most realistic scenarios)

Study	Years analyzed	Findings
6. LBNL Analyses	2012–2023	**NY-New England:** documents historical energy market value of $137–189 million/yr per GW of transmission **NY-PJM:** documents historical energy market value of $149–156 million/yr per GW of transmission
7. NREL IREZ	2022	3 GW expansions from PJM to New York and New York to New England increases energy cost savings of transmission corridor by $118 million/yr and $28 million/yr, respectively (incremental costs: $27 million/yr and $21 million/yr, respectively)
8. MIT CEEPR	2050	**QC-New England:** 4 GW provides power system cost savings of $1,121 million/yr (13%) **QC-NY:** 4 GW provides power system cost savings of $913 million/yr (13%) Value is generated by utilizing the transmission bidirectionally to balance Northeast renewables, avoiding firming costs
9. NERC ITCS	2033	**NY-New England:** 0 GW (this is unlikely once considering economic and public policy benefits) **NY-PJM:** 1.8 GW to alleviate significant resource deficiencies in New York **QC-New England:** 400 MW **QC-NY:** 1.9 GW **New England-Maritimes:** 300 MW

For Study Summaries, see: Strategic Action Plan, Phase 1: Study Synthesis of Transmission Needs (Feb 2025)

DOE's 2024 NTPS confirms significant transmission needs

DOE's 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.

NE Interregional Transmission Needs (based on 9 studies reviewed)

Interregional transmission between NY, NE, and PJM is highly valuable in the near- and long-term, and low-regrets expansion opportunities should be pursued

- Cost-effective expansions between these regions are identified in numerous studies by DOE, NERC, national labs, MIT, states, and industry
- Based on these studies, we identify a **2035 low-regrets** need of **<u>2 GW between NY and PJM</u>** and **<u>1.7 GW between New York and New England</u>**
  - While uncertain, studies expect the magnitude of low-regrets expansions to increase, even without decarbonization drivers

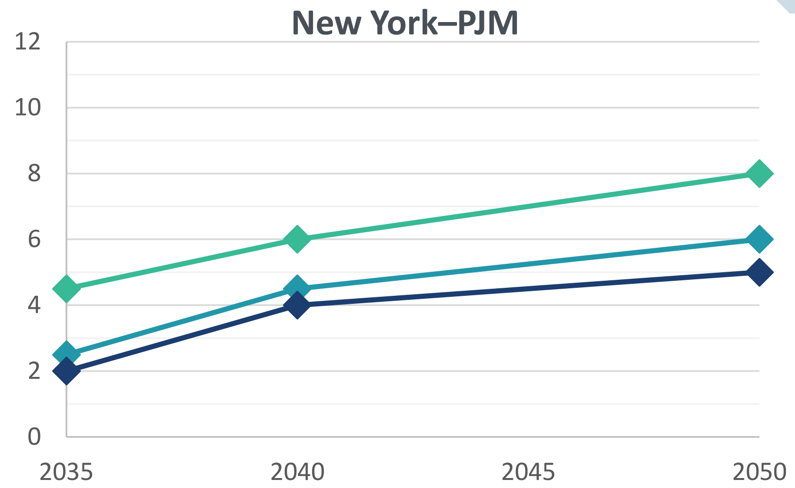
Studies also highlighted the long-term need for expansion between the <u>Northeast and Canada</u>

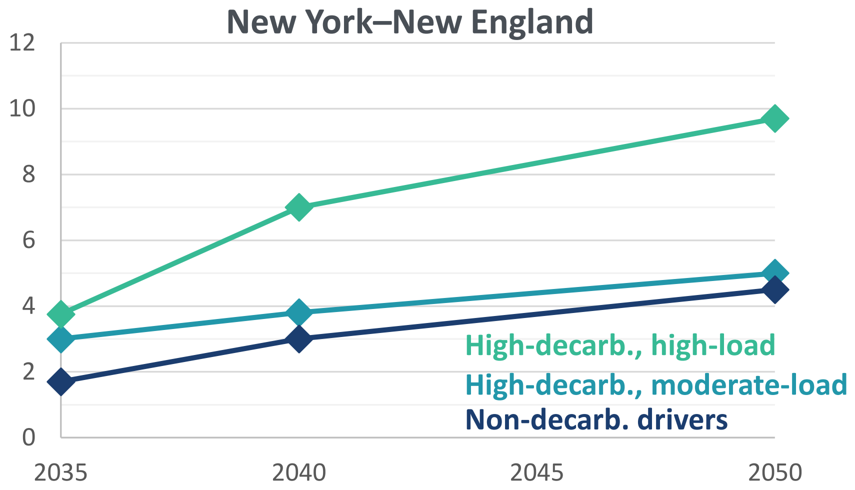
- **By 2050: 10 GW between Canada and Northeast is low-regrets**

Realizing the value of interregional transmission identified in these studies requires overcoming key barriers, particularly introducing intertie optimization and fully accounting for the value of existing and new interties

- *The exact magnitude of interregional transfer capability needs remain uncertain and depends on progress on decarbonization as well as load growth*

Estimated Range of *Low-Regrets* Transmission Expansion Needs (GW)





New York – New England: Interregional upgrades across the interface presents low-regrets, near-term opportunities

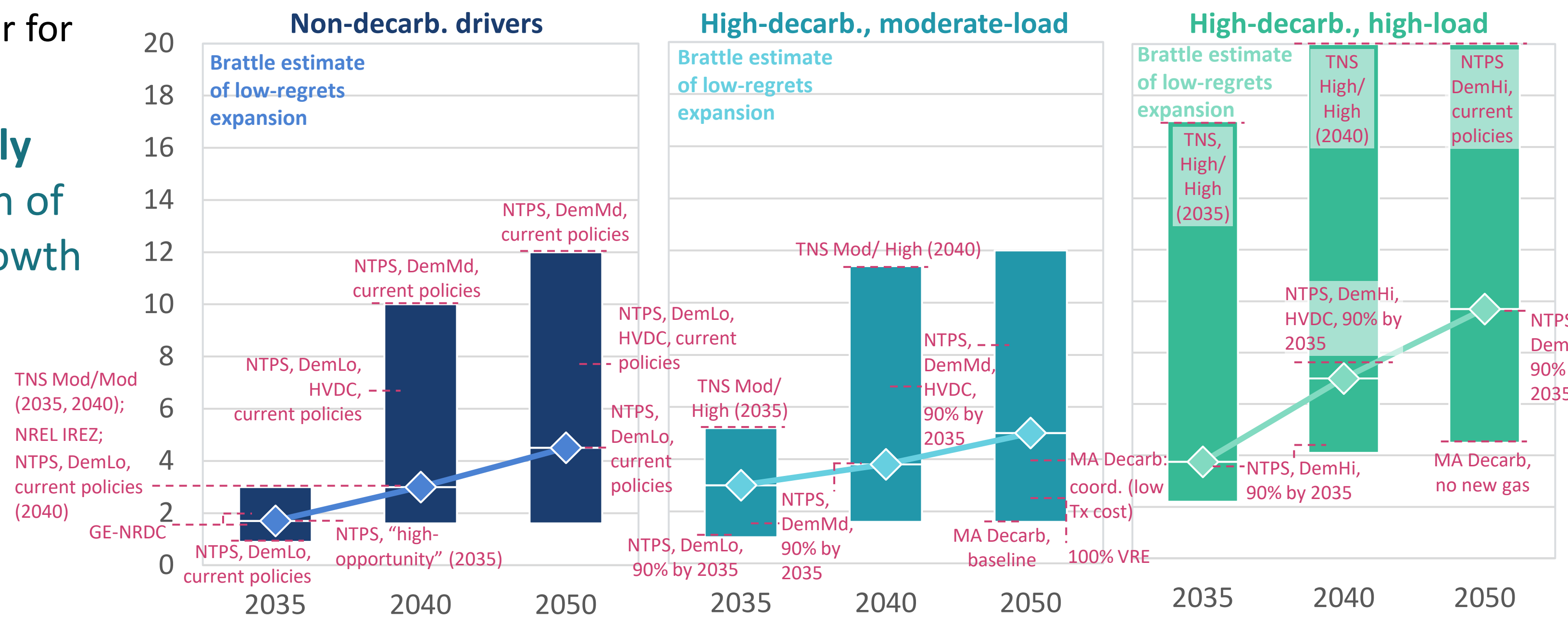
Based on multiple independent studies, we estimate that at least **1.7 GW** additional transfer capability between **NY and New England by 2035 is low-regrets**, even without considering the value of transmission for decarbonization.

- Similarly represents low end of range across studies and central estimate of studies that did not consider decarbonization as the driver for transmission development

Long-term (2040–2050) needs are highly uncertain; depend on scale and location of renewables adoption as well as load growth

- **3 GW by 2040 is low-regrets**, but may be conservative given decarbonization ambitions of both regions
  - Our low-regrets estimates for high-decarbonization scenarios conservatively skew towards the bottom of each range given the uncertainty amongst projects
- Option value for increased transfer capability is particularly valuable, given potentially high interregional needs

Estimated Range of New England–NY Transmission Needs (GW)



Notes: "Non-decarb. drivers" refers to scenarios where decarbonization was not a driver/constraint for the analysis. Ranges above cover transfer capability needs reported in the DOE 2023 Transmission Needs study (TNS, summarizing multiple studies), DOE National Transmission Planning Study (NTPS), GE-NRDC study, MA Decarbonization Pathways study, and NREL IREZ study. These ranges exclude scenarios deemed unrealistic, such as low-electrification and low-offshore wind scenarios in the MA Decarb. study which report low transmission needs due to new nuclear capacity in NY and CT. Annotations indicate noteworthy scenarios from these studies. NTPS results are from "AC" expansion scenarios unless denoted otherwise.

<u>Canada</u>: Significant expansion between the Northeast and Quebec is valuable long-term, and near-term for reliability in New York

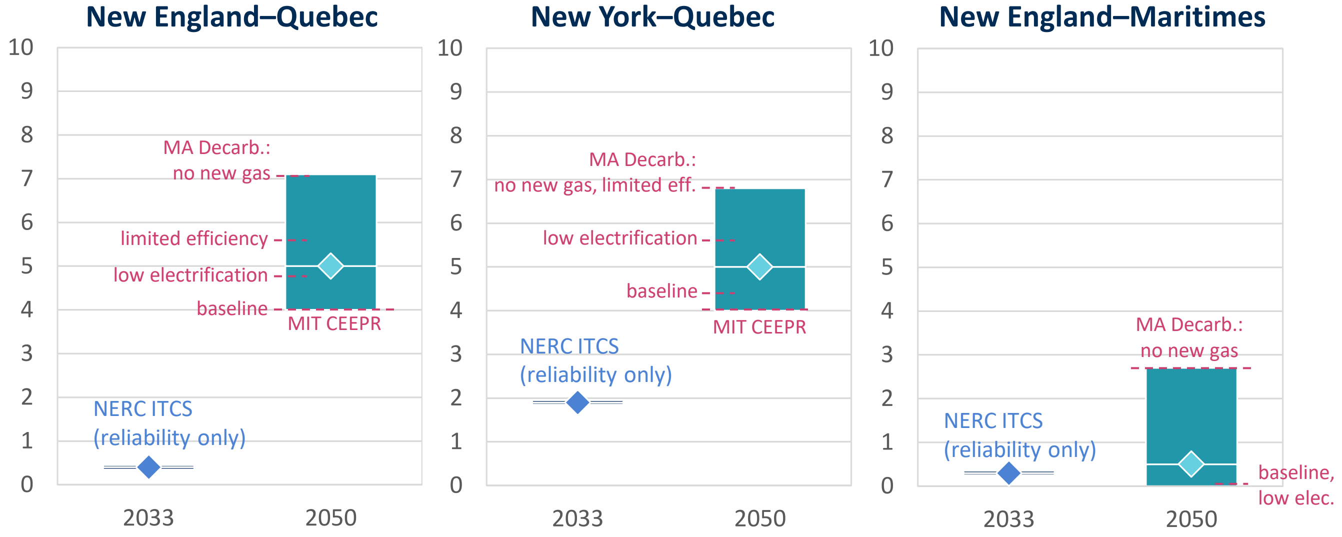
Based on multiple independent studies, we estimate that at least **5 GW** additional transfer capability **by 2050** between both **New England and Quebec** and **New York and Quebec is low-regrets**. When just considering reliability benefits, **1.9 GW between New York and Quebec by 2033 is low-regrets**

- While fewer studies considered transmission expansion to Canada, long-term (2050) studies show consistent value in significant expansion between Quebec and both New England and New York
  - Needs are greater (up to 7 GW) in higher renewables/low thermal generation futures
  - Value is derived from operating lines **bidirectionally** to balance Northeast renewables
- The MA Decarbonization Pathways study found a moderate need between **New England–New Brunswick** between 0–0.8 GW by 2050, scaling to 2.7 GW in a future with no new gas generation

NERC study demonstrates near-term reliability need

- **0.4 GW between NE–QC, 1.9 GW between NY–QC, 0.3 GW between NE–Maritimes**
- These figures consider resource adequacy only, and are therefore **conservative estimates that do not consider economic or public policy benefits of further expansion**

Estimated Range of Northeast–Canada Transmission Needs (GW)



Notes: Ranges above cover transfer capability needs reported in the NERC ITCS (2033 only), the MIT CEEPR study (2050 only) and the MA Decarbonization Pathways study (2050 only). Annotations indicate noteworthy scenarios from these studies.

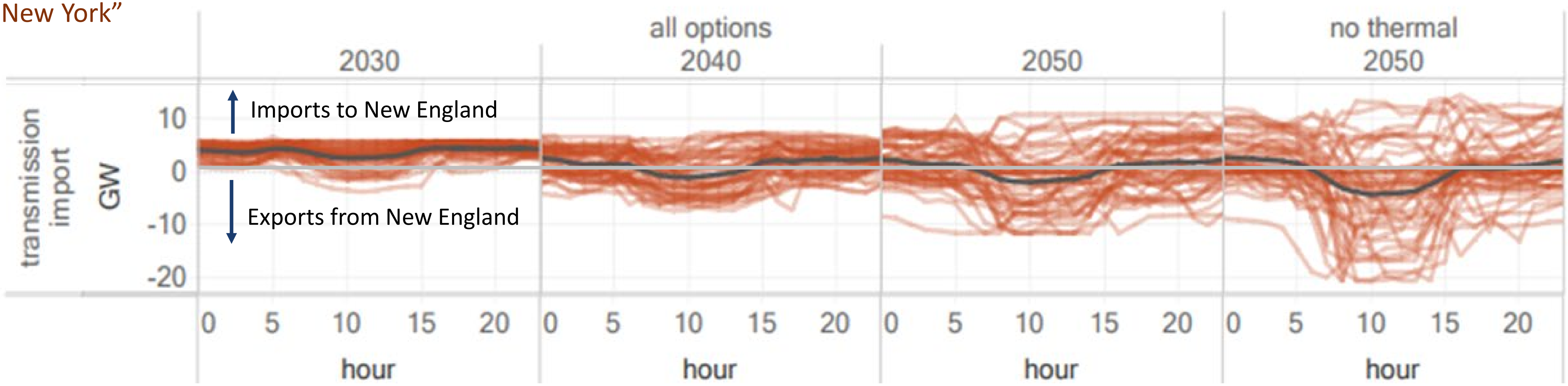
Additional transmission between the US and Canada will be beneficial … and increasingly be used bi-directionally

Example: MA Decarbonization Pathway Study shows additional transmission to Quebec is needed and bidirectional used starting in 2030:

"the Quebec hydro system in effect acts as a form of seasonal energy storage, with energy exported to Quebec during many hours to serve Quebec loads, and with imports from Quebec in other hours to serve loads in New England and New York"

Cost effective new transmission by 2050:

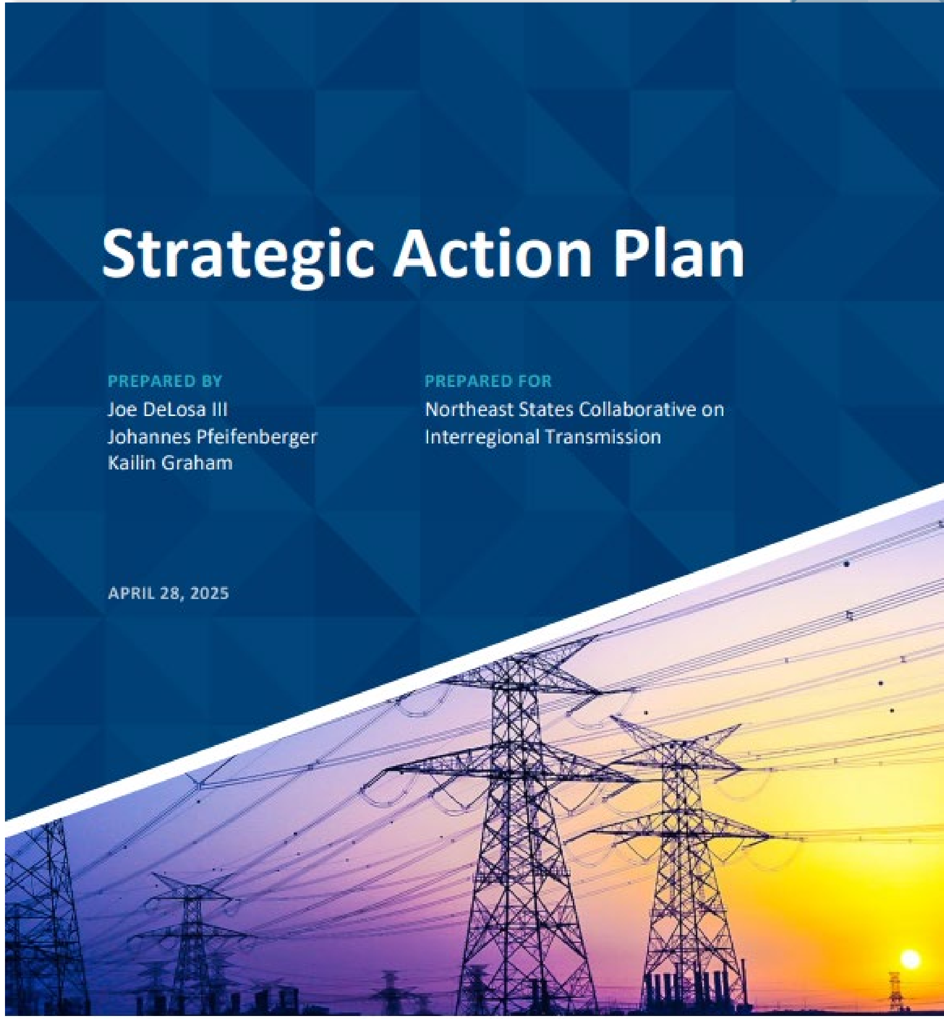
Zone from	Zone to	no thermal	regional coordination	limited efficiency	100% renewable primary	all options	der breakthrough	pipeline gas	offshore wind constrained
Quebec	Maine	2	1.2	1.1	0.9	0.6	0.6	0.6	0.9
Quebec	Massachusetts	4.3	4.8	3.7	3.3	2.7	2.8	3.1	3.9
Quebec	New Brunswick	0	0	0	0	0	0	0	0
Quebec	New York	6.8	6.8	6.8	4.7	4.4	4.2	5.6	3.8
Quebec	Vermont	0.8	0.7	0.8	0.8	0.8	0.8	0.8	0.8



Source: MA Decarbonization Pathways Study, Dec 2020, Table 8, Figure 27.

B. Northeast States Collaborative on Interregional Transmission

1. Strategic Action Plan: Overview
2. Near-Term Action Plan
3. Mid-Term Action Plan


Strategic Action Plan

PREPARED BY
Joe DeLosa III
Johannes Pfeifenberger
Kailin Graham

PREPARED FOR
Northeast States Collaborative on Interregional Transmission

APRIL 28, 2025

Strategic Action Plan: link

Brattle

Strategic Action Plan: Overview

The Action Plan is intended to advance the Collaborative's work by focusing efforts over the near-term (the next year) and mid-term (the next several years)

Near-Term Action Plan

A. Address Current Gaps in Interregional Transmission:
    - Candidate Project Identification (incl. RFI)
    - Allocation of Project Costs

B. Support Development of Uniform HVDC Design Standards with DOE Consortia

C. Assess Opportunities to Align and Optimize State Offshore Wind and Transmission Procurements

D. Develop Interregional Coordination Principles for Order 1920 Compliance Filings

E. Support Reducing Seams-Related Inefficiencies

Mid-Term Action Plan

A. Explore Need for Tariff Revisions Based on Lessons Learned

B. Explore the Creation of a Buying Pool for Transmission Equipment

C. Enable the Transition From Generator Export Lines to Network Transmission Facilities

A. Addressing Current Gaps in Interregional Transmission

The Action Plan sets out <u>near-term</u> steps necessary to identify, evaluate, select, and provide the opportunity for states to agree to share the cost of beneficial interregional transmission projects so they can be developed.

Interregional Candidate Project Identification

- In light of the lack of ISO-led processes for identifying beneficial interregional transmission, the Collaborative should **develop and issue a <u>Request for Information</u> (RFI)** on project designs that could meet low-regrets needs
- Scope of the RFI is focused on "low-hanging fruit" opportunities to identify the most cost-effective projects with near-term benefits and feasible implementation plans, including grid enhancing technologies
  - RTOs will need to be critical technical advisors and participants in the effort, given the ultimate need to integrate any identified transmission project with the RTO/ISO regional plans, and the roles of existing transmission coordination venues

Interregional Allocation of Project Costs

- For any interregional transmission project to be pursued following the RFI, states will need to agree on a framework for identifying benefits and **<u>sharing costs</u> of the resulting transmission investments**
- A successful cost allocation framework will need to be:
  - Sufficiently flexible to accommodate projects that address a variety of regional needs (e.g., reliability, economic, and policy)
  - Specific enough to be implementable by RTO/ISOs, without being overly restrictive or formulaic
- We recommend developing a strawman approach, including an invitation for comments on cost allocation structures and benefit methods, referencing existing best practices, Commission precedent, and other innovative approaches

Other Near-Term Action Plan Items

B. Support Development of Uniform HVDC Design Standards with DOE Consortia

Challenge:

- MSSC caps do not permit delivery of 2,000 MW from OSW based on latest 525kV bi-pole HVDC technology in NPCC

Action Items:

- DOE-funded POINTS Consortium
- Develop recommendations for technology standardization
- Engage industry to ensure recommendations are feasible for design and construction
- Enable states to agree on a common network-ready HVDC standard, to enable large HVDC facilities can be networked to provide expanded regional or interregional capabilities

C. Assess Opportunities to Align and Optimize State Offshore Wind and Transmission Procurements

Challenge:

- States are subject to different requirements that result in customized procurement frameworks

Action Items:

- Specify and provide the ability for states to coordinate and adopt a set of best practices, including by potentially:
  - Incorporating "network-ready" standard for export cables
  - Creating the option to convert export cables into open access facilities
  - Developing bid evaluation criteria to reflect transmission value
  - Combining state procurements into multi-state efforts
  - Preserving contracting flexibility to avoid supply-chain bottlenecks

D. Develop Interregional Coordination Principles for Order 1920 Compliance Filings

Challenge:

- Limited focus paid by RTO/ISO to the updated requirements of Order 1920 regarding interregional coordination

Action Items:

- Develop a set of interregional planning principles
  - Current timing restrictions should be eliminated
  - Should specify that <u>all</u> benefits to <u>each</u> region should be considered
- Coordinate with regions to incorporate Collaborative principles within Order 1920 coordination provisions

E. Support Reducing Seams-Related Inefficiencies

Challenge:

- Existing interregional transmission facilities are poorly utilized
- RTO/ISOs do not recognize value interregional transmission provides within planning analyses

Action Items:

- Resolve seam-related inefficiencies, including by advocating for intertie optimization
- Encourage regions to assess and consider the benefits of better-utilized interregional facilities within improved planning processes

Mid-Term Action Plan Items

A. Explore Need for Tariff Revisions Based on Lessons Learned

Challenge:

- Tariff provisions may not be well-suited to enable joint selection, pursuit, funding, and allocation of projects identified through the RFI.
- Projects identified by the Collaborative may be poorly suited for existing processes, as a project is unlikely to satisfy discrete regional needs in each region's planning process, which proceed on inconsistent timelines
- These existing processes overlook opportunities for mutually beneficial interregional transmission facilities

Action Items:

- Coordinate with RTO/ISOs to develop the necessary revisions (if any) to their market rules to enable the evaluation and selection of identified beneficial interregional projects, and apply the Collaborative's desired cost allocation

B. Explore the Creation of a Buying Pool for Transmission Equipment

Challenge:

- Lack of a centralized mechanism for coordinated bulk orders of HVDC equipment
- International competition for HVDC supply chain expansion and timely delivery

Action Items:

- Take initial steps towards determining the preferred structure and necessary scope of such a buying pool.
- Research the following questions:
  - What is the minimum buy-in for suppliers to participate?
  - What are off-ramps for changes in policy or schedule?
  - How much capital would need to be put "at-risk"?
  - Which technological criteria must be determined in advance?
  - How to account for technological evolution?

C. Enable the Transition from Generator Export Lines to Network Transmission Facilities

Challenge:

- Individual offshore wind generators' radial export lines may eventually become transmission facilities of a future networked offshore grid
- Current offshore wind procurements do not consistently specify and enable the future transition of export cables to open-access network transmission facilities

Action Items:

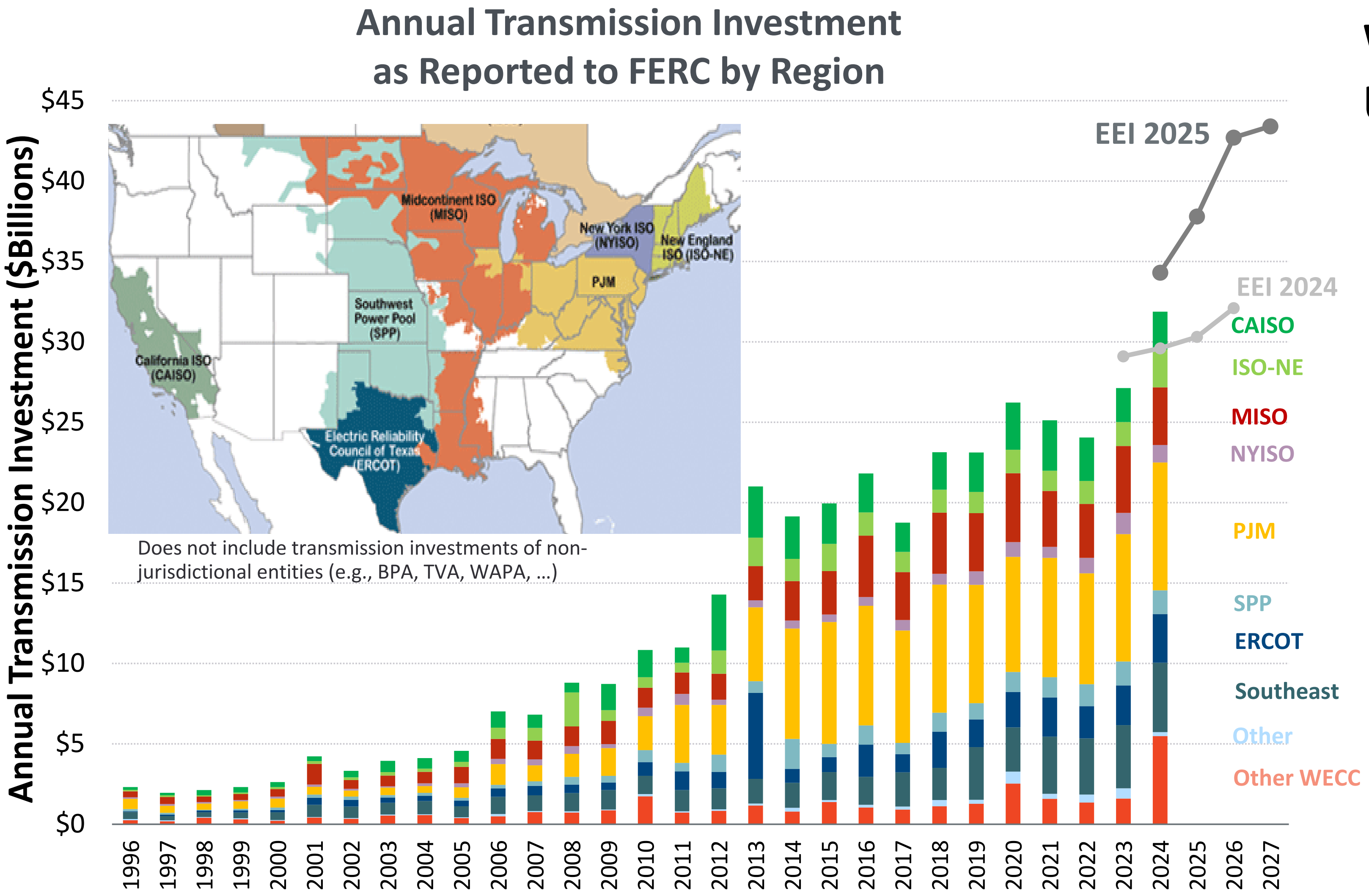
- Identify the necessary contractual and regulatory frameworks that could be adapted to create networked offshore grid
- Evaluate mechanisms that have been developed to meet this goal, including CAISO's Subscriber Participating Transmission Owner model.
- Lead a series of discussion with FERC staff to consult on the application of open-access precedent throughout the process

C. Order 1920 Opportunities to Improve Transmission Planning

1. Better deal with long-term uncertainties through proactive scenario-based planning
2. Use best-practice experience for benefit quantification
3. Consolidate silo-ed planning processes
4. Employ least-regrets planning criteria to minimize the risk of both over-building and under-sizing
5. Develop more flexible transmission solutions
6. Focus on more affordable outcomes, embrace ATTs/GETs, and include cost-control incentives
7. Explicitly consider interregional solutions to regional needs

Based on: Order 1920 Compliance: An Opportunity to Improve Transmission Planning beyond Mandates, ESIG, Oct 2024

Background: 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

We crossed $30 billion in annual U.S. transmission investments!

- Equipment cost increases likely account for the majority of the recent increases, with reemerging load growth behind the higher level of projected 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)

Best practices for proactive, comprehensive, long-term planning

The benefits (overall cost savings) of proactive planning increase for transmission planning processes that:

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 planning to address long-term 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

What is scenario-based, long-term planning?

Scenario-based planning is a process first developed in the 1940s and 1950s as a tool for integrating uncertainties into long-term strategic planning:

- Used by Shell with great success since the 1970s for long-term planning under large uncertainties
- **Allows planners to think, in advance, about the many ways the future may unfold and how to respond effectively and flexibly as uncertain future outcomes become reality**
- Ranks among the top-ten management tools in the world today
- Scenario = one fully-defined, plausible view of what the future may look like

Scenario-based planning is a multi-step process:

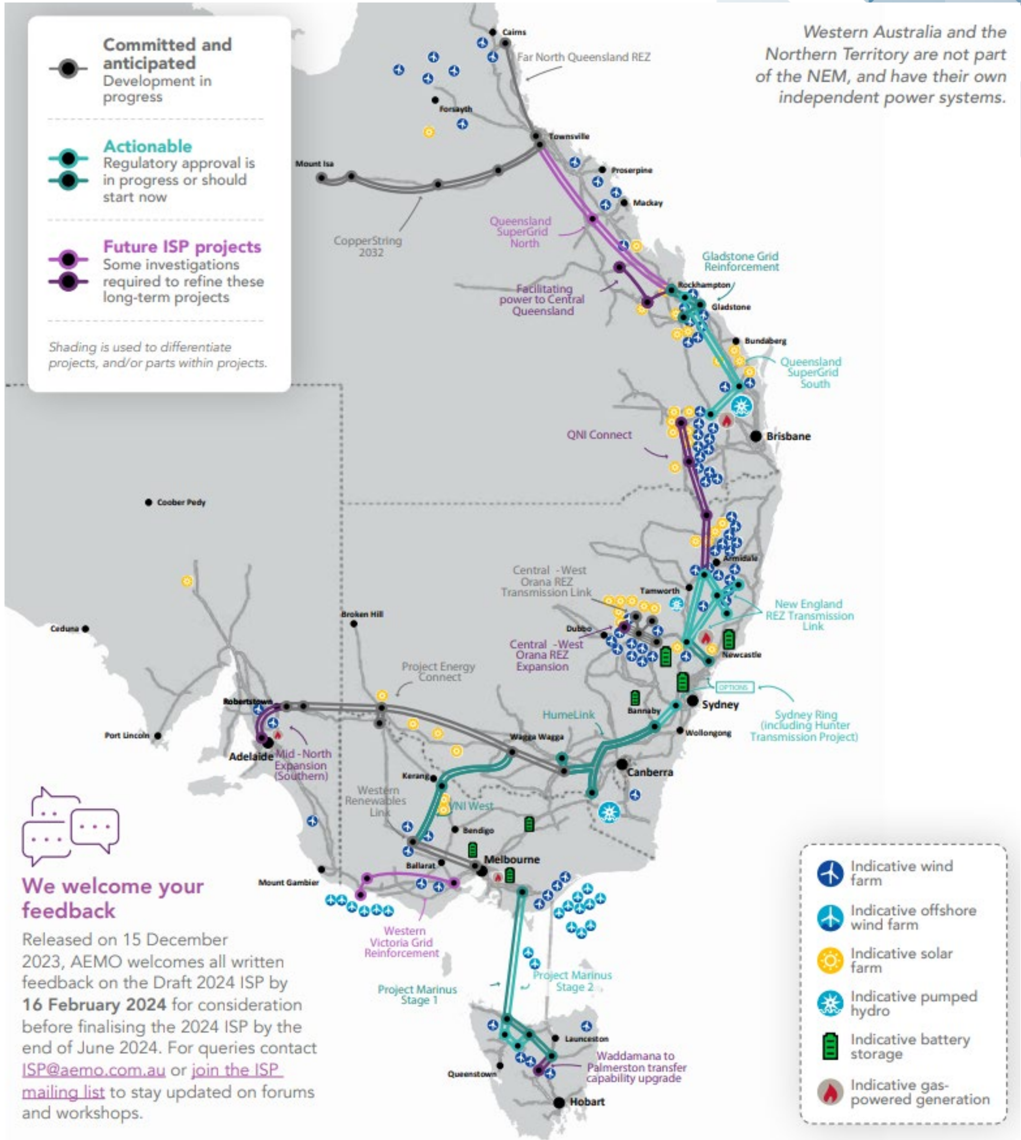
1. Define scenarios of plausible futures by scanning the current reality, trends and forecasts, uncertainties, and important internal and external drivers
2. Develop a series of plans (initiatives, projects, policies, tactics) that work well across multiple scenarios (e.g., by developing **solutions that are flexible and robust across all plausible futures**)
3. Implement preferred plan and define indicators to alert planners that a certain future is likely to occur, so they can take action (e.g., exercise options to address the new developments)

See Living in the Futures (hbr.org) and Scenario Planning-A Review of the Literature.PDF (mit.edu)

Example: Australian Integrated System Plan (ISP)

The Australian Energy Market Operator (AEMO) integrated planning process is "best in class" for proactive, scenario-based 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

Well-documented: proven practices for quantifying a broad set of transmission benefits

Take advantage of proven practices (as referenced in Order 1920)

- See our report with Grid Strategies for a summary of quantification practices, including benefits beyond the mandated ones

Most recent developments:

- Use weather-reflective (rather than weather-normalized) production cost and long-term expansion planning simulations (e.g., for 20-30 weather years)
- Production cost simulations with both day-ahead and real-time cycles to capture unpredictable real-time challenges and associated transmission value

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic “Day 1” market representation
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
4. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operational benefits

Over a decade of US experience already exists for identifying and quantifying a broad range of transmission-related benefits

SPP 2016 RCAR, 2013 MTF

Quantified

1. **production cost savings***
   - value of reduced emissions
   - reduced ancillary service costs
2. avoided transmission project costs
3. reduced transmission losses*
   - capacity benefit
   - energy cost benefit
4. lower transmission outage costs
5. value of reliability projects
6. value of mtg public policy goals
7. Increased wheeling revenues

Not quantified

8. reduced cost of extreme events
9. reduced reserve margin
10. reduced loss of load probability
11. increased competition/liquidity
12. improved congestion hedging
13. mitigation of uncertainty
14. reduced plant cycling costs
15. societal economic benefits

(SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016. SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July, 5 2012.)

MISO MVP Analysis

Quantified

1. **production cost savings** *
2. reduced operating reserves
3. reduced planning reserves
4. reduced transmission losses*
5. reduced renewable generation investment costs
6. reduced future transmission investment costs

Not quantified

7. enhanced generation policy flexibility
8. increased system robustness
9. decreased natural gas price risk
10. decreased CO_2 emissions output
11. decreased wind generation volatility
12. increased local investment and job creation

(Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011)

CAISO TEAM Analysis

(DPV2 example)

Quantified

1. **production cost savings*** and reduced energy prices from both a societal and customer perspective
2. mitigation of market power
3. insurance value for high-impact low-probability events
4. capacity benefits due to reduced generation investment costs
5. operational benefits (RMR)
6. reduced transmission losses*
7. emissions benefit

Not quantified

8. facilitation of the retirement of aging power plants
9. encouraging fuel diversity
10. improved reserve sharing
11. increased voltage support

(CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity)

NYISO PPTN Analysis

(AC Upgrades)

Quantified

1. **production cost savings*** (includes savings not captured by normalized simulations)
2. capacity resource cost savings
3. reduced refurbishment costs for aging transmission
4. reduced costs of achieving renewable and climate policy goals

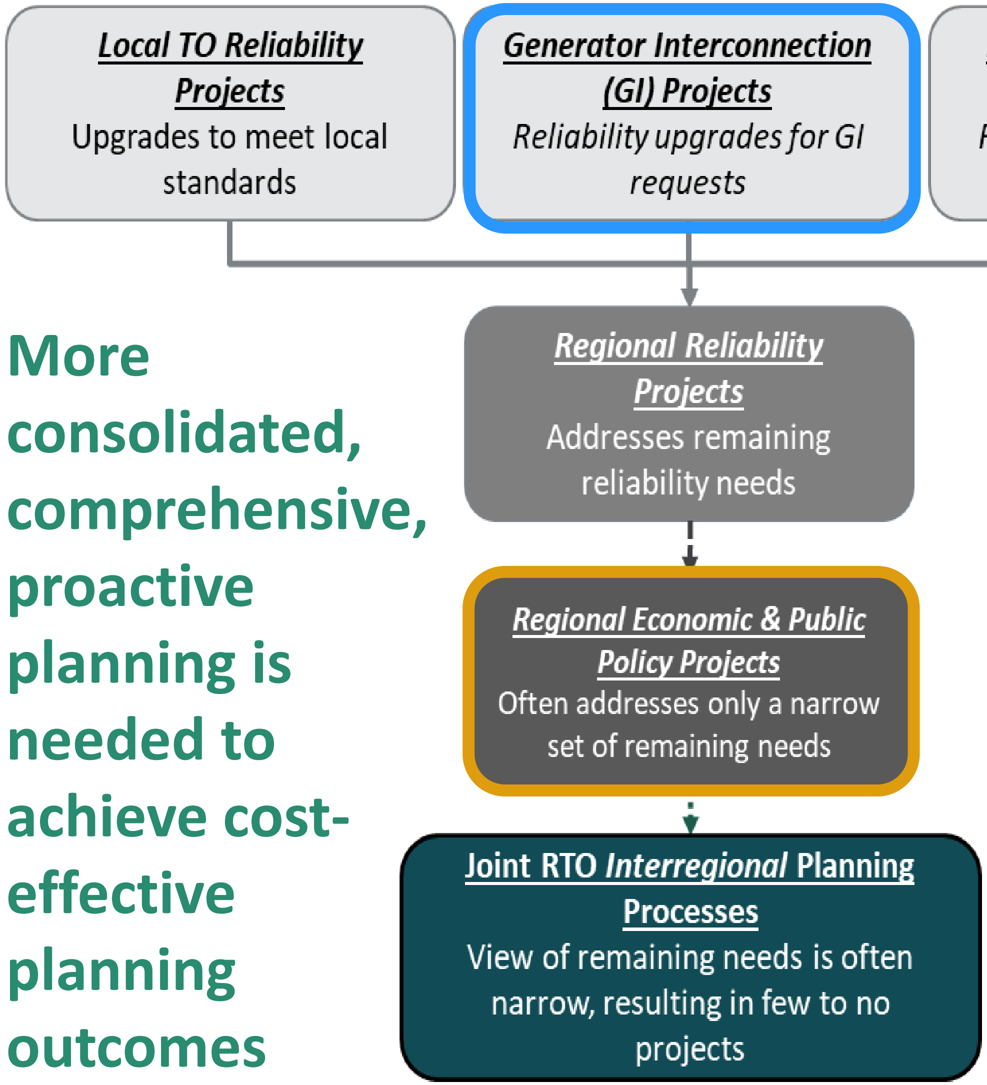
Not quantified

5. protection against extreme market conditions
6. increased competition and liquidity
7. storm hardening and resilience
8. expandability benefits

(Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015)

* Fairly consistent across RTOs

Order 1920 compliance is an opportunity to consolidate siloed and overly reliability-focused transmission planning



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

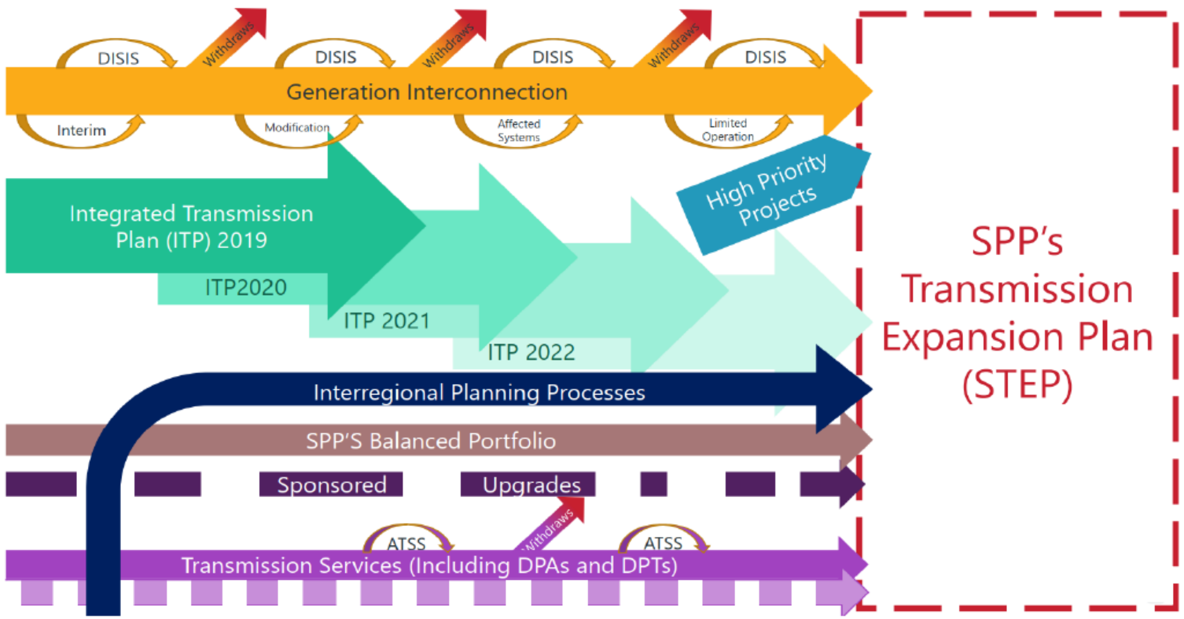
- Essentially no major interregional transmission projects have been planned and built in the last decade
- Numerous national studies show that more interregional transmission is needed to reduce total system costs

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

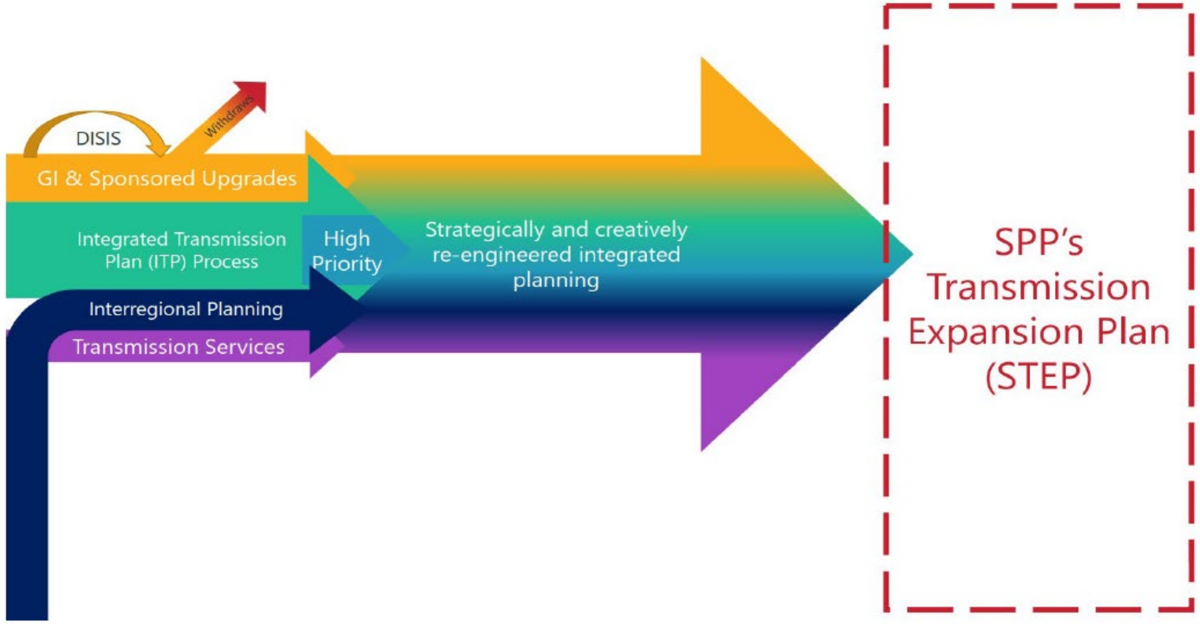
Example: SPP's proposed Consolidated Planning Process (CPP)

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

Risk mitigation through proactive "least-regrets" planning

Proactive planning needs to consider both (1) the high risk of delaying infrastructure investment and (2) the risk-mitigation offered by alternative transmission solutions:

- Given that it can take a decade to develop new transmission, **delaying investment can** easily **limit future options** and result in a **higher-cost, higher-risk** overall outcomes
  - "Wait and see" approaches can limit options, so can be more costly in the long term
  - We need to plan for both short- and long-term uncertainties more proactively – and develop least-regrets solutions that comprehensively and flexibly address uncertain future needs
- **"Least regrets" planning** to minimize the risk of both overbuilding and undersizing

  Use full set of scenarios in planning to identify solutions that minimize both sources of possible regrets:
  1. Avoid oversized projects that "regrettably" end up too costly and under-utilized; and also
  2. Avoid many "regrettable" high-cost outcomes caused by undersized transmission solutions
- Focusing on just one scenario cannot distinguish solutions with higher/lower costs and risk
- Taking probability-weighted averages across scenarios is insufficient as it (a) assumes risk neutrality and (b) does not quantify the value of flexibility and risk mitigation

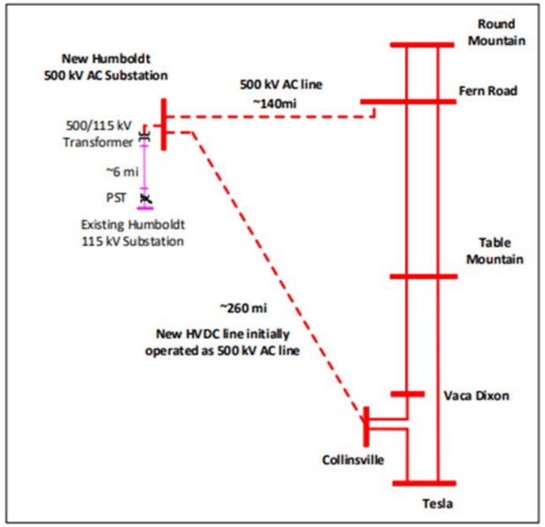
Reduce costs and mitigate risk through more flexible solutions

Planning processes need to develop flexible transmission solutions that create valuable options, given high long-term uncertainties:

- Example 1 – rebuild aging single-circuit 230kV line as 345kV-ready with double-circuit towers to create option to: (1) initially operate circuit at 230kV, (2) later add 1 GW of transfer capability by stepping it up to 345kV (with transformation), and (3) if needed, expand the capacity by adding a second circuit
- Example 2 – CAISO's expandable offshore-wind integration solution with HVDC-ready 500kV line:

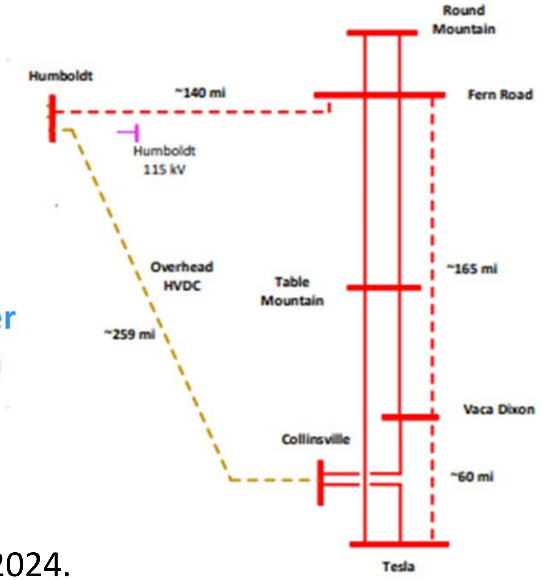
Two new 500kV lines, of which one is "HVDC-ready"

Phase 1: Base Case Plan
(1,607 MW)



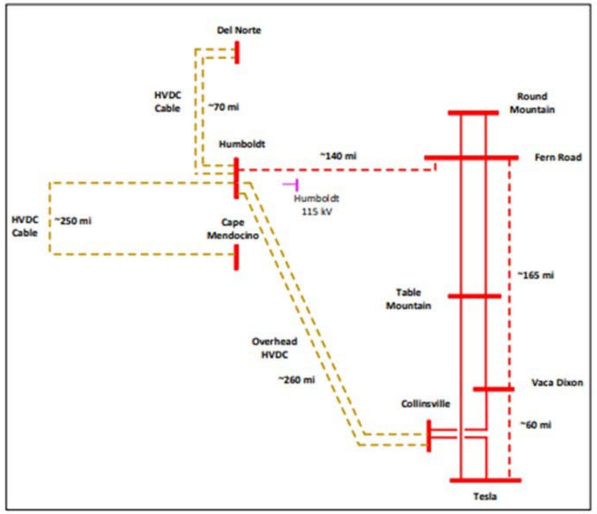
Add DC converter stations to each end of the line

Phase 2: DC Conversion
(3,100 – 3,300 MW?)



Add a second HVDC line

Phase 3: Expanded Plan (Option B)
(8,045 MW)



Source: CAISO-2023-2024-transmission-plan, May 23, 2024.

Options for achieving 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)

How can we double or triple US transmission capability … and 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

3. New transmission

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

2. Upgrades of existing lines

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

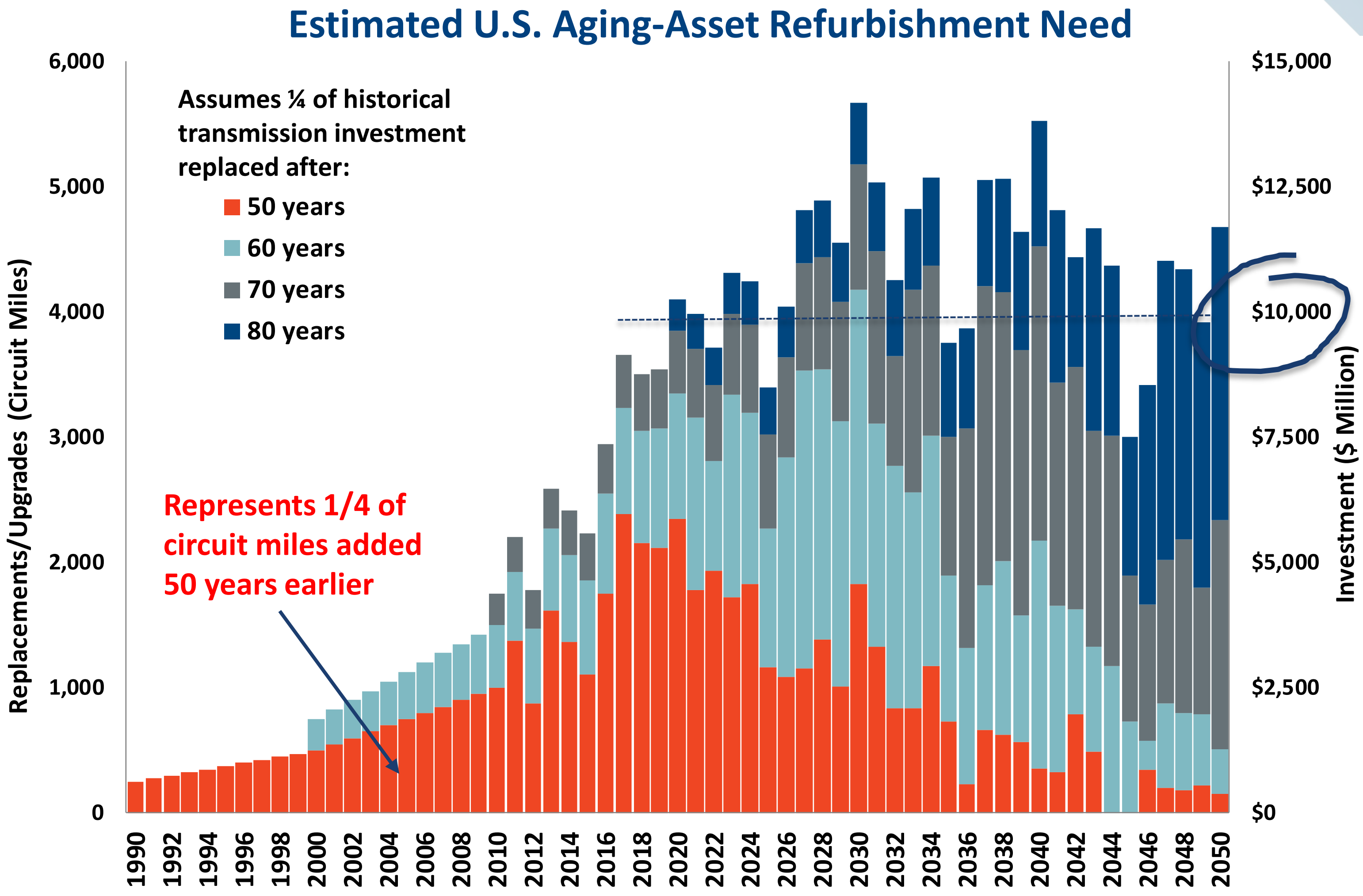
Examples:

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 $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

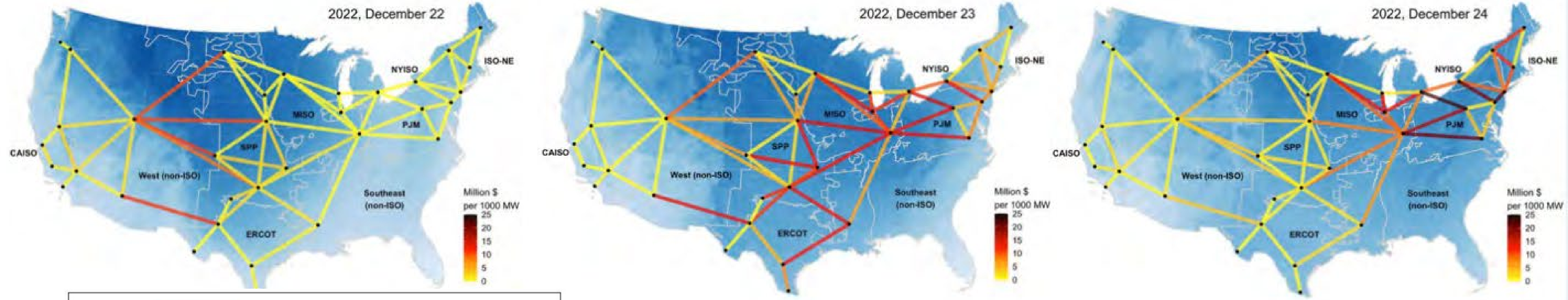
More efficiently plan and utilize interregional transmission

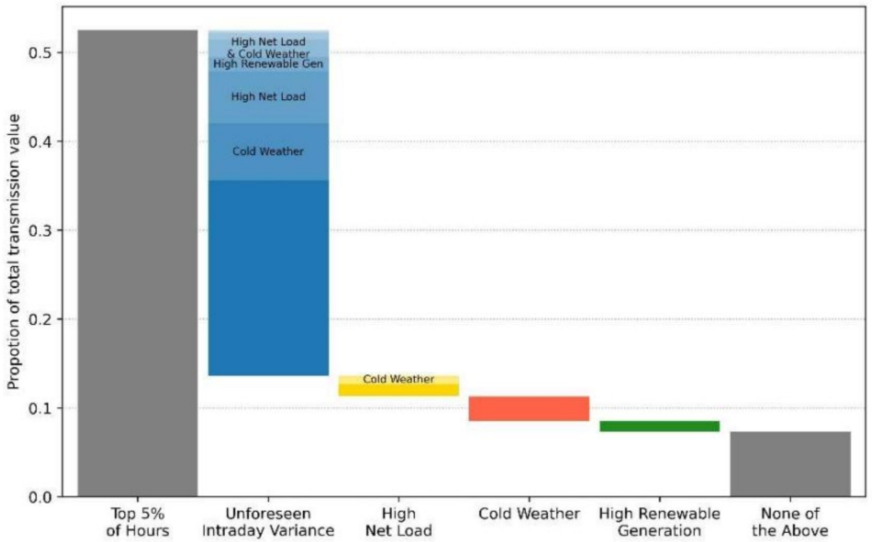
Significant seams-related inefficiencies exist between RTO markets, which need to be addressed to capture the full value of both existing and new interregional transmission:

1. **Interregional transmission planning** is mostly not existing or ineffective (beyond merchant T)
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. **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)
4. **Loop flow management** through market-to-market coordinated flowgates (with shares of firm flow entitlements) under the existing JOAs
5. **Inefficient trading** across contract-path market seams and the need for intertie optimization (see link)

Interregional transmission value is concentrated into few hours

Highest transmission value is realized in relatively few hours during challenging and extreme events. Example: **Winterstorm Elliot** (2022)





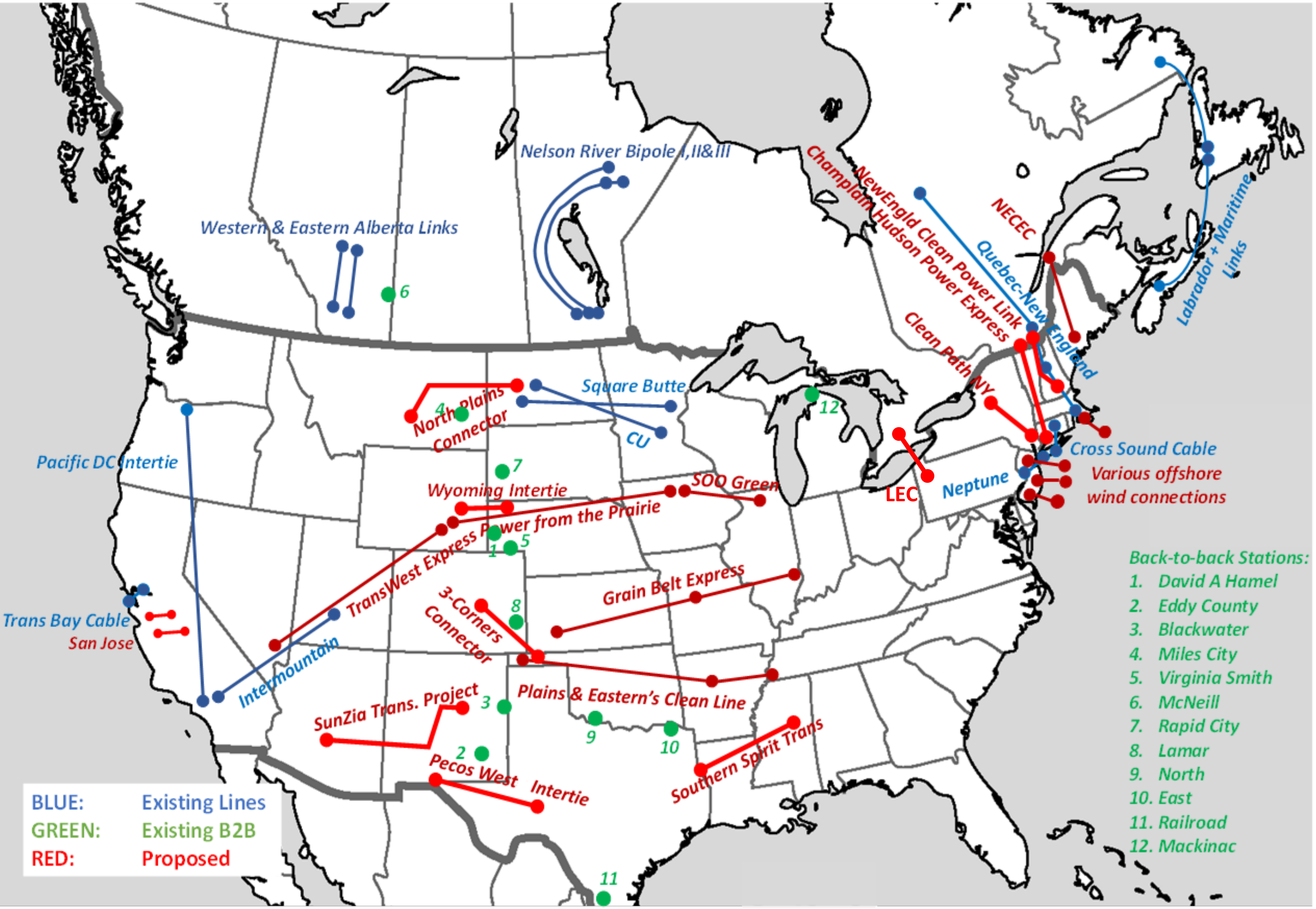
Findings:

- Real-time values (reflecting actual conditions) are higher than DA values
- On average, about **half of the value is concentrated in top 5% of all hours**
- Most of that value is due to unpredictable real-time market conditions that are not foreseeable on a day-ahead basis
- Estimated benefits exceed costs of expanding interregional paths

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

Today, in the US interregional transmission needs are addressed mostly through proposed merchant HVDC lines

North American HVDC Projects (Existing and Planned/Proposed)



Source: Jim McCalley, Iowa State University

Most U.S. interregional transmission projects are HVDC lines proposed by merchant and OSW developers (i.e, not planned by system operators)

Main HVDC advantages:

- High capacity (1-5 GW), long-distance
- Efficient right of way (including underground and submarine)
- Controllable power flows (for transmission access, economic dispatch and during contingencies)
- Synchronous and asynchronous applications
- Grid-forming capability / weak AC grids
- Grid services (to support AC network)

Order 1920 may facilitate planning of interregional transmission

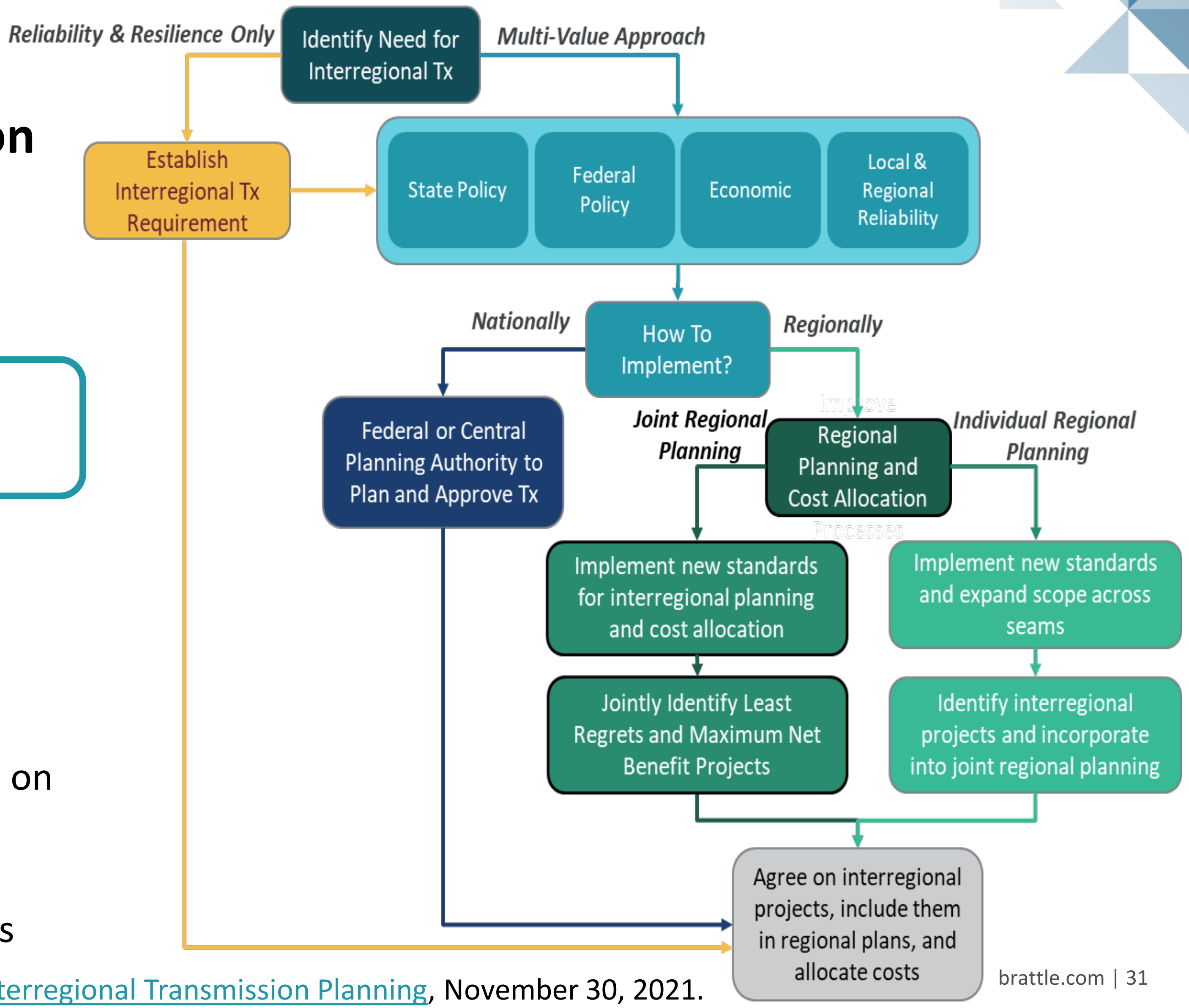
Four pathways are available for actionable interregional transmission planning:

1. **New Interregional Tx requirements?**
2. **New Federal planning?**
3. **Improve joint RTO planning**
4. **Expand planning by individual RTOs**

These could be improved trough Order 1920 compliance

Order 1920 only requires improved interregional coordination:

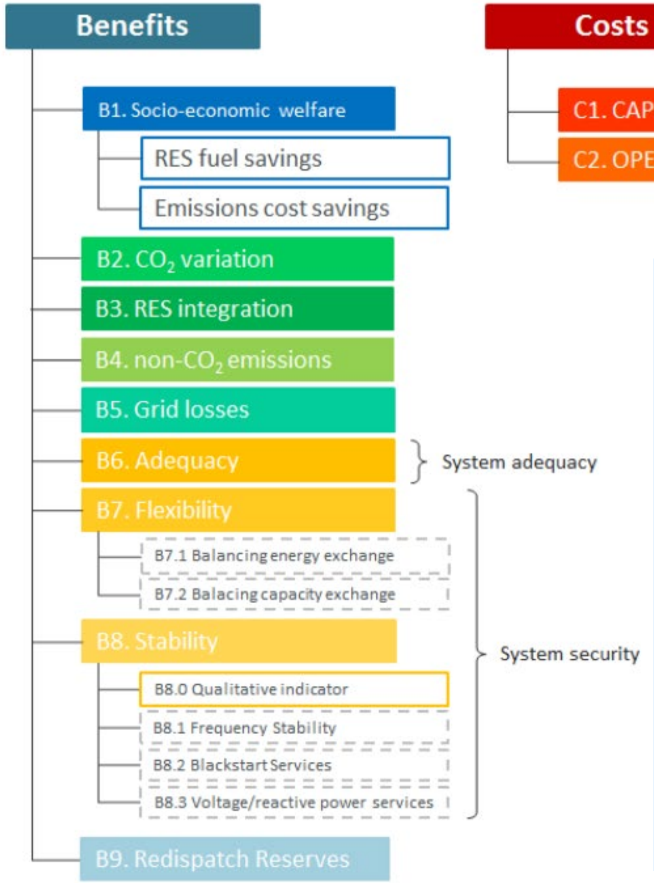
- Sharing new long-term planning information on needs and possible solutions
- Process for proposing interregional projects
- Regional evaluations of interregional projects



Source: A Roadmap to Improved Interregional Transmission Planning, November 30, 2021.

Example: Continent-wide proactive, multi-value planning. The European 10-year Network Development Plan (TYNDP)

ENTSO-E: Standardized Multi-value Benefit-Cost Analysis Framework for EU-wide Transmission Planning (incl. HVDC)

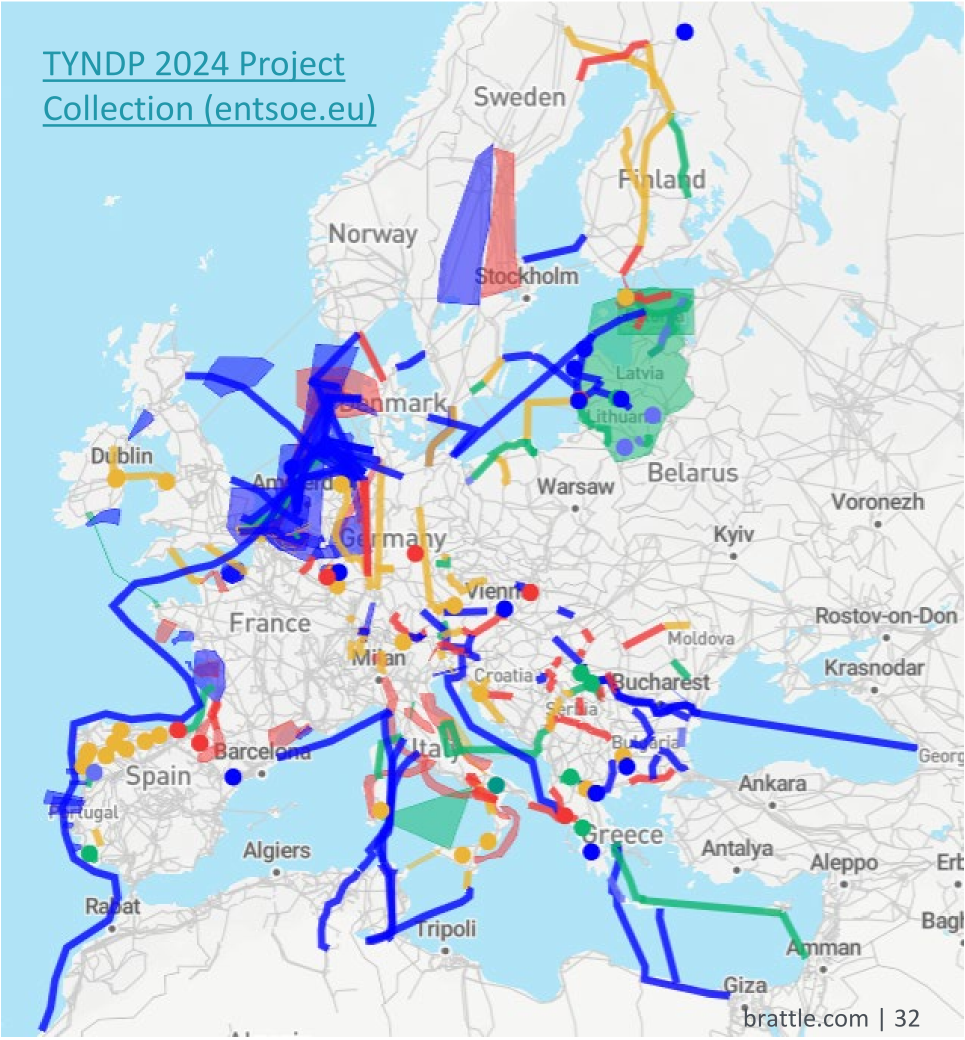


Entso-E Planning and CBA framework

- Association of European Grid Operators
- 10 year investment plan
- Scenario-based looking out 10-30 years
- Standardized benefit-cost analysis
- Specifically addresses HVDC benefits: Cost savings achievable from optimized dispatch of HVDC lines; transient, voltage, and frequency stability benefits of HVDC lines; blackstart services; voltage and reactive power support

Source: ENTSO-e, *4th ENTSO-e Guideline for Cost Benefit Analysis of Grid Development Projects*, Oct 18, 2023, Figure 8; TYNDP 2024 Implementation Guidelines, Mar 4, 2024.
For a summary of the ENSTO-e framework, incl. HVDC, see pp. 77-80 here.

10-Year Network Development Plan (TYNDP) to Evaluate 176 Transmission, 33 Storage Projects



D. Generator Interconnection

Improving generator interconnection studies and planning

U.S. generator interconnection processes received poor grades. Improving them requires addressing five elements of the interconnection processes:

1. **GI Process and Queue Management:** individual vs. cluster studies, type of studies and contractual agreements, readiness criteria, financial deposits, study and restudy sequences, etc.
2. **GI Scope and "Handoff" to Regional Transmission Planning:** are major ("deep") network upgrades triggered by incremental generation interconnection requests or handled proactively and comprehensively through regional transmission planning?
3. **GI Study Approach and Criteria:** study assumptions, modeling approaches, and specific criteria differ significantly across regions (e.g., firm/non-firm study differences, injection levels studied, are generation redispatch opportunities and "remedial action schemes" considered?)
4. **Selecting Solutions to Address the Identified Criteria Violations:** most regions select only traditional transmission upgrades to address criteria violations; grid-enhancing technologies (such as power-flow-control devices or dynamic line ratings) often are not seriously considered and accepted
5. **Cost Allocation:** most U.S. regions require the interconnecting generator (or group of generators) to pay for all upgrades identified, even though (a) there may be significant regional benefits to loads and other market participants and (b) more cost effective (multi-value) regional solutions may exist

Generator Interconnection: Scorecard assessing 2023 status quo

FIGURE 5 | LBNL Estimate of Interconnection Process for IAs Executed from 2018 to 2022[22]

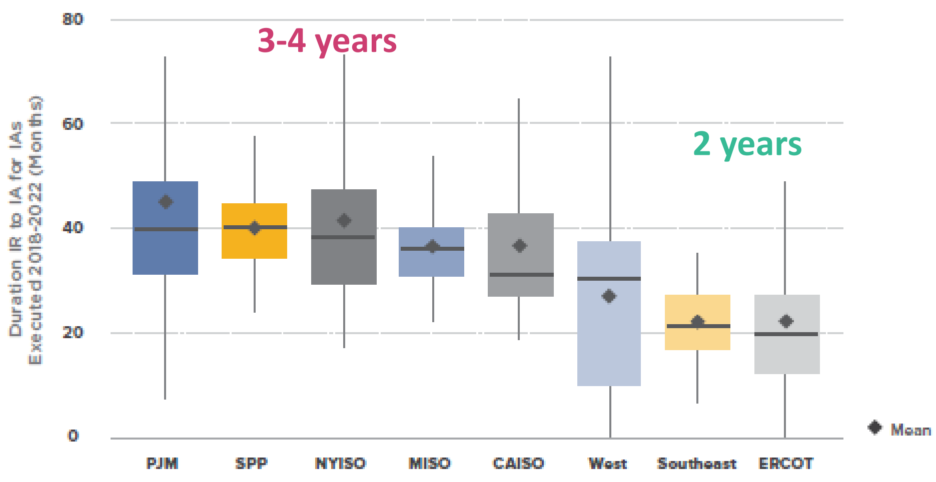


FIGURE ES–1 | Interconnection Agreements Executed Through 2022 for Interconnection Requests Submitted from 2012-2020[2]

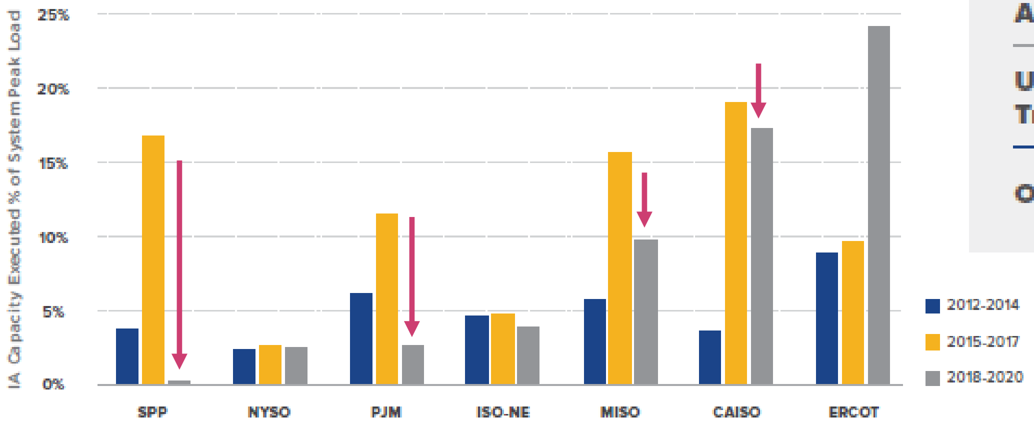


TABLE 1 | Generator Interconnection Scorecard Grades

	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP
Interconnection Process Results	B-	A	C	C	D	D	C-
Pre-queue Information	C+	C	D	C+	C	C	C-
Interconnection Study Process Design	B	A-	C-	D+	B-	F	D
Study Assumptions, Criteria, Replicability	A	A+	C+	D	C+	F	C
Usefulness of Interconnection Alternatives	B+	B	D	B-	D	D	B
Using Regional Transmission Planning	A-	D	D	B	C+	D+	C+
Overall grade	B	B	D+	C-	C-	D-	C-

Source: Grid Strategies-Brattle Generator Interconnection Scorecard, Feb 2024.

Generator interconnection: Recommended improvements

FERC sought to address the significant delays and backlogs associated with generator interconnection to the bulk transmission system in **Order 2023**:

- Adoption of cluster studies for interconnection requests in a given year
- Switch from "first-come, first-served" to "first-ready, first-served"
- Readiness requirements include higher study deposits, 90% site control at time of request, 100% at start of Facilities Study
- Publish heatmaps of available transmission capacity
- Deadlines for completion of interconnection studies
- Consideration of grid-enhancing technologies (GETs)

Order No. 2023 is a step in the right direction, but there is more to do to improve the interconnection process.

- We (with GridStrategies) recommended these additional reforms that would increase the certainty and cost-effectiveness of generator interconnection

GridStrategies-Brattle Report, Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid (August 2024)

- **REFORM 1 | *Adopt an interconnection entry fee for proactively planned capacity*,** provides interconnection customers significant interconnection cost certainty and addresses cost allocation of the upgrades identified through proactive planning processes. This reform allows projects to move forward with upfront certainty by specifying in advance the cost information in exchange for taking on some of the cost of planned transmission buildout.
- **REFORM 2 | *Implement a fast-track process to utilize existing and already-planned interconnection capacity*,** implements an efficient process to quickly utilize existing and planned system capacity. In combination with Reform 1, these reforms create a fast-track process that opens up available transmission headroom for full utilization and prioritizes its use by "most ready" generator projects.
- **REFORM 3 | *Optimize the interconnection study process*,** targets improvements to the interconnection study process to increase the system headroom considered to be "available" for interconnecting new resources through existing and new fast-track processes. It also identifies reforms necessary to make the study process more efficient. In combination with Reforms 1 and 2, interconnection requests should proceed through the study process more quickly.
- **REFORM 4 | *Speed up the transmission construction backlog*,** addresses growing constraints to constructing network upgrades needed to bring new resources online after completing the interconnection study process.

Options for interconnecting resources 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: Are Firm Capacity Requirements Outpacing Replacements?, January 25, 2024

1. Fast-track Sharing and Transfers of Existing POIs

Implement new fast-track process for sharing and transferring existing POIs to bypass long interconnection queue for new POIs

- Fast-track sharing of existing POIs (both surplus interconnection capacity & sharing of energy)
- Fast-track the transfers of existing POIs (e.g., POIs of retiring plants; POIs build through SAA)

Why?

- RTOs have 100+ GW of existing POIs at retiring plants! … most of which are in attractive locations for new storage, renewables (e.g., as noted in the Illinois draft REAP report), and natural gas plants (Example: PJM client rejected new solar+storage bid at retiring fossil plant because ISA would take 5-6 years)
- More quickly assign POIs built under proactive planning processes (e.g., NJ SAA in PJM)
- Sharing POIs is attractive: aging resources rarely dispatched when renewable generation is high; solar+storage

Examples:

- Separate MISO and SPP processes for transferring existing POIs (unlike in PJM, presumes no material impact)
- MISO "energy displacement agreements" (between existing and new resources to ensure that the total amount of shared interconnection service at the POI remains the same)
- See 2024 GridLab Surplus-Interconnection Report
- SPP's 2025 "Surplus Plus" proposal to further accelerate generator additions at existing POIs

2+3+4+5. Existing Headroom / First-ready / GETs & RAS / ERIS

- Identify "headroom" (hosting capacity, Order 2023 "heat map" requirement)
  - Example: CAISO identified interconnection requests for which 31 GW of energy-only headroom (23 GW of which are firmly deliverable) already exists without <u>any</u> additional network upgrades
- Fast-track generation resources that can be developed quickly (e.g., "first-ready" projects with minimal POI upgrades … beyond Order 2023 "first-ready, first-served" requirement)
  - Like PJM's "fast-lane" transition process for projects with minimal upgrades, but could be made permanent
  - CAISO's 2023 Interconnection Process Enhancements
- Allow interconnection needs to be addressed by grid-enhancing technologies (GETs) and "simple" remedial action schemes (RAS or system protection schemes, SPS)
  - GETs, such as power flow control devices, only need to be "considered" (but not used) per FERC Order 2023
  - RAS example: CAISO identified 21 GW of energy-only (16 GW of deliverable capacity) interconnection headroom that can be created quickly and inexpensively with RAS
- Simplify ERIS (energy-only) interconnection criteria for new POIs with option to upgrade to NRIS (capacity) later
  - Consider in interconnection studies the ability to manage (e.g., dispatch down) energy resources in nodal market
  - Examples: SPP ERIS, Enel working paper (speeds up energy-only interconnections to slim down the interconnection queue for firm (capacity) interconnections

6. Proactive, Holistic Long-term Transmission Planning

Proactively and holistically planning for long-term transmission needs can reduce total customer electricity costs and speed up interconnection of new resources

- Experience shows that simultaneously addressing all transmission needs (for generation interconnection, reliability, economic, public policy, and interregional needs) reduces costs:
  - CAISO TPP and European ENTSO-E planning and CBA framework, which includes interregional needs
  - MISO LRTP and Australian ISP (which do not consider interregional needs)
  - 2021 PJM study: $3.2b in transmission for 75 GW of clean energy resources -- shows that holistic planning for even just the next decade of generation interconnection needs would offer substantial cost reductions
- Concept: consider all near-term and long-term transmission needs (including public-policy needs through 2040-50) in approving the next decade of transmission upgrades
- Important: immediately reflect approved transmission upgrades in the "base case" for generation interconnection studies (e.g., as MISO did with approved MVPs)
- Include interregional solutions:
  - Jointly plan for interconnection needs near seam (e.g., SPP-MISO JTIQ offering documented cost reductions)
  - Additionally: replace ineffective Coordinated Transaction Scheduling (CTS) with intertie optimization to improve utilization of interregional transmission and dispatch efficiency near seams, as recommended by IMM

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 also 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), a IEEE Senior Member, and currently serves as an advisor to research initiatives by the U.S. Department of Energy, the National Labs, and the Energy Systems Integration Group (ESIG).

Hannes 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.

Brattle Group Publications on Transmission

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.
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, DeLosa III, Transmission Planning for a Changing Generation Mix, OPSI 2022 Annual Meeting, October 18, 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.
Pfeifenberger, Newell, Graf and Spokas, "Offshore Wind Transmission: An Analysis of Options for New York", prepared for Anbaric, August 2020.
Pfeifenberger, Newell, and Graf, "Offshore Transmission in New England: The Benefits of a Better-Planned Grid," prepared for Anbaric, May 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