Transmission: A Means to Achieving Affordable Electricity in New England

PREPARED BY

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necpuc

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Brattle

The Challenge: How to Achieve an Affordable Energy Transition

The challenge to achieving an affordable clean-energy transition is formidable:

1. Much of the (aging) existing generating resources will need to be replaced over the next two decades
2. Electrification and data center load growth will double the amount of generation supply needed (even with EE)
3. Local, regional, and interregional transmission capacity will need to double or triple to achieve a cost-effective outcome (as numerous studies have already shown)

More investment will be needed than can easily be provided and recovered

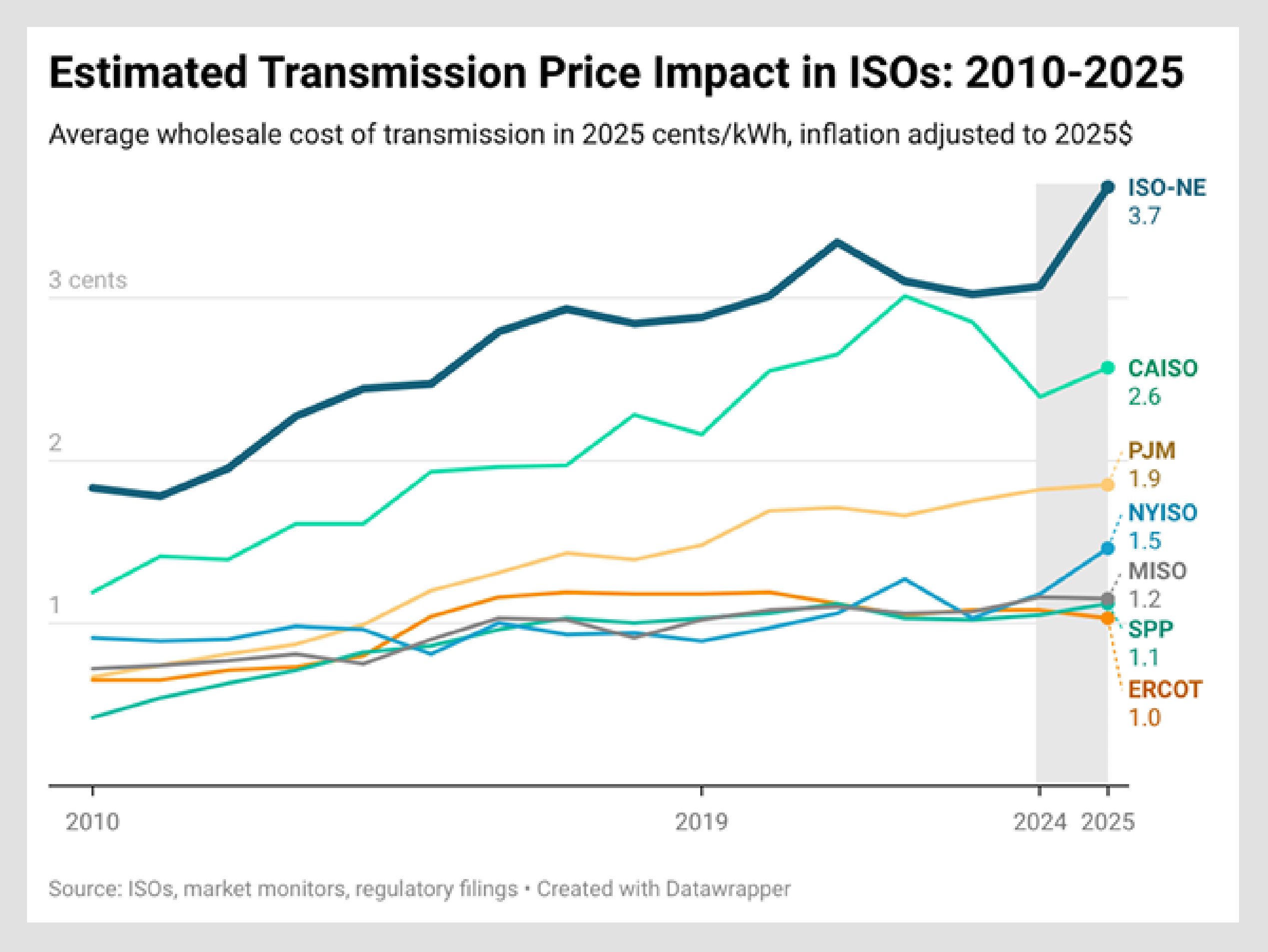
Unless done efficiently and cost-effectively, the size of investments and customer rate impacts will quickly exceed feasible and acceptable levels!

Nobody will be "happy" if rates start to exceed certain levels

- Unaffordable rates will undermine or delay policy goals
- High fixed costs will create uneconomic bypass of existing facilities, which will further increase total costs
- Unhappy customers and regulators create risk and challenges for regulated companies and their investors
- Utility credit ratings will deteriorate and limit the amount of investments that can be financed

FERC-approved transmission infrastructure costs in New England increased in 2025, pushing retail prices higher *(as did a change in ancillary services)*

- Many New England states saw retail price increases in 2025: ME (2.5 ¢/kWh), RI (0.9), MA (0.9), CT (0.5)
- One key reason is that transmission infrastructure costs substantially increased, up **0.6 ¢/kWh on average**
- Costs in ISO-NE increased in recent years due to reliability needs, aging infrastructure, and inflation; the increase in 2025 was also due to under-collection of previous costs
- Costs also increased in some other regions, but less so than ISO-NE
- *Note: ISO-NE made changes to its day-ahead **ancillary services** market in March 2025, via "Forecast Energy Requirement" credits. According to the market monitor, this resulted in additional costs of ~0.5 ¢/kWh in 2025.*



Note: ISO-NE data shown in figure are dominated by trends in regional network service (transmission OpEx and CapEx paid for by all customers in ISO-NE, given the shared nature of the assets) but also include estimates of local network service (smaller lines, the OpEx and CapEx of which vary by utility).

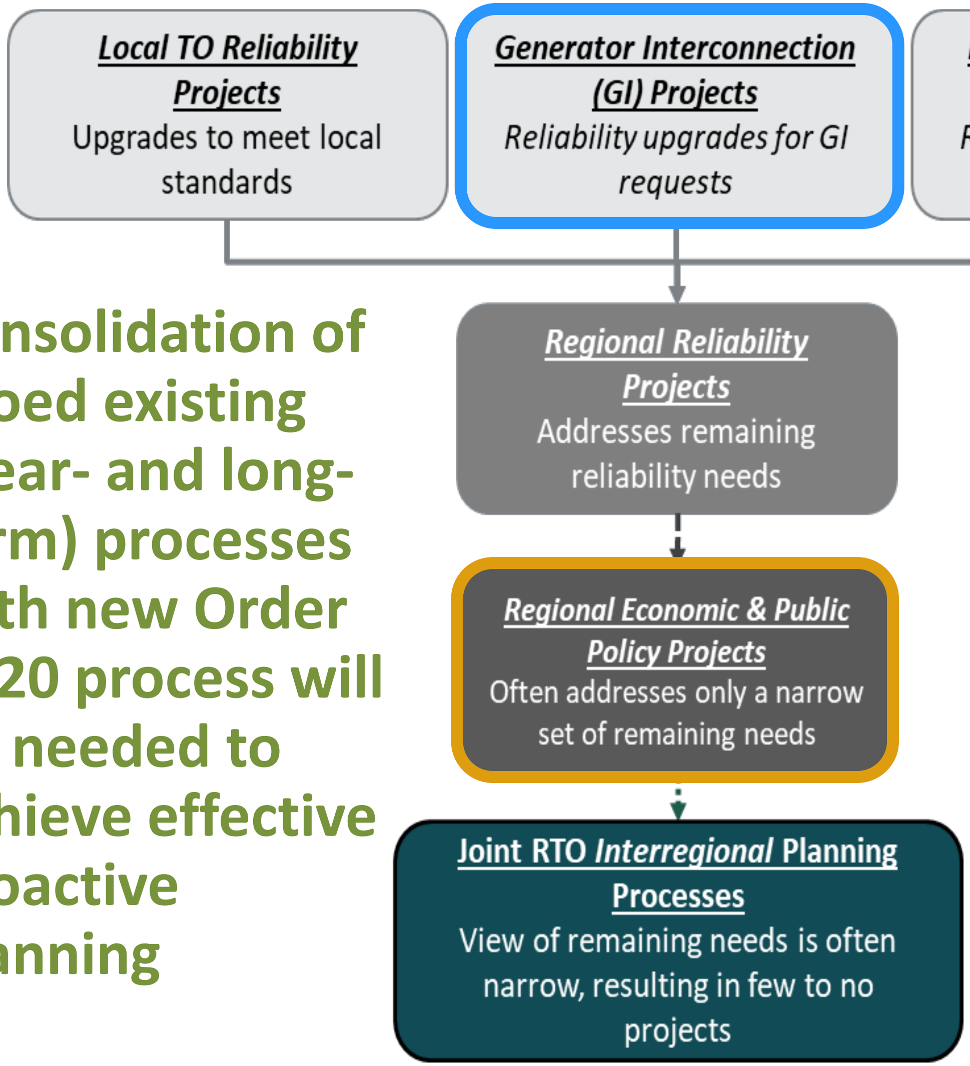
Source: LBNL-Brattle, Electricity Price Trends, 2026 Update

Transmission: options for achieving more affordable outcomes

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

1. More **proactive and holistic transmission planning**
   - Multi-driver/value planning (incl. for generator interconnection) to find lower-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**
   - Broad-based PBR, targeted incentives, soft/hard caps, shared savings/overruns
4. **Competitive solicitations**
   - With focus on more holistic solutions and added cost-control incentives
5. **Efficiency and demand flexibility**
   - To reduce transmission, distribution, generation, and resource-adequacy costs

Order 1920 and LTTP does not address inefficient siloed planning



Consolidation of siloed existing (near- and long-term) processes with new Order 1920 process will be needed to achieve effective proactive planning

These solely reliability-driven processes account for > 90% of all US 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 will be enhanced by Order 1920 minimum requirements

- At least 7 distinct benefits (cost savings and reliability) considered

Interregional planning processes are large ineffective

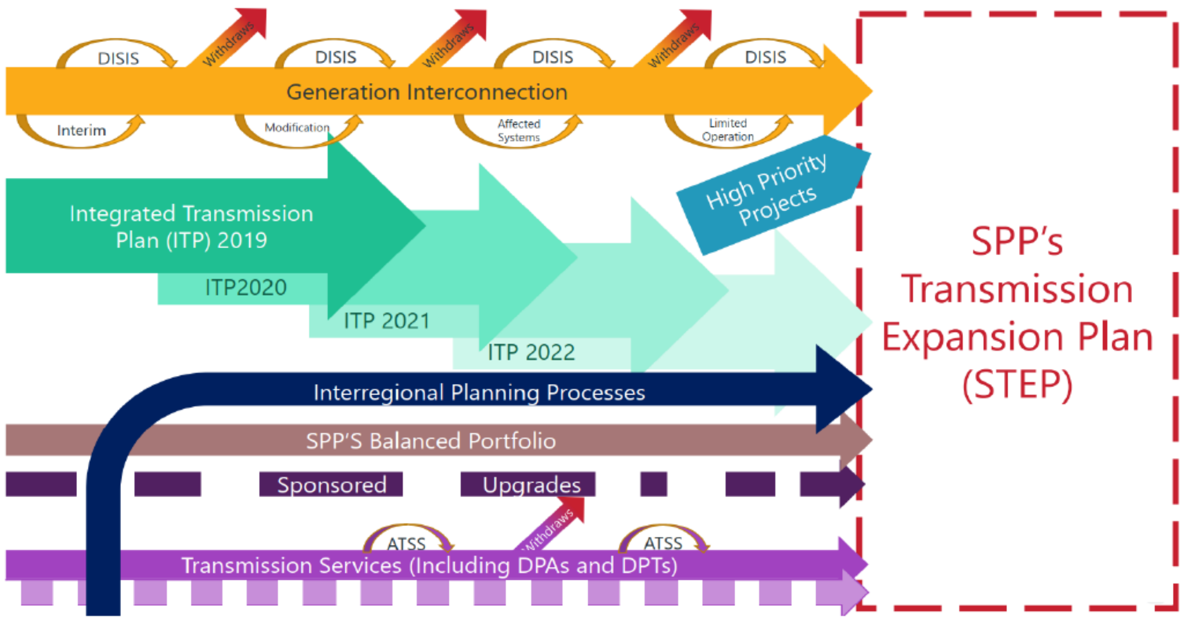
- Numerous national studies show more interregional transmission can reduce total system costs
- Order 1920 only addresses interregional coordination

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

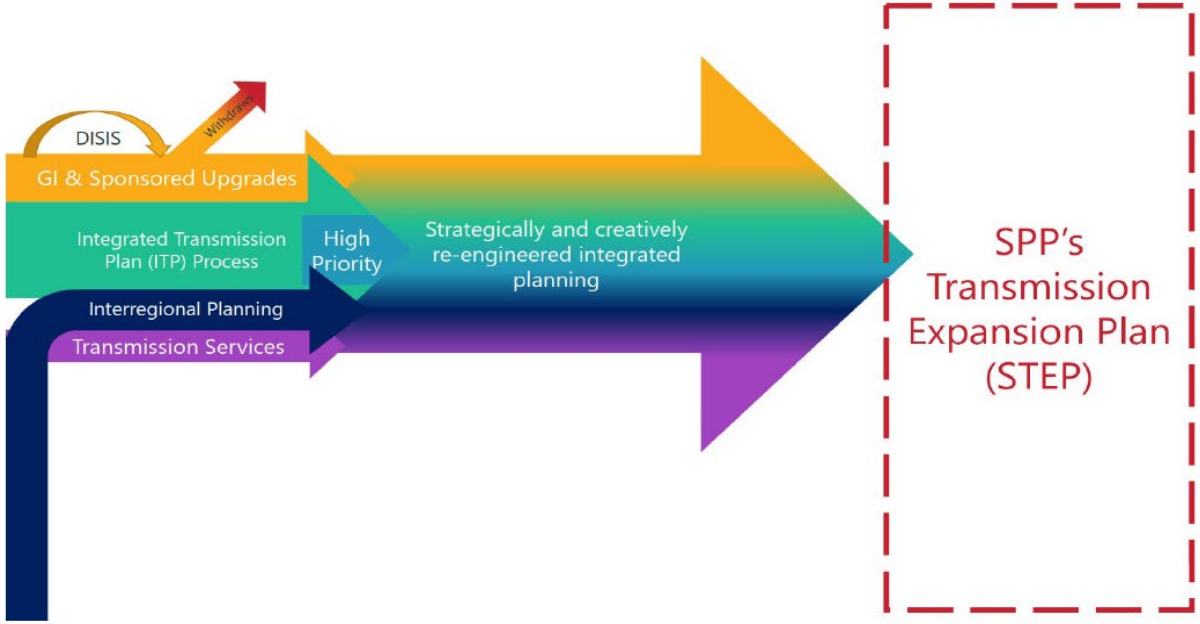
Example: SPP's Consolidated Planning Process (CPP)

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

Current Planning Process



New 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 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 comprehensive benefit quantification (beyond 7 benefits and understated quantification)
3. Consolidate siloed (near- and long-term) 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.

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 better 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 (particularly any with signed interconnection service agreements)

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

A “Loading Order” is needed to double transmission capacity more quickly and cost-effectively (with lower rate impacts)

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

UK NESO, Beyond 2030 Report, 2024, p. 26 (optimize existing grid before new infrastructure)

RAS and Advanced Grid Technologies: Fast and cost-effective

Unlike grid operators in the Western US, eastern grid operators under-utilize "remedial action schemes" (RAS) that can quickly and reliably enable increased grid utilization

- Example: CAISO identified 21 GW of energy-only (16 GW of deliverable capacity) generator interconnection headroom that could be created quickly, inexpensively, and reliably with RAS

Advanced and grid-enhancing transmission technologies (ATTs/GETs) can (1) significantly and quickly increase the capability of the existing grid, (2) offer low-cost solutions to address near-term reliability needs, and (3) also make new transmission more valuable and cost effective in the long-term

- Increasingly well-tested and commercially-available technologies include: dynamic line rating, smart wires and flow control devices, grid-optimized storage, topology optimization, advanced conductors
- See: MA CETWG report, CurrENT's report, topology optimization case studies, EPRI on GETs and TTO report

Consideration of RAS and GETs needs to be expanded beyond addressing operational and congestion needs – they should be part of the standard set of available solutions to address generation interconnection and both short- and long-term transmission planning needs

- As low-cost solutions to address reliability needs identified in generation interconnection and near-term planning
- In long-term multi-value planning to make new transmission more cost effective and valuable, reducing system-wide costs

Improve incentives to control project costs and deploy lower-cost solutions

Expanded use of cost-control incentives is advisable. Examples include:

- **Broad-based** performance-based ratemaking (PBR),
    - UK incentives for transmission providers (for both investments and operations) under "RIIO"
    - Australian incentive schemes for networks: efficiency benefits sharing scheme (EBSS), capital expenditure sharing scheme (CESS), and service target performance incentive scheme (STPIS)
- **Project-specific** cost-control and targeted cost-sharing incentives
    - Hard or soft cost caps (with adjustments for some uncontrollable factors)
        - Examples: NJ SAA Evaluation Report, Appendix E
    - Shared savings incentives for project cost (and schedule) under/overruns
        - Australian 70/30 sharing scheme (for realized vs. forecast costs) under CESS
        - NY PPTN: at least 80/20 sharing strongly encouraged (NYISO tariff at 31.4.5.1.8.3, FERC order, recent award)
        - Proposed shared savings incentives for GETs (e.g., link1, link2)
    - The project-specific "baselines" of expected costs can be: (1) competitive bids, (2) independent cost estimates, or (3) menu-based "revealed expectations" mechanisms
- **Cost reviews** of significant overruns
    - Australian targeted ex-post review process

Better outcomes through ISO-NE LTTP competitive procurements

NESCOE initiated the first competitive procurements of transmission needs under ISO-NE's promising new Long-Term Transmission Planning (LTTP) process

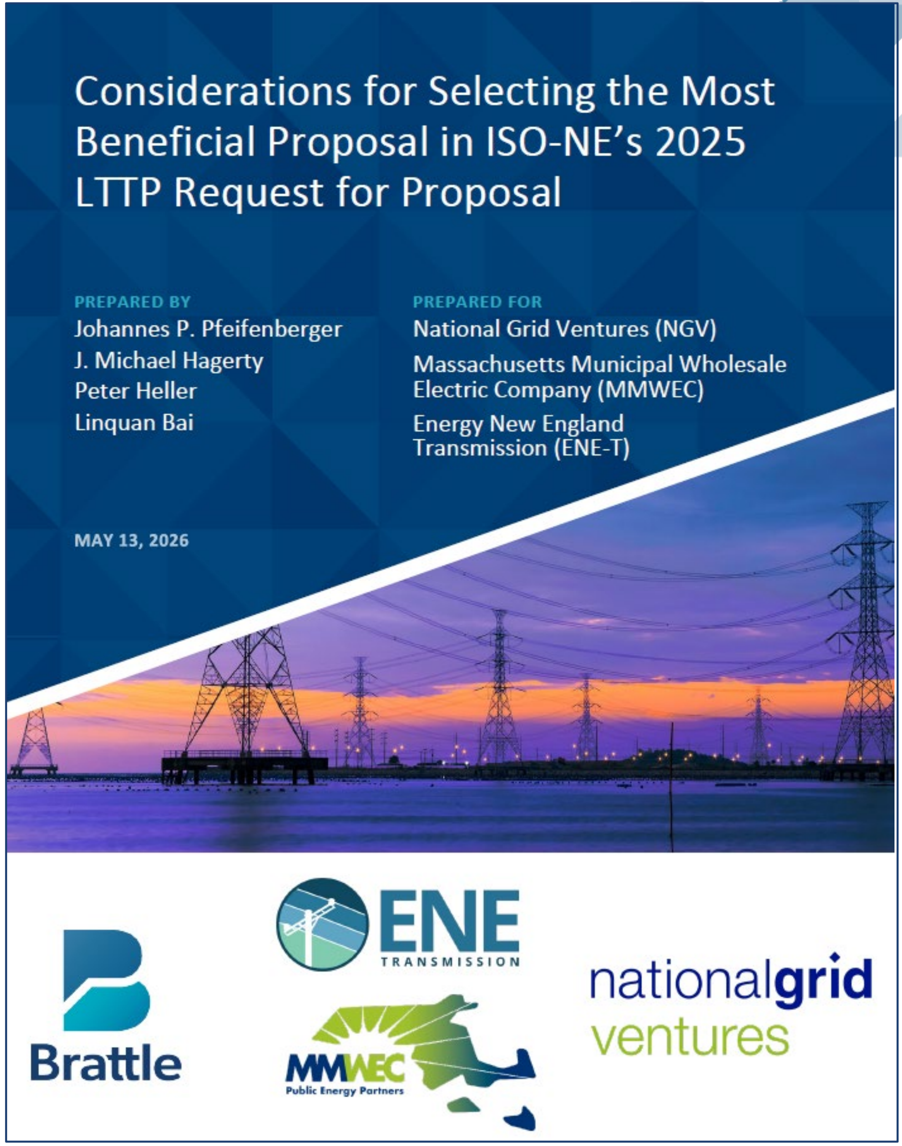
- Received 6 proposal to address the 2 transmission interfaces in Maine
- Several "expanded scope" proposals (encouraged by NESCOE, but possibly disqualified by ISO-NE) offer additional transfer capabilities and upgrades to other constraints already identified as 2035-40 needs

Our review of ISO-NE evaluation process found:

- Quantitative benefit metrics used will understate customer savings, particularly for expanded-scope proposals
  - Example: avoided major 2035-40 transmission upgrades to N-S interface and Boston import constraint are not captured in quantitative evaluation metrics
- Risks selection bias toward lowest-cost, lower benefit proposals that will require more piecemeal additional upgrades at higher total costs

Recommendations:

- Sensitivity analysis to estimate value of benefits not captured so sufficient weight can be given to specified (qualitative) additional evaluation factors'


Considerations for Selecting the Most Beneficial Proposal in ISO-NE's 2025 LTTP Request for Proposal

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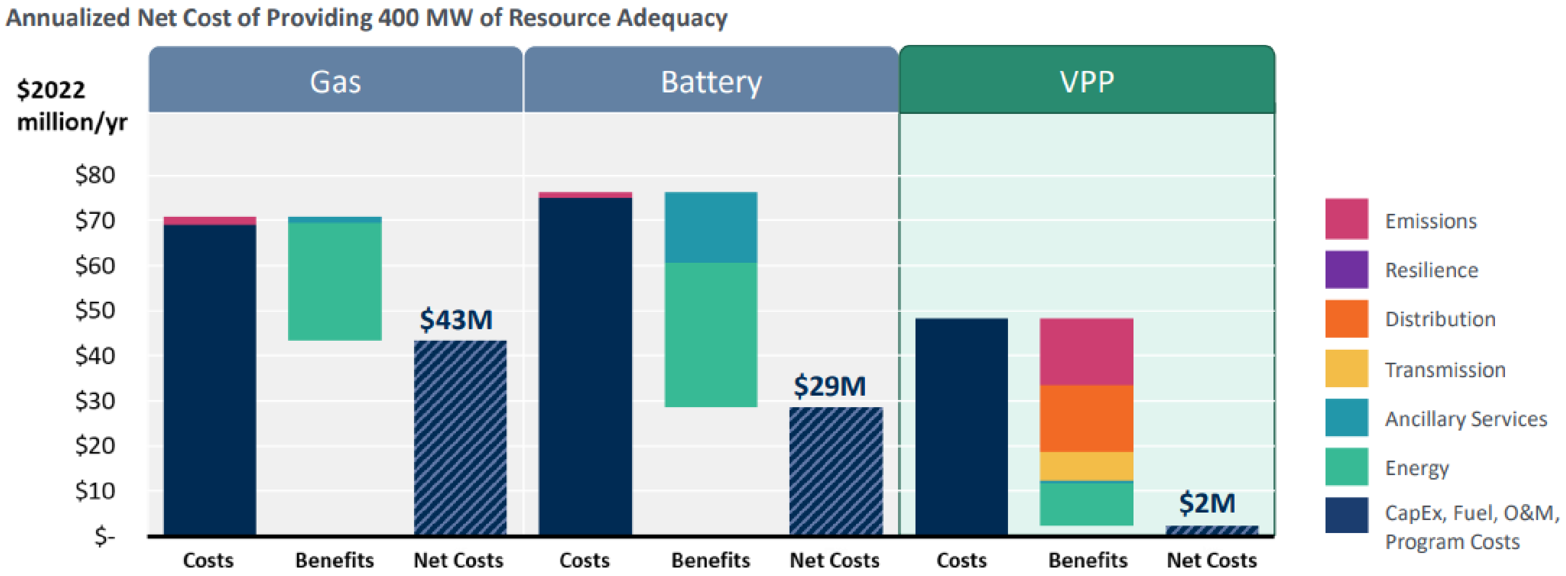
MAY 13, 2026

Efficiency and demand flexibility to reduce G+T+D costs

Electrification is quickly increasing electricity demand and system peak loads … <u>and</u> offers substantial opportunities to more cost-effectively meet system needs

- Most electrification demand is <u>flexible</u> (suitable for Virtual Power Plants or VPPs)
  - Examples: Electric vehicles (including V2G), building HVAC, thermal storage, solar+storage, data centers, H2
- Many electrification loads and distributed energy resources (DERs) are <u>highly controllable</u>
  - RMI: 60 GW of <u>dispatchable</u> VPPs can be developed by 2030 to provide RA and flexibility/operational reliability

Example: VPPs offer <u>resource adequacy</u> at (1) significantly <u>lower cost</u> and (2) <u>without delays</u> in generator interconnection. **Need planning/interconnection/operations to take advantage of it!**



Source: Hledik and Peters, Real Reliability: The Value of Virtual Power (Brattle, May 2023)

Conclusions and main opportunities

Relative to its size, New England has invested more in transmission than any other U.S. region, creating a grid that is almost congestion free. This means:

1. **There should be disproportionate opportunities to get more out of the existing grid**
   - Further improve generator interconnection and surplus/replacement process
   - Grid planning and operations to take advantage of RAS, GETs, ATTs
2. **New transmission should be planned more proactively and holistically**
   - Focus on robust (less incremental) transmission solutions that more cost-effectively address a broader range of near-and long-term transmission needs (less focused on just reliability)
   - Always evaluate if refurbishments of aging infrastructure can be upsized to address future needs

Taking advantage of these opportunities will require active collaboration between ISO-NE, utilities, policymakers, regulators, and market participants

Thank You!

Additional Slides

About the Speakers

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(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.

ISO-NE LTTP competitive bids received (Brattle Report)

FIGURE ES-1. MINIMUM REQUIREMENTS AND. EXPANDED-SCOPE PROPOSALS

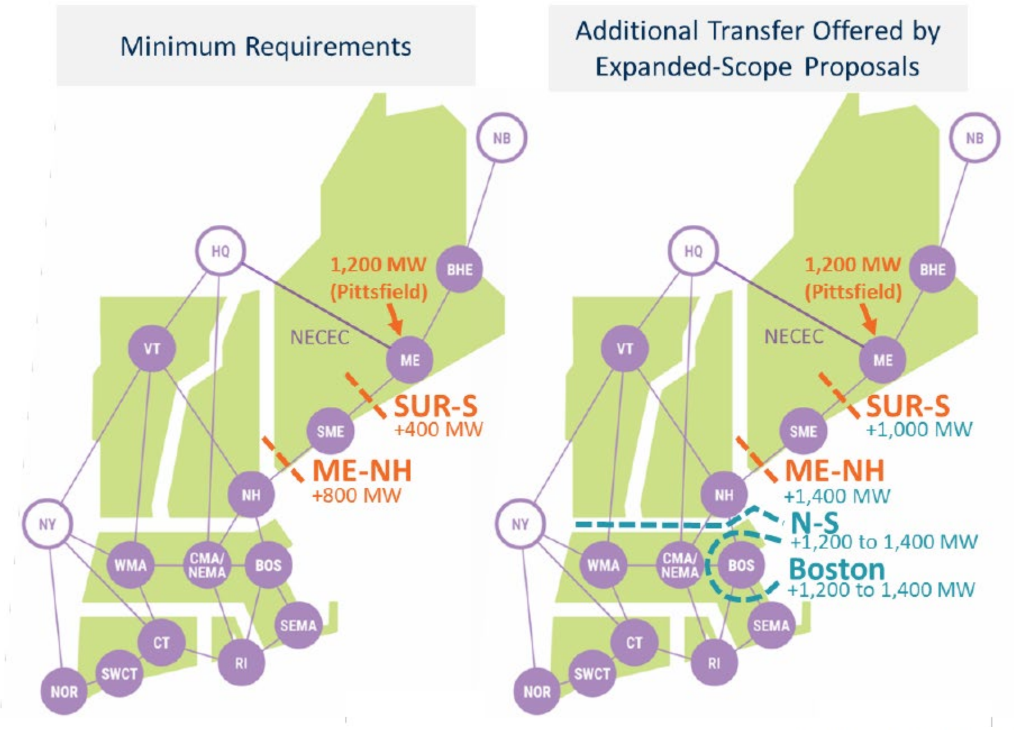
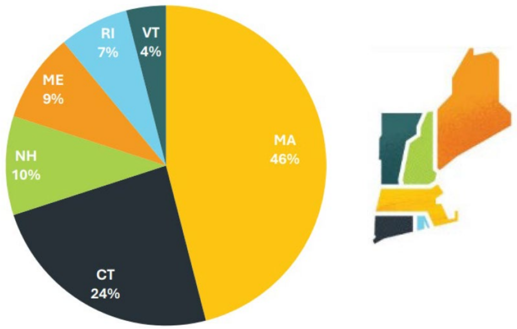


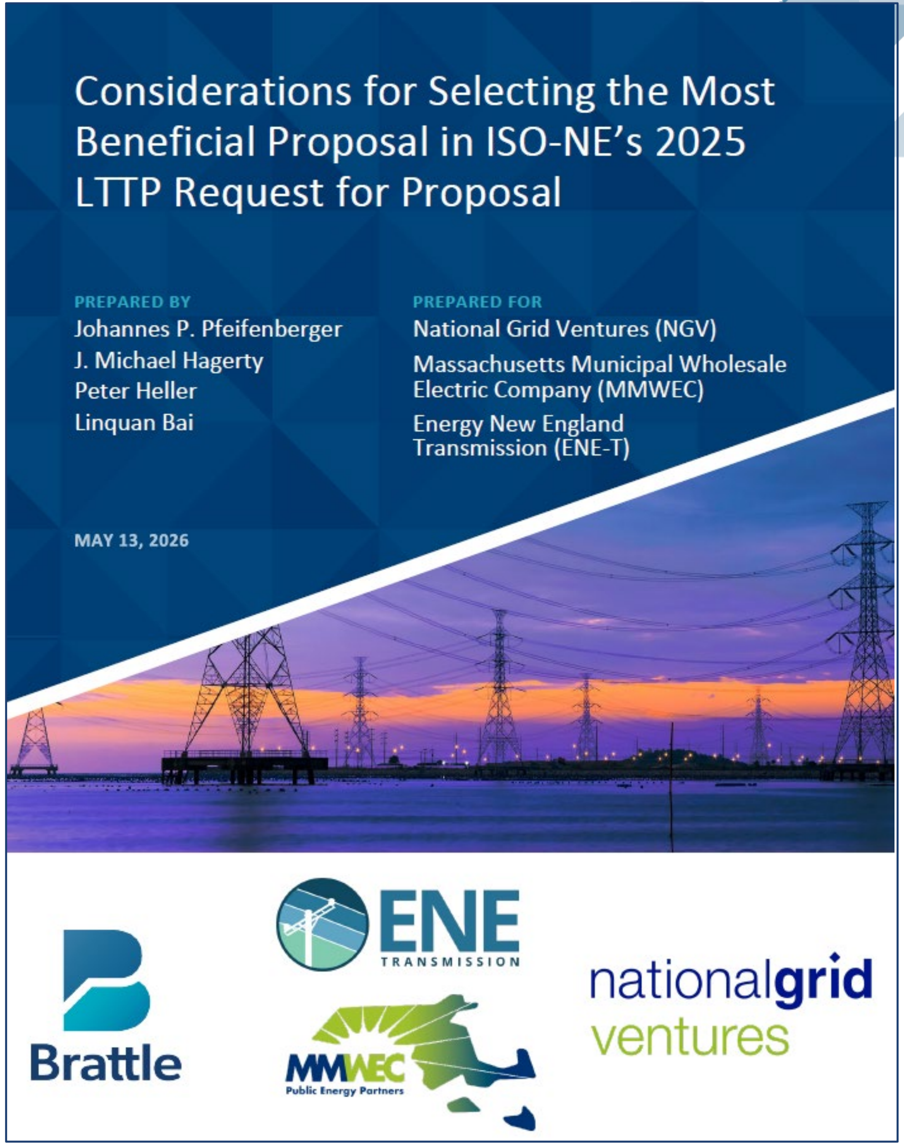
TABLE 1. SUMMARY OF 2025 LTTP PROPOSALS RECEIVED

ID	Type	Short Desc	Cost[4]	ISD
A1	AC	ME/NH AC #1	$2.20B	Q4 2032
A2	AC	ME/NH AC #2	$2.14B	Q4 2032
B1	DC	Maine-Mass DC	$4.04B	Q2 2035
C1	AC	ME/NH AC #3	$0.96B	Q2 2035
D1	DC	Wiscasset-Wakefield DC	$2.60B	Q3 2035
D2	DC	Wiscasset-Everett DC	$2.55B	Q3 2035

FIGURE 3. DEFAULT LTTP TRANSMISSION COST ALLOCATIONS



Source: 2025 LTTP RFP Longer-Term Proposal Summary, p. 7.



Major Grid Challenges Looking Forward

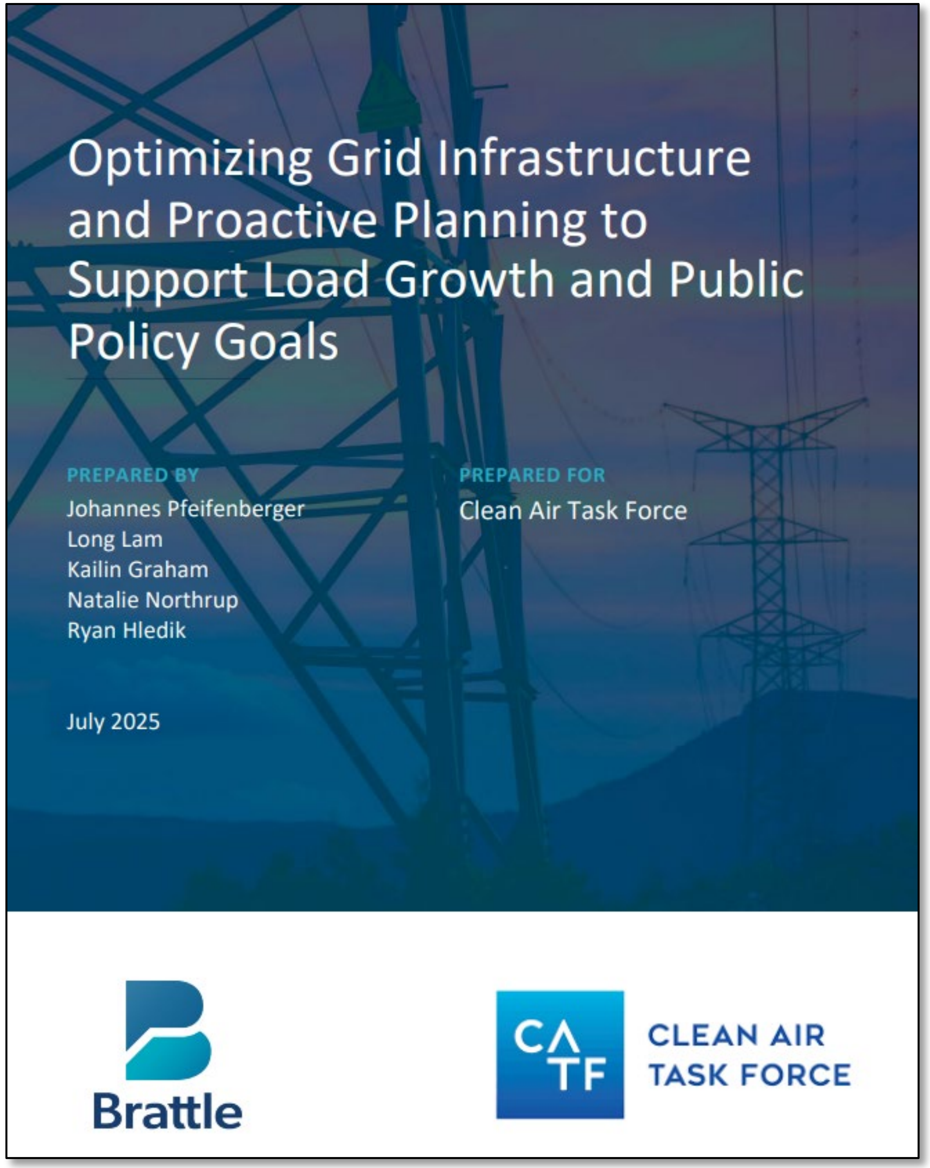
The US electric power system is entering a period of rapid and transformational change due to:

- 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

<u>Key question</u>: 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

How to Support Load Growth and Policy Goals Quickly and Efficiently

- I. Maximize the Value of Existing Power System
- II. Cost-Effectively Accelerate New Grid Connections
- III. Implement Proactive Planning & Procurement
- IV. Introduce Targeted Affordability Measures

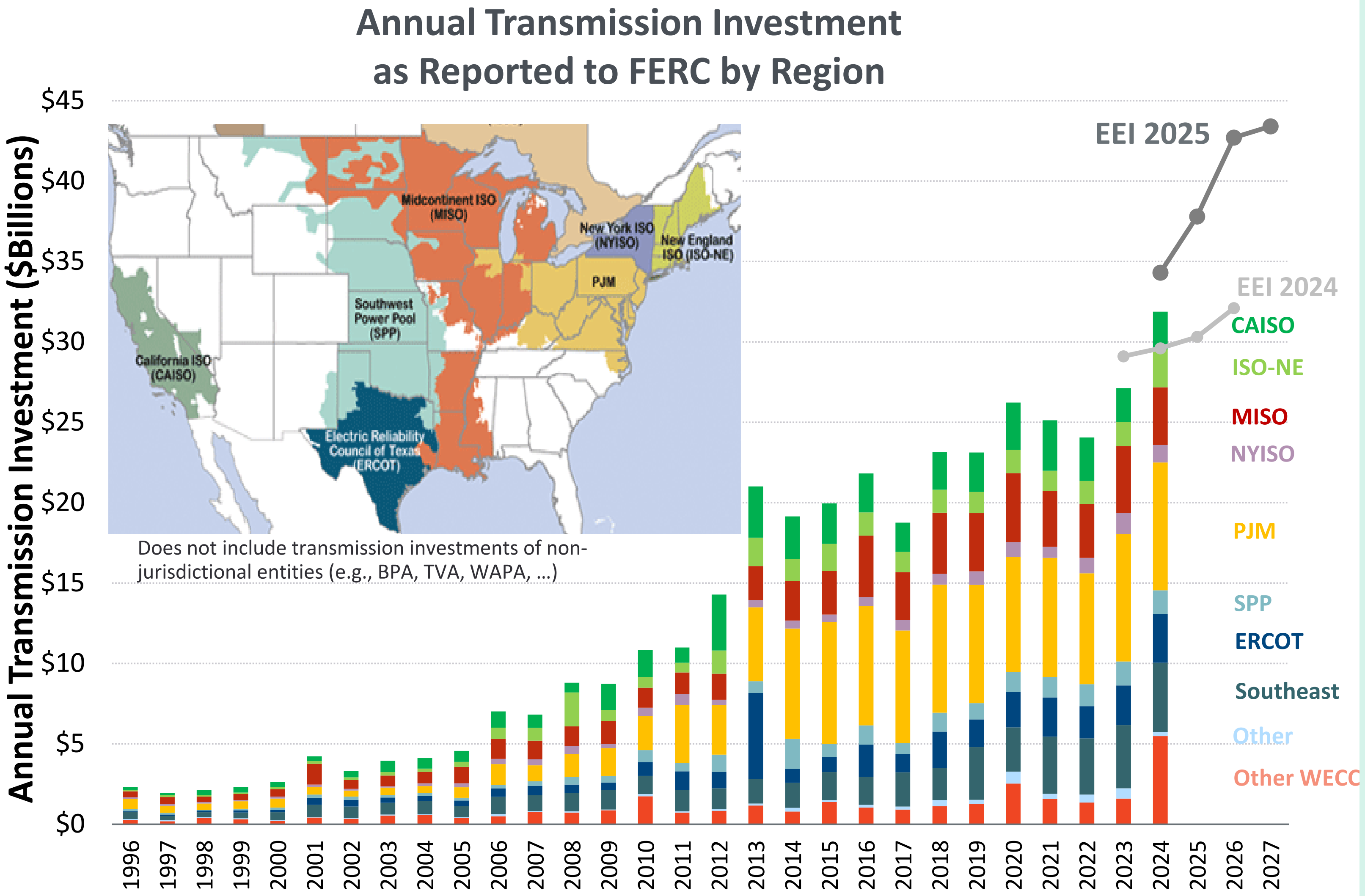
For each of these key areas, the full report offers case studies, cross references to industry experience and commercially-available technologies, and a discussion of best practices.

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.)

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

Total US transmission investment has increased from $3 to $30 billion in the last 30 years!

- About 90% of it is justified solely based on reliability needs (without benefit-cost analysis)
- About 50% based on “local” utility criteria (aging assets; without going through regional planning processes)
- Other than in MISO, only a few projects are justified based on multi-driver planning in other regions
- Essentially no interregional transmission is being planned (other than by merchant developers)

Proactive, Multi-Driver, Scenario-based Planning

Experience with proven transmission planning practices show they reduce total costs and mitigate risks by comprehensively addressing both near- and long-term needs:

1. **Proactively plan for all future generation- and load-serving needs** by incorporating realistic projections of the anticipated generation mix and locations, public policy mandates, load levels, and load profiles over the lifespan of the transmission investments
2. **Use multi-driver planning and account for the full range of transmission projects' benefits** and to comprehensively identify investments that cost-effectively address all categories of needs and benefits
3. **Address uncertainties and high-stress grid conditions explicitly through scenario-based planning** that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events
4. **Use comprehensive transmission network portfolios** to address system needs and cost allocation more efficiently and less contentiously than under a single-driver, project-by-project approach
5. **Jointly plan inter-regionally across neighboring systems** to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

See: Brattle and GridStrategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

Examples of Proactive, Scenario-based Planning Processes

Although still rarely used, significant experience exists with proactive, multi-driver (multi-benefit), scenario- and portfolio-based transmission planning:

	Proactive Planning	Multi-Benefit	Scenario-Based	Portfolio-Based	Interregional Transmission
CAISO TEAM (2004)[146]	✓	✓	✓		
ATC Paddock-Rockdale (2007)[147]	✓	✓	✓		
ERCOT CREZ (2008)[148]	✓			✓	
MISO RGOS (2010)[149]	✓	✓		✓	
EIPC (2010-2013)[150]	✓		✓	✓	✓
PJM renewable integration study (2014)[151]	✓		✓	✓	
NYISO PPTPP (2019)[152]	✓	✓	✓	✓	
ERCOT LTSA (2020)[153]	✓		✓		
SPP ITP Process (2020)[154]		✓		✓	
PJM Offshore Tx Study (2021)[155]	✓		✓	✓	
MISO RIIA (2021)[156]	✓	✓	✓	✓	
Australian Examples:					
- AEMO ISP (2020)[157]	✓	✓	✓	✓	✓
- Transgrid Energy Vision (2021)[158]	✓	✓	✓	✓	✓

(See specific examples for SPP, MISO, CAISO, AEMO, and ENTSO-E in additional slides)

Source: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (brattle.com)

Scenario-based planning: Explicitly recognize an uncertain future

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

This type of 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 Using Scenario Planning to Reshape Strategy (MIT Sloan Management Reivew)

Least-regrets Planning: How can risks be mitigated?

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)?

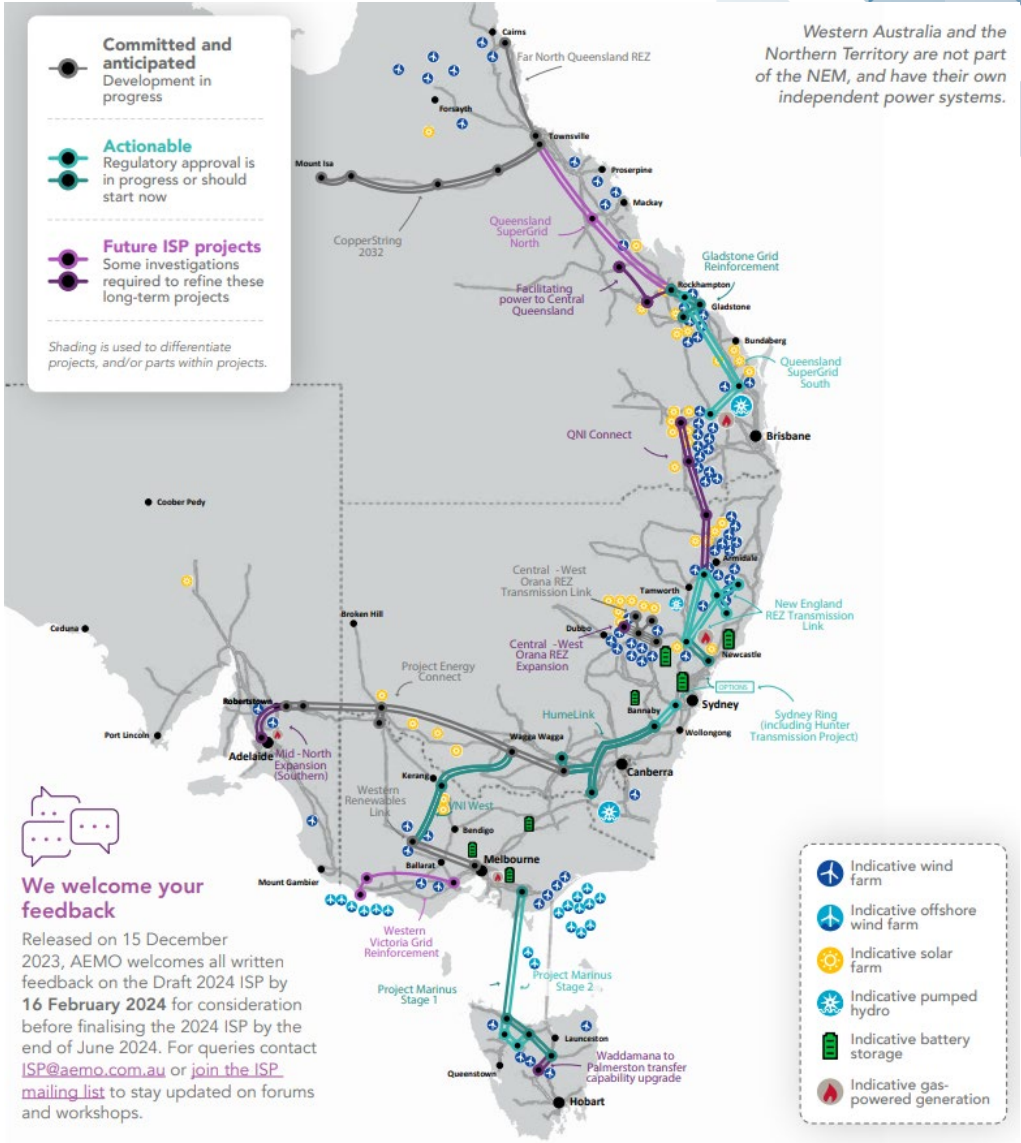
This is what least-regrets planning should focus on!

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 but flexible** 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)
  - **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)
  - **Both near- and longer-term needs:** (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
- **Guidelines** for cost-benefit framework, forecasting, and "investment tests" from the Australian Energy Regulator (AER) make AEMO plans actionable (link)

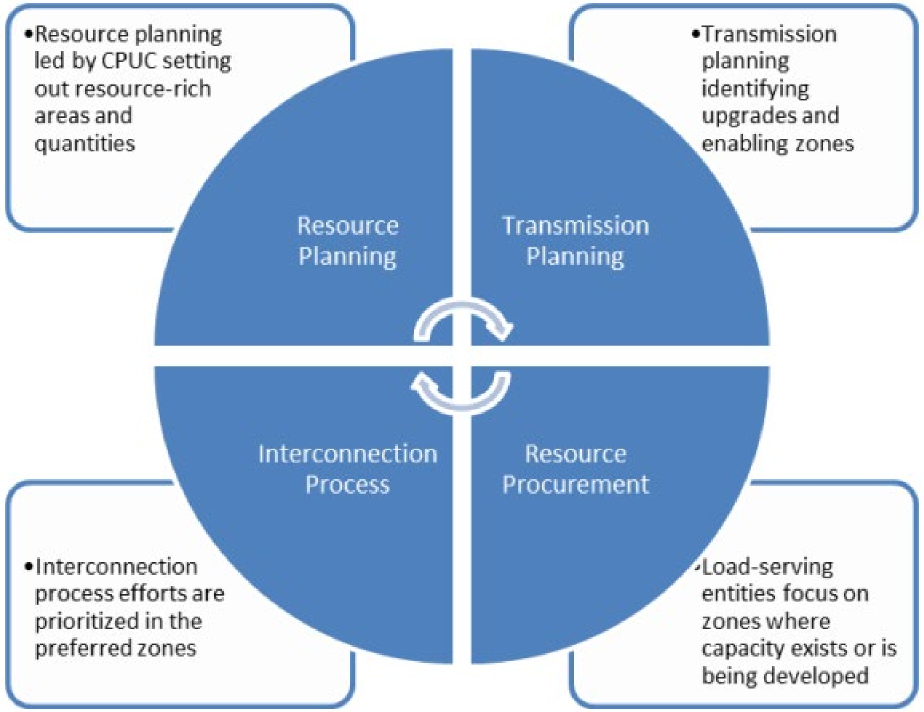


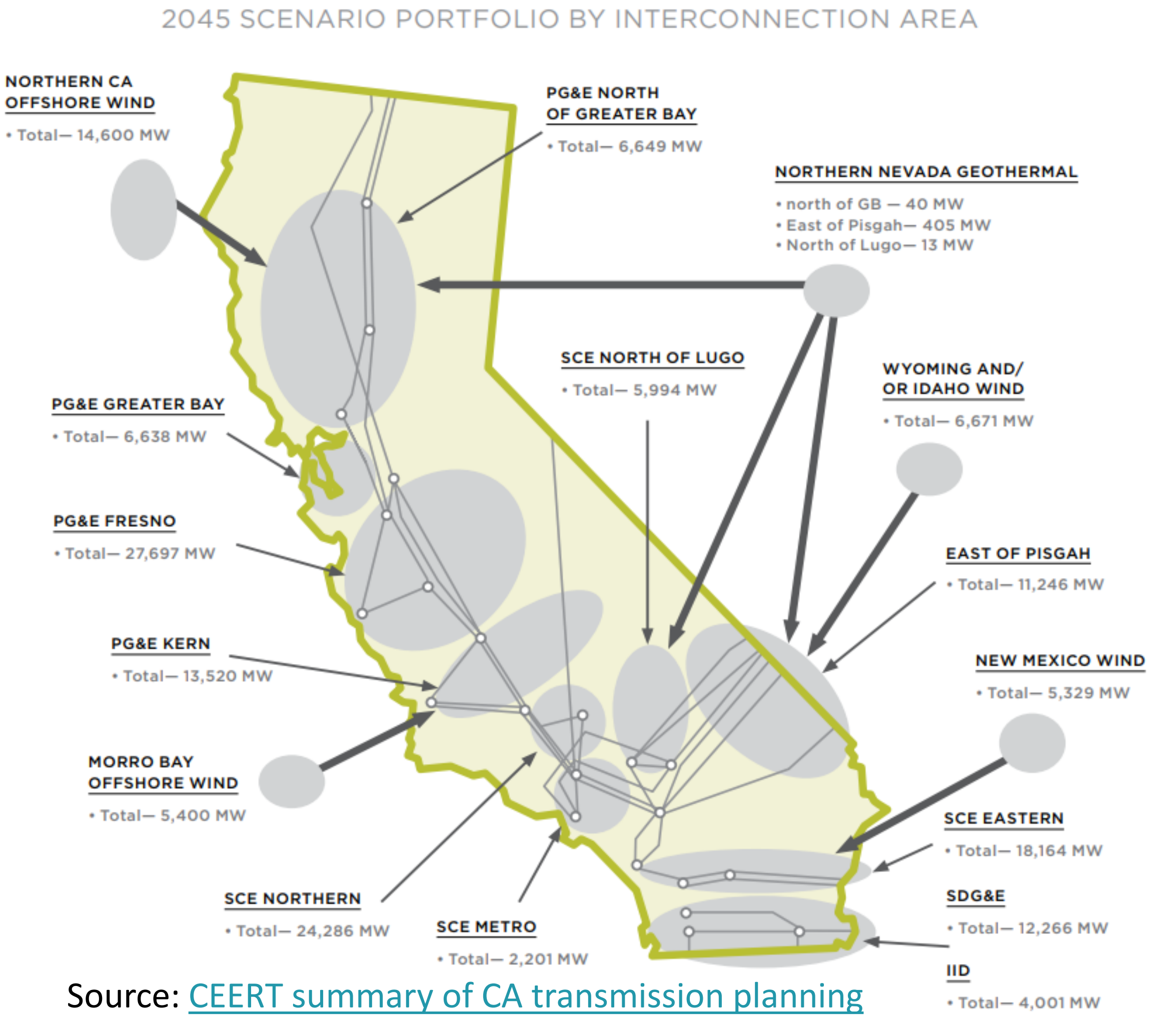
Source: AEMO | Draft 2024 ISP Consultation

California's Transmission Planning Process (TPP)

California's TPP combines (1) scenario-based, zonal resource development outlooks prepared by state agencies with (2) the planning and procurement of transmission solutions by the California ISO

- See overview and board-approved 2022-2023 Plan
- Improved generator interconnection process (link) offers substantial headroom





Source: CEERT summary of CA transmission planning

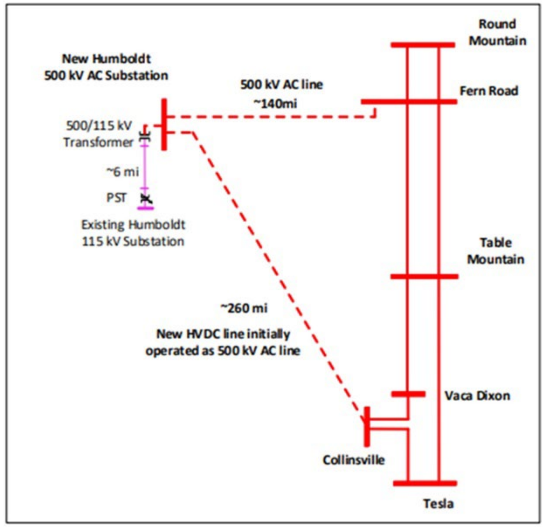
Examples: Flexible solutions to reduce costs and minimize regrets

Planning processes need to develop more flexible (lower-regret) generation and grid 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:

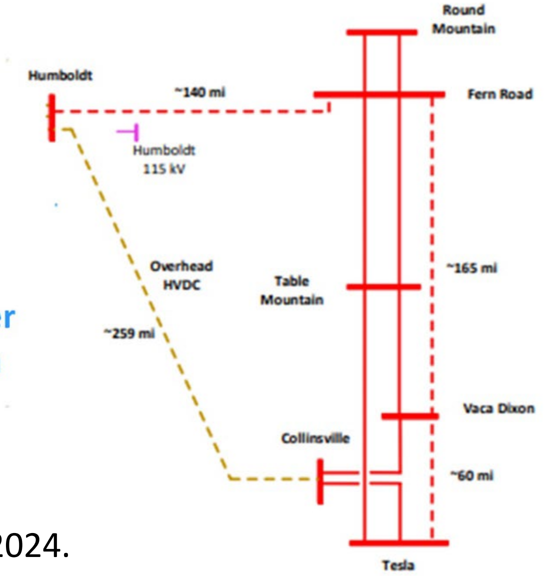
Two new 500kV lines, of which one is "HVDC-ready"

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



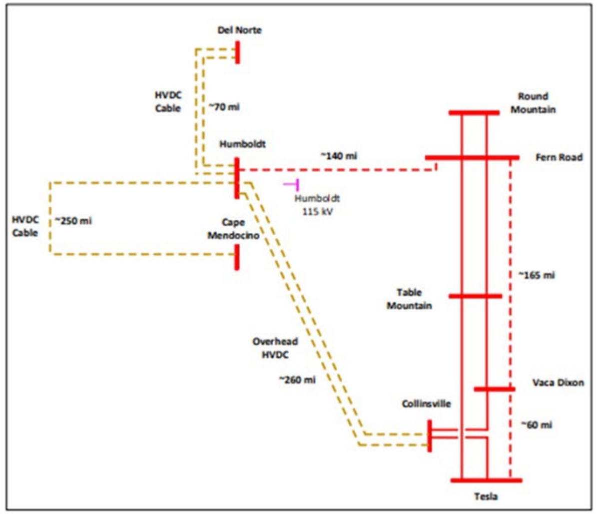
Add DC converter stations to each end of the line

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 interconnecting resources more quickly and efficiently

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?

- PJM has 40+ GW of existing POIs (with CIRs) at retiring plants! … most of which are in attractive locations for new storage, renewables (e.g., as noted in the ICC draft REAP report), and natural gas plants (Example: client rejected new solar+storage bid at retiring fossil plant because getting ISA would take 5-6 years)
- More quickly assign POIs built under State Agreement Approach to generators procured by states (e.g., NJ)
- Sharing POIs is attractive: many aging resources are rarely dispatched when renewable generation is high

Examples:

- Separate MISO and SPP processes for 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)

Options for interconnecting resources more quickly and efficiently

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 any 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

Order 1920's enhances "Interregional Transmission Coordination"

As FERC's Explainer states: "Order No. 1920 requires transmission providers in neighboring transmission planning regions to modify their existing **interregional transmission coordination procedures** to align with long-term regional transmission planning reforms. Order No. 1920 established the following requirements to adapt existing procedures with this requirement.

1. Require transmission providers to share information regarding long-term transmission needs and **identify and jointly evaluate interregional transmission facilities** to address those needs
2. **Allow entities to propose** interregional transmission facilities as more efficient or cost-effective solutions to long-term transmission needs

Transmission providers are mandated to make the following information publicly available through their website or e-mail list to **enhance transparency and information sharing**.

1. Long-term transmission needs discussed in interregional transmission coordination meetings
2. Interregional transmission facilities proposed or identified as part of long-term regional transmission planning
3. Details such as voltage level, estimated cost, and estimated in-service date of proposed interregional transmission facilities
4. Results of cost-benefit evaluations for such interregional transmission facilities, including overall benefits and region-specific benefits
5. Selection of interregional transmission facilities to meet long-term transmission needs, if any

These reforms aim to ensure that identified long-term transmission needs are considered in interregional coordination and cost allocation processes, thereby promoting fair rates."

Why interregional transmission and what's holding us back?

Q: Why interregional transmission? A: It is uniquely beneficial

- Larger geographic footprint offers more substantial diversity-related economic and reliability value
  - Capturing full (load and resource) diversity value requires a grid that is larger than the weather
- Peak-load and resource availability diversity = reduced regional resource adequacy requirements
- Temporary lower-cost/surplus generation in a region can be be shared across larger footprint
- Larger scale of interregional solutions can be more cost effective than multiple regional solutions

Q: Why don't we see much of it getting planned? A: Many barriers (slide 21)

- No defined interregional reliability standards or planning requirements
- Each region prefers meeting its reliability needs on its own
- Largely ignored in RTOs' regional multi-value planning processes
- Addressing local needs before regional, and regional needs before interregional, pre-empts more cost-effective interregional opportunities
- ISOs prefer to avoid the added complexity of multi-regional coordination and cost allocation
- <u>Result</u>: only merchant transmission developers have been proposing major new interregional projects

“Transmission Benefits” – what are they?

Multi-value transmission planning allows the selection of transmission solutions that offer the greatest net benefits

- But what are these (often abstract) “transmission benefits”?

Transmission benefits = Cost savings (or better reliability) offered by the upgrade

Examples of savings from right-sized, multi-value transmission investments:

- Enable lower-cost generation to displace higher-cost generation = production cost savings
- Reduce need for reserve capacity through geographic diversification = investment cost savings
- Avoid costs of other transmission upgrades or refurbishments = investment cost savings
- Allow generation construction in lower-cost areas/regions = investment cost savings
  (Note: this benefit is not in Order 1920’s list of seven required benefit metrics)

Bottom line: Sometimes you have to spend money to safe money!

New England ought to focus more on forward-looking “right-sizing” of aging asset refurbishments and avoiding piecemeal incremental upgrades

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, incl. benefits beyond Order 1920's 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

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

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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, et al., Considerations for Selecting the Most Beneficial Proposal in ISO-NE's 2025 LTTP Request for Proposal, for NGV MMWEC NEE-T, May 13, 2026.

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RENEW Northeast, A Transmission Blueprint for New England, Prepared with Borea and The Brattle Group, May 25, 2022.

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