Better Transmission Planning:
Proactive, Holistic, Scenario-based, Least-Regrets, with Portfolio-based Cost Allocations

PRESENTED BY

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PRESENTED AT

CREPC Order 1920 Ad Hoc Committee Meeting

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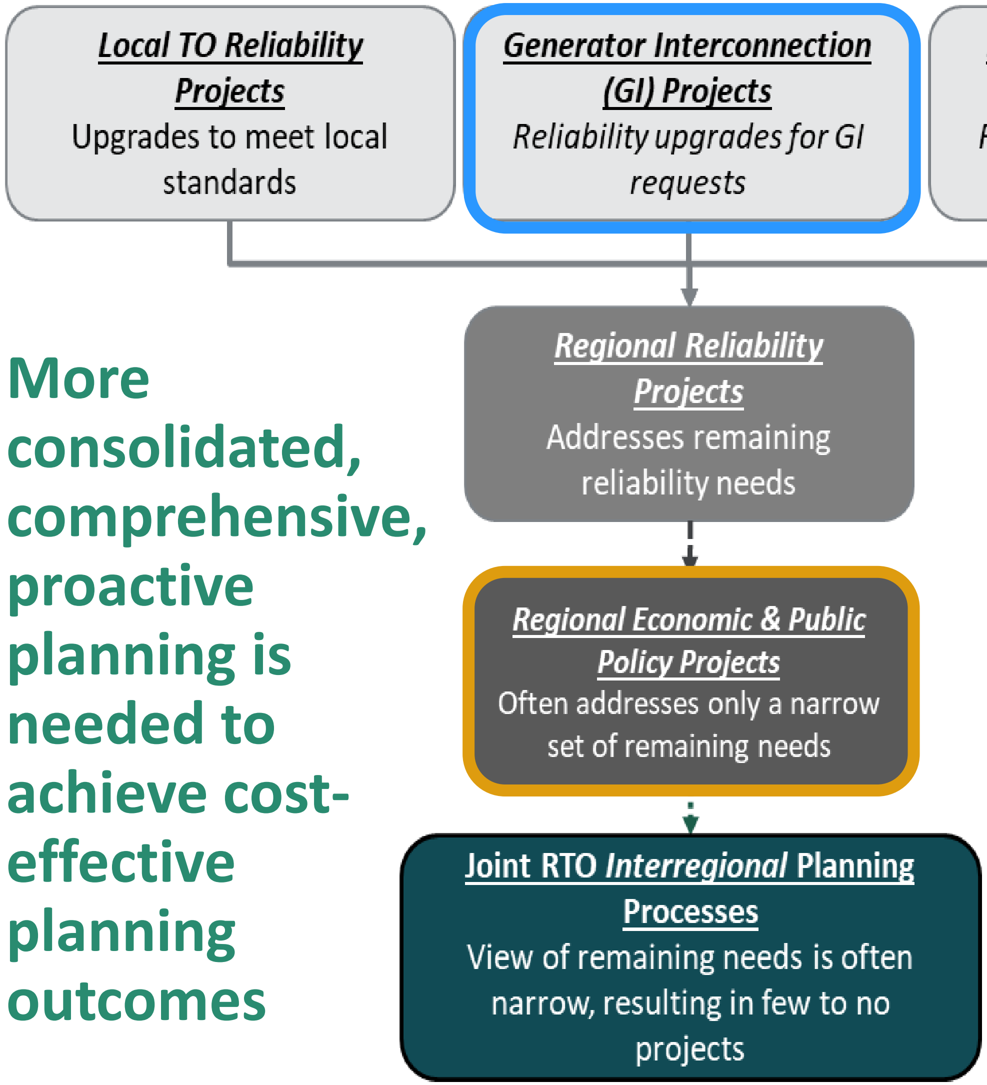
Brattle

Topics discussed today

1. Consolidating siloed planning processes
2. Order 1920 opportunities (beyond minimal compliance)
3. What is scenario-based planning?
4. What is least-regrets planning?
5. The benefit of portfolio-based (not project specific) cost allocations

Transmission planning is too siloed and reliability-focused



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.

More holistic (consolidated) transmission planning is needed!

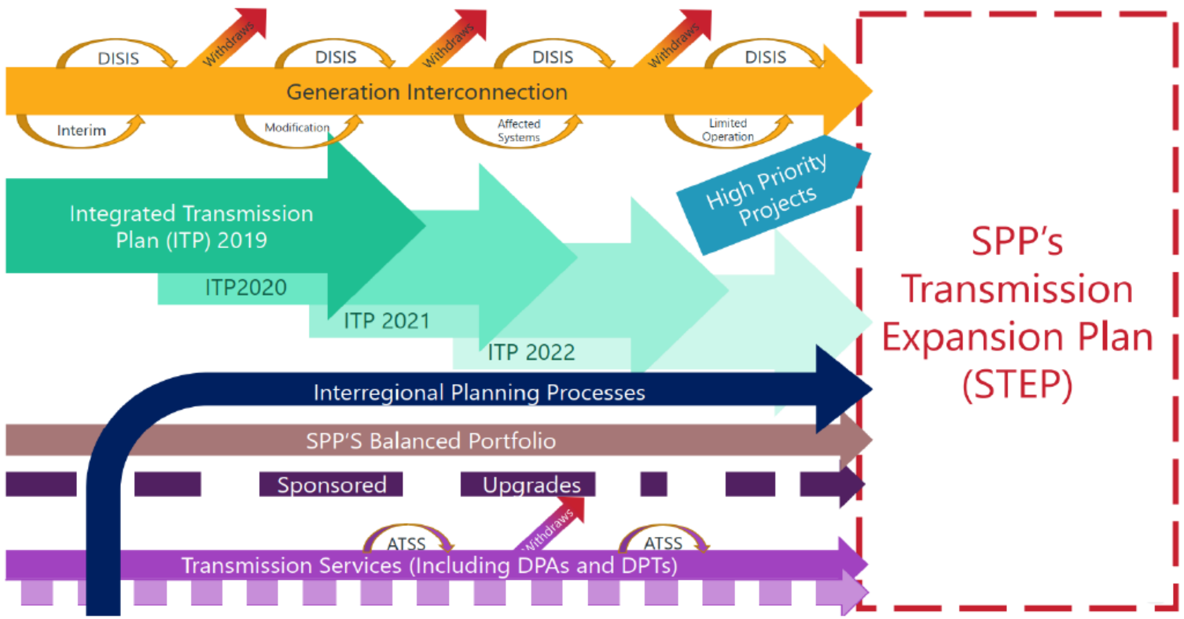
Improved transmission planning processes offer significant benefits (and overall cost savings) if they:

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

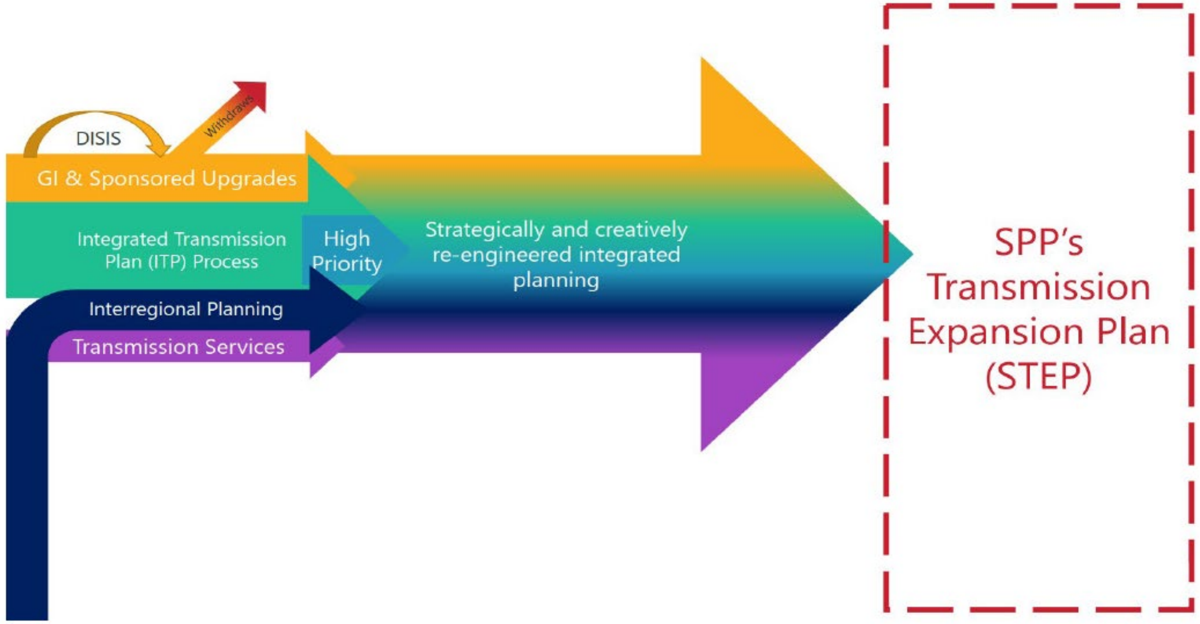
Example: SPP's proposed Consolidated Planning Process (CPP)

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

Current Planning Process



Proposed Consolidated Planning Process



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

FERC's Order 1920 leaves room for further improvements

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

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

Key planning tools for an uncertain future

(beyond transmission):

- Scenario based
- Flexible, least-regrets solutions

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

Potentially missing and understated benefits

Any framework for benefit-cost analysis needs to be flexible enough (not overly prescriptive) to explicitly allow for:

- Learning from the experience with quantifying transmission-related benefits (i.e., cost savings or reliability improvements) over time
- Consideration of all transmission-related benefits that can reasonably be documented and quantified (even if beyond those required in Order 1920 or pre-specified in tariffs and business practices)

The 7 benefits required in Order 1920 is not a complete list of benefits

- For example, FERC's ANOPR also considered: (8) diversification of weather and load uncertainty; (9) deferred generation capacity investments; **(10) access to lower-cost generation**; (11) increased competition; and (12) increased market liquidity.

While double counting needs to be avoided, many quantified benefits are understated:

- Example: **production cost savings** typically understated by 50+% because simulations that do not capture realistic congestion due to weather-normalized data, no transmission outages, and perfect foresight (i.e., no unexpected challenges during real-time market operations)
- Example: **extreme weather metrics** quantify only benefit avoiding loss of load events, but do not capture the high costs incurred during such events even when no load is shed

See also discussion in Proposal to Develop Optimal Transmission Planning in Alberta (2025)

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:

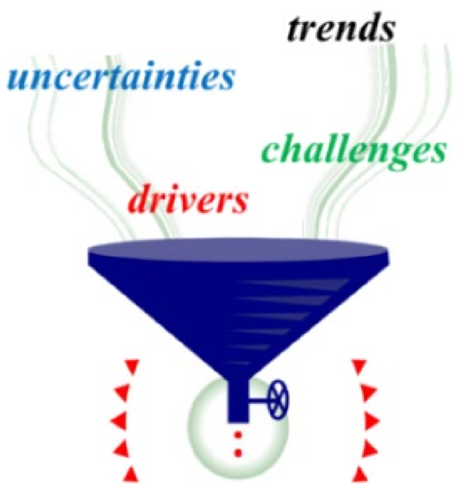
- Used by Shell with great success since the 1970s for long-term planning under large uncertainties
- **Allows planners to think, in advance, about the many ways the future may unfold and how to respond effectively and flexibly as uncertain future outcomes become reality**
- Ranks among the top-ten management 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)

Examples: TransGrids, ERCOT, WestTEC Scenarios for LT Planning



TransGrid (Australia) created and analyzed six scenarios of possible futures based on drivers and uncertainties related to: technology trends, energy policies, consumer preferences, decentralization, demand growth, market rules & regulations, and community expectations

Current trends

Ageing coal power stations are replaced with competitively priced large and small-scale renewables and storage

- Economic growth, immigration and energy efficiency are consistent with historic and projected growth rates under present trends, taking into account current projections for the recovery from COVID-19
- Electric vehicle, rooftop solar and behind-the-meter battery uptake is consistent with current central projections

Deep decarbonisation

Market forces, international and domestic politics and consumer expectations drive a huge reduction in carbon emissions across all sectors of our economy. Australia commits to limit global warming to 1.5°C, in line with the aspirations of the Paris Agreement

- Australia achieves net zero emission by 2035 and then net-negative emissions beyond
- Our electricity system is powered by 100% renewable energy from 2035
- Internal combustion engine vehicles are completely phased out by 2050, replaced primarily by electric vehicles
- Hydrogen is used for some domestic heavy-transport and industry applications and for peaking electricity generation

Prosumer power

Consumer choices and technology advancement drive a very high penetration of well-coordinated distributed energy resources into the energy system

- Extremely high uptake of rooftop solar, behind-the-meter storage and electric vehicles (many equipped with Vehicle-to-Grid capabilities)
- Artificial intelligence and automation enable the coordination of consumer devices to respond to local system and market conditions
- A net zero emissions economy is achieved by 2050

De-industrialisation death spiral

A global economic downturn causes Australia's economic growth to slump, particularly impacting the industrial sector

- Industrial electricity consumption in the NEM declines by 50% to 2025. Australia's aluminum and steel production facilities close by 2025
- Commercial electricity demand falls by 9% in the NEM before slowly growing in the 2040s

States go it alone

A breakdown of NEM regulations sees a siloed approach from the states which establish their own policies and local energy solutions. A regulatory impasse prevents new interstate transmission developments from proceeding

- New transmission links between states cannot be built, although existing links remain in use
- Each state must generate and balance its own electricity to maintain energy reliability
- Other modelling assumptions align to the **Current trends** scenario

Clean energy superpower

Australia leverages its abundant renewable energy resources and mineral ores to become a global clean energy superpower, exporting green hydrogen and metals to the world

- Australia's hydrogen sector grows to produce 19.2 million tonnes (MT) of hydrogen annually by 2050. This is broadly consistent with the high scenario from Australia's National Hydrogen Strategy
- 61% of the hydrogen produced is exported to our trading partners, 22% is used to produce green steel for export and 17% is for other domestic purposes
- Australian steel production increases significantly (from 0.3% to 5% of global steel output) and aluminum production (a five-fold growth)
- A net zero emissions economy is achieved by 2050

	Current Trends	Econ Boom	High Gas	Strict Env.
Gas Prices	Base	Low	High	High
CO2 Costs	Base	Low	Base	High
Renewable Costs	Base	Low	High	High
Inflation	Base	Low	Base	Base
Gross Load	Base	Low	Base	Low

ERCOT has been undertaking similar scenario development efforts for its long-term transmission system assessments (LTSAs) since 2014

WestTEC is in the process of doing the same

Source: Our Energy Vision | Transgrid, ERCOT Scenario Planning – Brattle, WestTEC CREPC-WIRAB Presentation

Risk mitigation through "least-regrets" planning

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

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

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

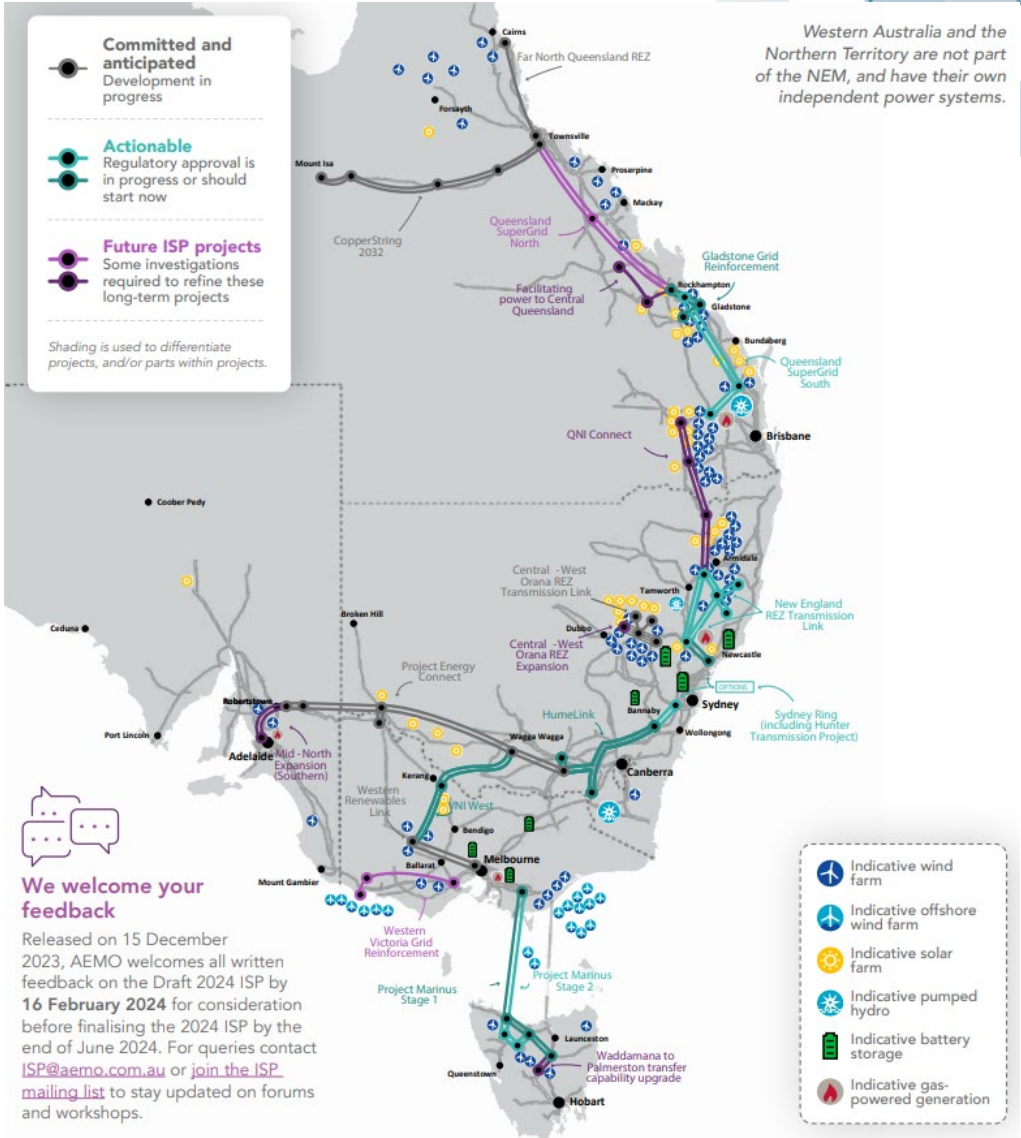
This is what least-regrets planning should focus on!

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

Example: Australian Integrated System Plan (ISP)

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

- **Clearly-specified 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

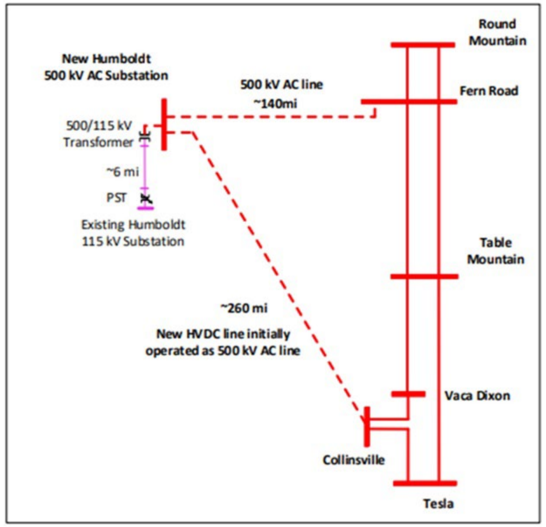
Examples: Flexible solutions to reduce costs and minimize regrets

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:

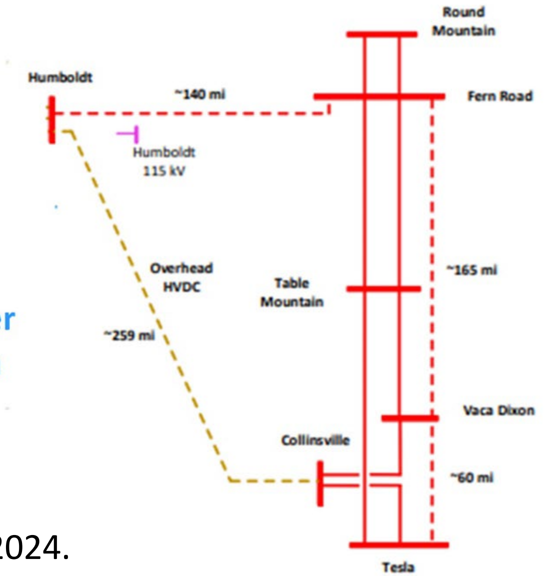
Two new 500kV lines, of which one is "HVDC-ready"

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



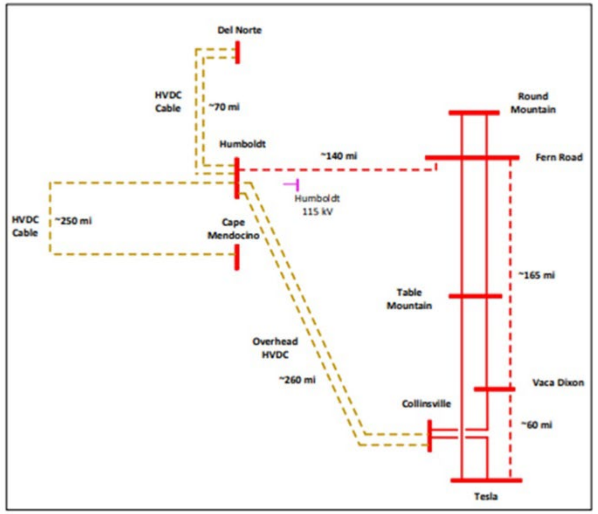
Add DC converter stations to each end of the line

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.

Portfolio-Based Cost Allocation: Advantages over Project-by-Project Allocations

FERC does not require that the cost of each project is allocated based on its benefits … as long as the cost allocation for a portfolio of projects is roughly commensurate with overall benefits.

Even postage stamp (load-ratio share) allocation is appropriate and acceptable if:

- All customers tend to benefit from class or group of facilities
- Distribution of benefits is likely to vary (but "average out") over long life of facilities

Portfolio-based cost allocations are less controversial and easier to implement

- **Portfolio-wide benefits tend to be more even distributed and more stable over time**
- **One cost allocation analysis for portfolio vs. many analyses for many projects**

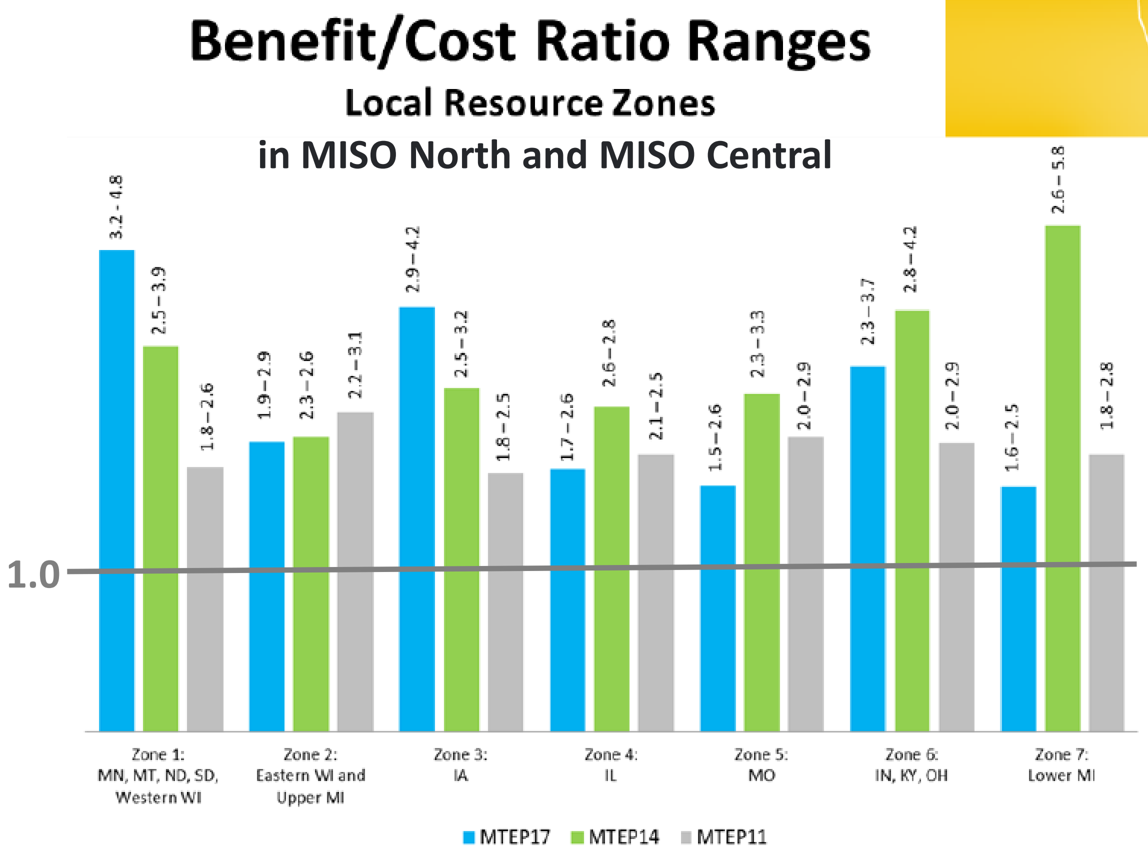
Examples of portfolio-based cost allocations:

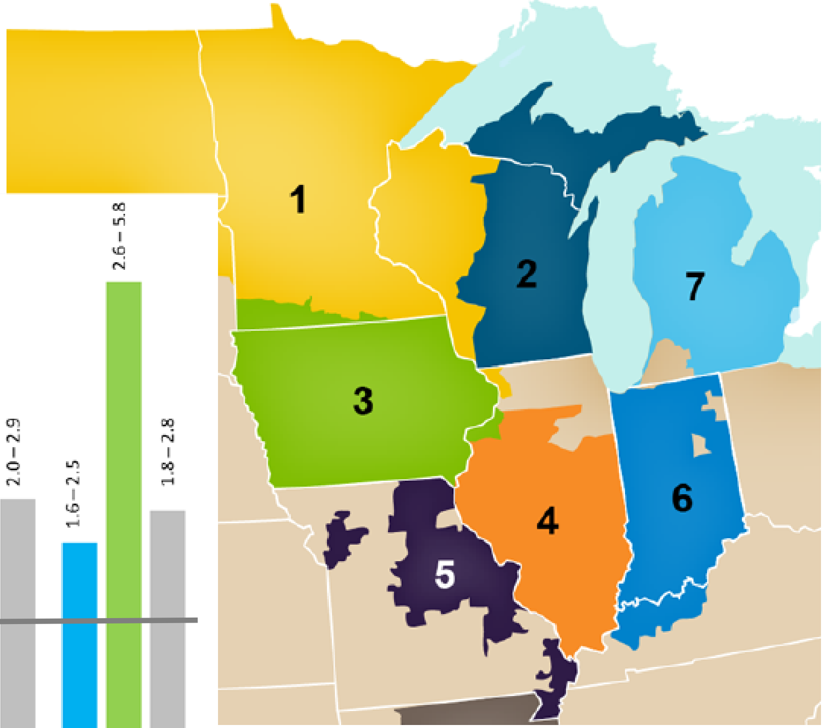
- SPP Highway-Byway (designed by RSC): Periodic review if benefits of all approved projects is roughly commensurate with costs of all projects
- MISO MVPs (with OMS input): Benefits of entire portfolio compared with allocated costs

Example MISO MVPs: Benefits of the portfolio (as a whole) significantly exceed postage-stamp-allocated costs in all regions

MISO's MVP Portfolio provides benefits across the MISO footprint that are roughly equivalent to (postage-stamp) allocated costs

- MISO quantified 6 types of economic benefits (plus reliability and public policy benefits)





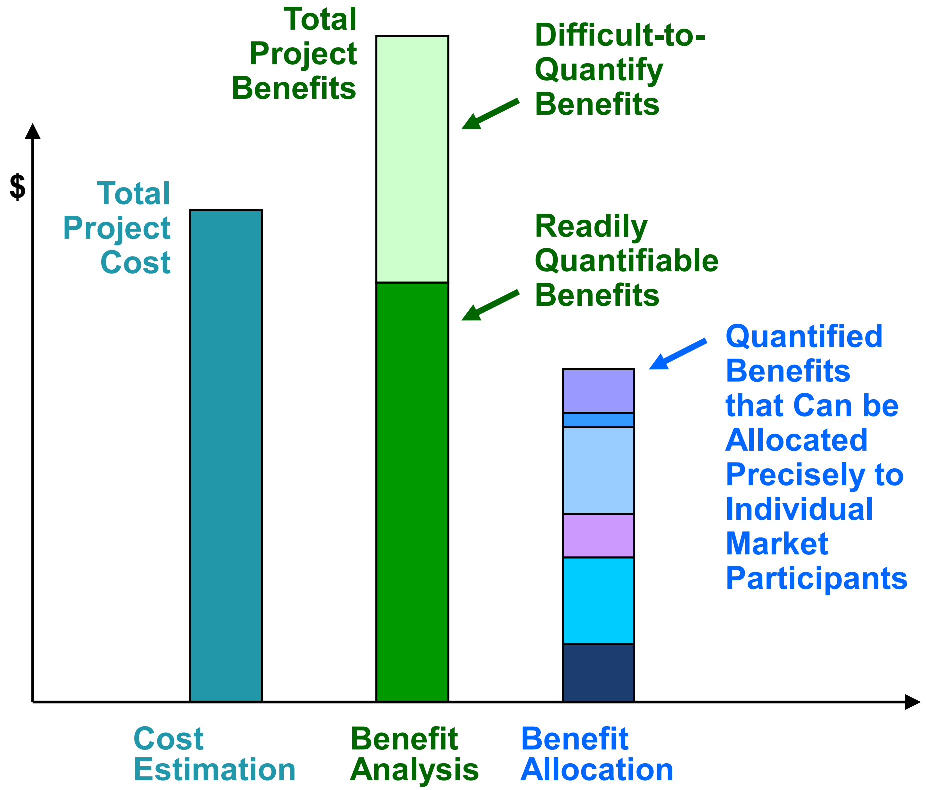
- MTEP17 analysis shows \$22 to \$75 billion in total benefits to MISO North and Central
- Total costs increased from \$5.6 to \$6.7 billion, but benefits grew even more
- B-C ratios change over time but exceed 1.5 to 2.6 in every zone

Source: https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf

Recommendation: Clearly Separate Benefit-Cost Analysis of Projects from Cost-Allocation of Approved Portfolios

Recommend 2-step approach:

1. Determine whether projects are beneficial overall, quantifying a broad set of benefits
   - Without quantifying most benefits, many desirable projects (or synergistic portfolios) will be rejected
   - Benefits that can be allocated precisely may only be a subset of total benefits
   - Avoid temptation to understate benefits in effort to reduce cost allocation to individual study participants
2. Evaluate how the cost of a broad portfolio of beneficial projects should be allocated roughly based on their joint distribution of benefits
   - Reduces conflict: a broad set of benefits quantified for a portfolio of projects tends to be more stable over time and be distributed more uniformly



Recommendation: Allocate costs "roughly commensurate" with (but not formulaically based on) quantified benefits

Transmission cost allocations that are formulaically based on quantified benefits are inherently contentious and counter productive:

- Quantified values of benefit metrics depend on analytical approach and assumptions
- Benefits vary across scenarios and can change quickly as current and projected market conditions change
- Market participants question benefit metrics, approaches, and assumptions that yield large allocations to them
- Tends to yield overly "conservative" (understated) benefit estimates … such that even very valuable transmission projects cannot meet the required B-C thresholds

Formulaic benefits-based allocations for individual projects yield the most contentious and often unexpected outcomes

- Benefits & utilization of individual projects change more significantly across scenarios and over time (with differences load growth, generation retirements/additions, other transmission investments, changes in fuel costs)
- Formulaic allocations based on individual benefit metrics (incl. physical power flows) have a track record of creating unexpected and contentious outcomes (e.g., DFAX-based in PJM)

Simple cost allocations that are roughly commensurate with a broad set of benefits quantified for a portfolio of transmission projects (such as SPP's highway-byway, MISO's MVP, or CAISO's regional/local approach) tend to be less contentious and have proven to be longer-lasting

Thank You!

(Additional Slides)

About the Speaker

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

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

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

Summary of Order 1920 (1920-A) cost allocation provisions*

Ex ante (default) methodology for long-term regional transmission cost allocation:

- Ex ante cost allocation method is meant to provide certainty before transmission projects are built
- Transmission providers must engage with states to develop (over 6-12 months) one or more *ex ante* "default" cost allocation methods that apply to long-term regional transmission facilities
- Proposed cost allocations must distribute costs in a manner that is at least roughly equal with estimated benefits
- Default allocation cannot be based on project types (such as reliability, economic, or public policy requirements)
- Transmission providers must involve states in any future changes to cost allocations; must file both their own and the states' cost allocation proposal, if different

State Agreement Process (permitted but not required):

- If implemented, gives states the opportunity to propose (prior to or within 6 months of project selection) an alternative cost allocation method for specific long-term regional transmission facilities
- Offers flexibility to customize processes and requirements. However, if no cost allocation agreement is reached, the default cost allocation will be used

Voluntary Funding Opportunities (required):

- States and interconnection customers must be provided with the opportunity to voluntarily fund the cost (or a portion) of a facility that otherwise would not meet the planning entity's selection criteria

* For a more detailed overview, see Order 1920 Explainer and Order 1920-A Summary

Agreeing on cost-allocation is critical, challenging, and possible

Easiest: develop “needed” local and regional reliability and generation interconnection transmission projects that do not involve cost sharing (now majority in many regions)

Harder: regionally share costs of transmission “needed” to meet regional reliability standards

- Most TOs strongly prefer recovering costs associated with their own ratebase
- Policy makers reluctant to share costs of distant projects in other states

Even harder: share costs of economic or public-policy projects:

- Planning challenged by often fundamentally different views of the future
    - State policy makers may disagree on key planning assumptions, such as fuel prices, technology options, and public policy objectives (e.g., environmental policies or load growth from electrification and economic development support)
- Large regional projects for environmental or economic development (e.g., data center) policies pit states that have them (often with major population centers) against states that don’t (often more remote areas)
- Reluctance to pay for transmission that facilitates out-of-state generation investments with few in-state jobs

Hardest: cost allocation for interregional projects; few models and little experience because no significant interregional projects have been planned in the last decade

Basic cost allocation and recovery mechanisms

1) **License Plate:** each utility "locally" recovers the costs of its transmission investments (usually located within its footprint). Example: used for all MISO "reliability" and all RTOs' "local" projects
2) **Beneficiary Pays:** various formulas that allocate costs of transmission investments to individual Transmission Owners (TOs) that benefit from a project, even if the project is not owned by the beneficiaries. TOs then recover allocated costs in their License Plate tariffs from own customers
3) **Postage Stamps:** transmission costs are recovered uniformly from all loads in a defined market area
   - RTO-wide examples: ERCOT, >200kV in CAISO, >100kV in ISO-NE, Multi-Value Projects in MISO
   - Highway/Byway in SPP: postage stamp for all projects >300 kV; 1/3 postage stamp and 2/3 license plate for projects 100-300 kV; 100% license plate for projects below 100 kV
   - Often implemented by first allocating costs to TOs (e.g., on a MW or MWh load ratio share), who then recover these allocated costs in their license plate tariffs
4) **Direct Assignment/Participant Funding:** transmission costs (e.g. associated with generator interconnection or transmission service requests) are assigned to requesting entity
   - Innovative variance: CAISO's Tehachapi LCRI (up-front shared funding, later charged back to generators)
5) **Merchant Cost Recovery:** the project sponsors recover costs outside regulated tariffs through negotiated rates with individual long-term transmission service customers
6) **Co-ownership:** benefitting transmission owners co-own the facility (each recovering costs through rate base treatment); one operator, shared transmission rights (e.g., CAPX 2020; often used in WECC)

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

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 Ensuring Cost Effective Transmission to Support Affordable State Electricity Policies, NARUC Annual Meeting, Nov 13, 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

Order 1920's "Interregional Transmission Coordination" requirements

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."

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

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

PREPARED FOR
WIRES

Link: Well-Planned Transmission

PREPARED BY
Judy W. Chang
Johannes P. Pfeifenberger

May 2016

THE Brattle GROUP

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

PREPARED FOR
WIRES

Link: Effective Transmission Planning

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

April 2015

The Brattle Group

Link: Transmission Benefits

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

July 2013

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

Link: Diversity Value

BU
Boston University Institute for Sustainable Energy

The Value of Diversifying Uncertain Renewable Generation through the Transmission System

September • 2020

A Roadmap to Improved Interregional Transmission Planning

Link: Interregional Roadmap

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

November 30, 2021

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

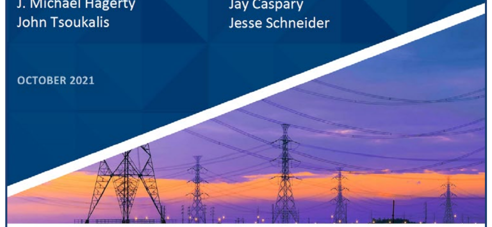
Link: Brattle Grid Strategies

PREPARED BY

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

Grid Strategies:
Rob Gramlich
Michael Goggin
Jay Caspary
Jesse Schneider

OCTOBER 2021



Brattle
GRID STRATEGIES LLC

Summarizes proven approaches to quantifying various benefits

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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

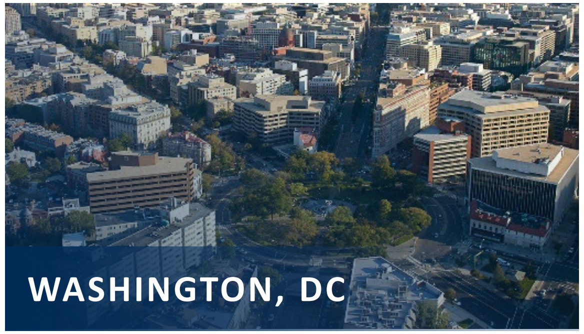
LITIGATION

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



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